ONE-HUNDRED TENTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

Volume I

ISSUED FROM
JANUARY 1, 2020 THROUGH DECEMBER 31, 2020

ONE-HUNDRED TENTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2020, through December 31, 2020

Charlotte A. Mitchell, Chair

ToNola D. Brown-Bland, Commissioner

Lyons Gray, Commissioner

Daniel G. Clodfelter, Commissioner

Kimberly W. Duffley, Commissioner

Jeffrey A. Hughes, Commissioner

Floyd B. McKissick, Jr., 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.

LETTER OF TRANSMITTAL

December 31, 2020

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, 2020, we hereby present for your consideration the report of the Commission's significant decisions for the 12-month period beginning January 1, 2020, and ending December 31, 2020.

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

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Kimberley A. Campbell, Chief Clerk

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OF THE
NORTH CAROLINA UTILITIES COMMISSION

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NOTE: For Printed General Orders, see Index on Page 1297

GENERAL ORDERS – ELECTRIC

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 QUEUE REFORM

BY THE COMMISSION: On June 14, 2019, the Commission issued its Order Approving Revised Interconnection Standard and Requiring Reports and Testimony in this docket. Among other things, that Order required:

> 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.

On July 31, 2019, Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC (together, Duke), filed an update as to the three stakeholder meetings already hosted and plans to host additional such meetings. Duke noted that there "are substantial hurdles to implementing a fundamental change to the interconnection process." Duke also noted that a "substantial degree of consensus" would be needed in order to secure the approvals needed not only in North Carolina but also in South Carolina and from the federal government.

On August 27, 2019, the Commission issued its Order Requiring Queue Reform Proposal and Comments in which it required Duke to file a queue reform proposal on or before October 15, 2019, and established deadlines for parties to file comments and for the utilities to file responsive comments.

On May 15, 2020, after a series of requests for extensions of time were granted, Duke filed its queue reform proposal. On June 15 and 16, 2020, comments were filed by the Public Staff, jointly by the North Carolina Clean Energy Business Alliance (NCCEBA) and the North Carolina Sustainable Energy Association (NCSEA), and GreenGo Energy US, Inc. Subsequently, on July 8, 2020, Duke filed a motion for extension of time to file reply comments in which it requested additional time to determine whether additional consensus could be reached among the parties. The Commission granted that request on July 13, 2020, and a second such request on August 13, 2020.

On August 31, 2020, Duke filed reply comments and a revised queue reform proposal that reflected further negotiations of the parties. Also on August 31, 2020, comments were filed by the Public Staff and Dominion Energy North Carolina (DENC), and joint comments were filed by NCCEBA and NCSEA.

In its comments on the revised proposal the Public Staff expresses support for the revised queue reform proposal as a "reasonable initial approach to improve and reform the interconnection process . . . ." Additionally, the Public Staff recommends that Duke: 1) file reports after the completion of the transitional cluster study process and the initial "DISIS[1] Cluster," describing the outcomes of those initial group studies, and 2) engage stakeholders at that time regarding whether additional queue reform efforts are needed.

Similarly, NCCEBA and NCSEA express support for the revised queue reform proposal.

Finally, DENC expresses support for the revised queue reform proposal and notes that it provides DENC with the option not to implement the cluster study process but rather continue to implement the serial study process.

As has been noted in this and other dockets, the current serial approach to studying and processing Interconnection Requests has become problematic. In large parts of North Carolina it is not possible to add generation without the construction of expensive transmission upgrades. The current serial process assigns these upgrades to one generator, and the costs of these upgrades are typically too expensive for any one generator to absorb. The Commission agrees with parties who have stated that moving to a grouping study process is necessary in order to share the transmission upgrade costs among the multiple generation projects that contribute to the need for the transmission upgrades. The Commission determines that the revised queue reform proposal is structured to accomplish the objective of transitioning to a grouping study process. In addition, the proposal has substantial support from the stakeholders involved, and the Commission commends all parties for their efforts to reach consensus. For these reasons the Commission approves Duke's queue reform proposal as filed on August 31, 2020. As suggested by the Public Staff, the Commission directs Duke to report to the Commission on the results of the transitional cluster study as well as the results of the first DISIS.

In its petition Duke notes that in addition to the Commission, both the South Carolina Public Service Commission and the Federal Energy Regulatory Commission must approve its proposal. The Commission shall issue an order subsequent to the approval of the queue reform proposal in the other jurisdictions establishing the effective date of the new revised NCIP

IT IS, THEREFORE, ORDERED as follows:

1. That Duke's queue reform proposal as filed on August 31, 2020, is hereby approved;

2. That on or before November 13, 2020, Duke shall file a complete and correct redline of changes to the NCIP, compared to the current NCIP, required by Duke's queue reform proposal. That redline shall incorporate Attachment 2 (Transitional Cluster Study Agreement) and Attachment 3 (Conditions for Acceptance of Surety Bond as Financial Security for M4 Readiness Milestone) from Duke's August 31, 2020 filing;

3. That Duke shall provide an explanation of any changes to the NCIP included in the complete and correct redline that were not already described fully in Duke's earlier filings;

[1] Definitive Interconnection System Impact Study.

4. That Duke shall keep the Commission informed of its progress in securing approvals of its queue reform proposal from the South Carolina Public Service Commission and the Federal Energy Regulatory Commission and any required adjustments to its proposed transition schedule; and

5. That Duke shall file reports with the Commission regarding the outcome of the transitional cluster study and the initial DISIS cluster study as recommended by the Public Staff.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of October, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

DOCKET NO. E-100, SUB 113
DOCKET NO. M-100, SUB 158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 113 In the Matter of Rulemaking Proceeding to Implement Session Law 2007-397 DOCKET NO. M-100, Sub 158 In the Matter of Investigation of Necessary and Appropriate Responses to the Novel Coronavirus COVID-19	)	ORDER AMENDING RULE R8-65

BY THE COMMISSION: Commission Rule R8-65 provides for the filing of a report of proposed construction (RPC) by persons not required to obtain a certificate of public convenience and necessity (CPCN) before beginning construction of an electric generating facility, including most facilities with a capacity of less than two megawatts.

Due to the ongoing COVID-19 State of Emergency, and in order to improve the efficiency of the RPC filing process, the Commission finds good cause to implement the following changes to the Rule R8-65 filing requirements:

(1) Those persons who file hard copies of RPCs shall no longer provide the original and six copies. Instead they shall provide one original, verified copy. (The Commission made this change on a temporary basis in Docket No. M-100, Sub 158. With this order that change is now permanent.)

(2) RPCs for solar photovoltaic systems wherein solar panels are mounted on the roof of a residential or commercial building shall no longer be required to include a color map or aerial photo.

These changes to Commission Rule R8-65 and the revised filing form are shown in Appendix A and are effective immediately. Clean copies of the amended rule and filing form are attached as Appendix B.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of August, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A
PAGE 1 OF 7

Rule R8-65. REPORT BY PERSONS CONSTRUCTING ELECTRIC GENERATING FACILITIES EXEMPT FROM CERTIFICATION REQUIREMENT.

(a) All persons exempt from certification under G.S. 62-110.1(g) shall file with the Commission a report of the proposed construction of an electric generating facility before beginning construction of the facility. The report shall be in the form adopted by the Commission, shall include the information prescribed in subsection (g) below, and shall be signed and verified by the owner of the electric generating facility or by an individual duly authorized to act on behalf of the owner for the purpose of the filing. The facility owner shall also be required to report to the Commission the completion of each such facility by giving notice of the completion of construction to the Commission in accordance with section (i) of this Rule. Reports of proposed construction and notices of completion of construction shall be for informational purposes only, and shall not require action by the Commission or the Public Staff.

(b) Reports filed on behalf of a corporation are not subject to the provision of Rule R1-5(d) that requires corporate pleadings to be filed by a member of the Bar of the State of North Carolina. Should a public hearing be required, the requirements of G.S. 84-4 and G.S. 84-4.1 shall be applicable.

(c) The owner of the electric generating facility shall provide a copy of the report to the electric public utility, electric membership corporation, or municipality to which the generating facility is or will be interconnected. This requirement shall not apply to an offering utility, as defined in G.S. 62-126.3(10), with regard to an electric generating facility that is intended to be a community solar energy facility, as defined in G.S. 62-126.3(3).

(d) The owner of the electric generating facility shall file the report electronically or file an original ~~and 6 copies~~ of the report of proposed construction with the Chief Clerk of the Utilities Commission. The report shall be accompanied by the fee required by G.S. 62-300.

(e) Upon the filing of a report of proposed construction, the Chief Clerk will assign a new docket or sub-docket number to the filing.

(f) The Commission may order a hearing on the report of proposed construction upon its own motion or upon receipt of a complaint specifying the basis thereof. Otherwise, no acknowledgment of receipt of the report of proposed construction will be issued nor will any other further action be taken by the Commission.

(g) The Report.

(1) The report shall be comprised of the following four exhibits:

(i) Exhibit 1 shall contain:

a. The full and correct name, business address, business telephone number, and electronic mailing address of the facility owner;

b. A statement of whether the facility owner is an individual, a partnership, or a corporation and, if a partnership, the name and business address of each general partner and, if a corporation, the state and date of incorporation and the name, business address, business telephone number, and electronic mailing address of an individual duly authorized to act as corporate agent for the purpose of the report and, if a foreign corporation, whether domesticated in North Carolina; and

c. The full and correct name of the site owner and, if the owner is other than the facility owner, the facility owner's interest in the site.

(ii) Exhibit 2 shall contain:

a. A color map or aerial photo showing the location of the generating facility site in relation to local highways, streets, rivers, streams, and other generally known local landmarks, except such map or photo shall not be required for solar photovoltaic systems wherein solar panels are mounted on the roof of a residential or commercial building; and

b. The E911 street address, county in which the proposed facility will be physically located, and GPS coordinates of the approximate center of the proposed facility site to the nearest second or one thousandth of a degree.

(iii) Exhibit 3 shall contain:
   a. The nature of the generating facility, including the type and source of its power or fuel;
   b. A description of the buildings, structures and equipment comprising the generating facility and the manner of its operation;
   c. The gross and net generating capacity of each unit and the entire facility in alternating current (AC);
   d. The projected date on which the facility will come on line;
   e. The facility owner's general plan for sale of the electricity to be generated, including the utility to which the facility owner plans to sell the electricity;
   f. the service life of the project;
   g. the projected annual sales in kilowatt-hours; and

   h. whether the facility owner intends to earn renewable energy certificates that are eligible for compliance with the State's renewable energy and energy efficiency portfolio standard, and, if the facility to be constructed is a community solar energy facility, as defined in G.S. 62-126.3(3), a statement that the renewable energy certificates will be offered to subscribers in a manner consistent with G.S. 62-126.8(e)(8) and the electric public utility's consumer solar energy facility program approved by the Commission.

(iv) Exhibit 4 shall contain the expected cost of the proposed facility.

(2) All reports shall be signed and verified by the facility owner or by an individual duly authorized to aet on behalf of the facility owner for the purpose of the report.

(3) Falsification of or failure to disclose any required information in the report may be grounds for rejecting the report.

(4) Both before the time construction is completed and after, each facility owner shall advise both the Commission and the utility to which the generating facility is or will be interconnected of any plans to sell, transfer, or assign the generating facility or of any significant changes in the information set forth in subsection (g) of this Rule.

(i) Notice of completion of construction of facility. Within thirty (30) days of the completion of construction of the facility, each facility owner shall notify the Commission that the construction of the facility is complete. This notice shall be made by filing a short, plain statement that construction of the facility is complete and the date on which the construction was completed.

DOCKET NO.____-_______, SUB ______

Filing Fee Tendered $________________

Report of Proposed Construction (RPC) – Commission Rule R8-65

Pursuant to G.S. 62-110.1(g), any person who seeks to construct an electric generating facility in North Carolina, and is exempt from the requirement to obtain a certificate of public convenience and necessity, is required to file this form and a notice of completion of the construction of the facility. This form may be accompanied by any exhibits or additional responses incorporated by reference thereto and attached to this form. This form must be accompanied by the required filing fee of $50.00.

This form may be electronically filed. Please see www.ncuc.net for instructions.

If this form is filed by hard copy, the original ~~plus 6 copies~~ must be presented at or transmitted to the office of the Chief Clerk. Regardless of the method of delivery, this form is not deemed filed until it is received by the Chief Clerk, along with the required filing fee.

The mailing address is:

Chief Clerk
NC Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-43~~25~~00

Exhibits required by Rule R8-64(b)		Applicant's Response
(1)(i)	Full and correct name of the owner of the facility	
	Facility name	
	Business address	
	E-mail address	
	Telephone number	
(ii)	The owner is (check one)	☐ Individual ☐ Partnership ☐ Corporation
	If a partnership, the name and business address of each general partner	
	If a corporation, the state and date of incorporation	
	If a partnership, the name and address of each general partner (add additional sheets if necessary)	

	Owner's agent for purposes of this report, if applicable:	
	Agent's business address	
	Agent's e-mail address	
	Agent's telephone number	
(iii)	The full and correct name of the site owner and, if the site owner is other than the applicant, the applicant's legal interest in the site	
(2)(i)	Attach a color map or aerial photo showing the location of the generating facility site in relation to local highways, streets, rivers, streams, and other generally known local landmarks with the proposed location of major equipment indicated on the map or photo, including: the generator, fuel handling equipment, plant distribution system, startup equipment, the site boundary, planned and existing pipelines, planned and existing roads, planned and existing water supplies, and planned and existing electric facilities. A U.S. Geological Survey map or an aerial photo map prepared via the State's geographic information system (found at www.gis.ncdcr.gov/hpoweb/) is preferred. Rooftop solar installations are not required to file a map or photo.	
(ii)	E911 street address of the proposed facility	
	County in which the proposed facility will be physically located	
	GPS coordinates of the approximate center of the proposed facility site to the nearest second or one thousandth of a degree	
(3)(i)	The nature of the facility, including its technology, and the source of its power and fuel(s)	
(ii)	A description of the buildings, structures and equipment comprising the generating facility and the manner of its operation	
(iii)	The gross and net projected maximum dependable capacity of the facility in megawatts – Alternating Current	

	The facility's nameplate capacity in megawatts – Alternating Current	
(iv)	The projected date on which the facility will come on line	
(v)	The applicant's general plan for sale of the electricity to be generated, including the name of utility to which the applicant plans to sell the electricity	
(vi)	Any provisions for wheeling of the electricity, if applicable	
(vii)	Arrangements for firm, non- firm, or emergency generation, if applicable	
(viii)	The service life of the project	
(ix)	The projected annual sales in kilowatt-hours	
(x)	Whether the applicant intends to produce renewable energy certificates that are eligible for compliance with the State's renewable energy and energy efficiency portfolio standard ☐ Yes ☐ No	
(4)	The expected cost of the proposed facility	$

Confidentiality

If an applicant considers certain of the required information above to be confidential and entitled to protection from public disclosure, it may designate said information as confidential and file it under seal. Documents marked as confidential will be treated pursuant to applicable Commission rules, procedures, and orders dealing with filings made under seal and with nondisclosure agreements.

Verification

All reports shall be signed and verified (notarized) by the applicant or by an individual duly authorized to act on behalf of the applicant for the purpose of the report. A blank verification page is attached below.

VERIFICATION

STATE OF ________________________ COUNTY OF ____________________

____ ____________________________
Signature of Owner's Representative or Agent Title of Representative or Agent

____
Typed or Printed Name of Representative or Agent

The above named person personally appeared before me this day and, being first duly sworn, says that the facts stated in the foregoing report and any exhibits, documents, and statements thereto attached are true as he or she believes.

WITNESS my hand and notarial seal, this ______day of _______________, 20 ____

My Commission Expires: ___________________________

____
Signature of Notary Public

____
Name of Notary Public – Typed or Printed

~~This original verification must be affixed to the original report, and a copy of this verification must be affixed to each of the copies that are also submitted to the Commission.~~

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c. The full and correct name of the site owner and, if the owner is other than the facility owner, the facility owner's interest in the site.

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e. The facility owner's general plan for sale of the electricity to be generated, including the utility to which the facility owner plans to sell the electricity;
f. the service life of the project;
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(x)	Whether the applicant intends to produce renewable energy certificates that are eligible for compliance with the State's renewable energy and energy efficiency portfolio standard ☐ Yes ☐ No	
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If an applicant considers certain of the required information above to be confidential and entitled to protection from public disclosure, it may designate said information as confidential and file it under seal. Documents marked as confidential will be treated pursuant to applicable Commission rules, procedures, and orders dealing with filings made under seal and with nondisclosure agreements.

Verification

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VERIFICATION

STATE OF ______________________ COUNTY OF ____________________

______________________________ ______________________________
Signature of Owner's Representative or Agent Title of Representative or Agent

____
Typed or Printed Name of Representative or Agent

The above named person personally appeared before me this day and, being first duly sworn, says that the facts stated in the foregoing report and any exhibits, documents, and statements thereto attached are true as he or she believes.

WITNESS my hand and notarial seal, this ______ day of ____________________, 20 ______

My Commission Expires: ________________________

____
Signature of Notary Public

____
Name of Notary Public – Typed or Printed

DOCKET NO. E-100, SUB 113

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Rulemaking Proceeding to Implement Session Law 2007-397	)))	ORDER MODIFYING THE SWINE WASTE SET-ASIDE REQUIREMENTS AND PROVIDING OTHER RELIEF

BY THE COMMISSION: On September 25, 2020, a verified motion to modify and delay the requirements of N.C. Gen. Stat. § 62-133.8(e) was filed jointly by North Carolina Electric Membership Corporation (NCEMC); Fayetteville Public Works Commission (FPWC); EnergyUnited Electric Membership Corporation (EnergyUnited); the Tennessee Valley Authority (TVA); the Town of Waynesville (Waynesville); North Carolina Eastern Municipal Power Agency (NCEMPA); and North Carolina Municipal Power Agency Number 1 (NCMPA1) (hereinafter referred to collectively as the Joint Movants)[1] seeking Commission approval to (1) modify the swine waste set-aside requirements of the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS) by delaying the compliance requirements for the electric municipal corporations (EMCs) and municipalities (Munis) for one year; (2) allow the EMCs and Munis to bank any swine waste-derived renewable energy certificates (RECs) previously or subsequently acquired for use in future compliance years; and (3) allow the EMCs and Munis to replace compliance with the swine waste set-aside requirement in 2020 with other compliance measures in accordance with N.C.G.S. § 62-133.8(b), (c), and (d). The Joint Movants state that they have individually and collectively made reasonable efforts to comply with the swine waste set-aside requirements and argue that the relief sought is in the public interest. The Joint Movants note that they are not requesting a modification of the poultry waste set-aside requirements of N.C.G.S. § 62-133.8(f) as part of this Joint Motion. Finally, the Joint Movants request that the Commission consider and approve their motion without an evidentiary hearing because they believe that through required semiannual reports and stakeholder meetings, stakeholders and regulatory staff have ample information surrounding the EMC's and Muni's compliance efforts.

On November 20, 2020, the Commission issued an Order Requesting Comments. On November 24, 2020, the Public Staff filed a letter detailing two stakeholder meetings held in 2020

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[1] NCEMPA states that it is acting in its capacity as REPS compliance aggregator for 23 North Carolina distribution electric membership corporations, two cooperatives headquartered outside of North Carolina, and three North Carolina towns which are electric power suppliers. TVA states that it is acting in its capacity as REPS compliance aggregator for Blue Ridge Mountain Electric Membership Corporation, Mountain Electric Cooperative, Tri-State Electric Membership Corporation and Murphy Electric Power Board which are electric suppliers. NCEMPA states that it is acting in its capacity as REPS compliance aggregator for its 32 member municipalities which are power suppliers. NCMPA1 asserts that it is acting in its capacity as REPS compliance aggregator for its 19 member municipalities which are electric power suppliers.

Further, based on information submitted in the Public Staff's Motion for Leave to File Supplement Comments and Supplemental Comments of Public Staff on Joint Motion to Delay the 2020 Swine Waste Set-Aside Requirements for Certain Electric Power Suppliers detailed in this Order on page 4, the term Joint Movants shall be understood to refer to the parties to this matter as well as all electric membership corporations and municipalities in North Carolina regardless of their participation as a party to the Joint Motion.

in response to the Commission's December 16, 2019 Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief (2019 Delay Order). The Public Staff and the North Carolina Pork Council (NCPC) filed comments on December 3 and 7, 2020, respectively. On December 4, 2020, Optima MH, LLC (Optima MH), filed a Petition to Intervene and Initial Comments. No other party filed comments on the motion. On December 9, 2020, the Commission issued an order granting Optima MH's petition to intervene.

On December 10, 2020, the Joint Movants filed a Motion for Leave to File Reply Comments. By Order dated December 14, 2020, the Commission denied the Joint Movants' motion but noted it would consider the prospective reply comments included with the Joint Movants' motion.

On December 15, 2020, the Public Staff filed a Motion for Leave to File Supplemental Comments and Supplemental Comments on the Joint Motion to Delay the 2020 Swine Waste Set-Aside Requirements for Certain Electric Power Suppliers (Supplemental Comments). The Commission granted the Public Staff's Motion and accepted its Supplemental Comments on December 21, 2020.

SUMMARY OF THE COMMENTS

In its comments Optima MH asserts that the Joint Movants have not made reasonable efforts to comply with the swine waste set-aside requirements. Optima MH states that NCEMC failed to engage in more than initial discussions with Optima MH regarding the development of a project that would produce swine waste RECs for NCEMC or any of its member cooperatives. Optima MH further states that NCEMC's failure to continue negotiations placed Optima in a "new dimension of development limbo — preventing the project from being financed and built" — and that NCEMC should have provided more detail to the Commission regarding the project in its Joint Motion. Additionally, Optima MH states that NCEMC indicated that the pricing of the swine waste RECs was the sole reason NCEMC did not negotiate further with Optima MH and that "[i]f NCEMC had diligently evaluated and accepted . . . Optima's proposal, the project could have been constructed and would have been generating RECs in 2020." Optima MH questions the Joint Movants' willingness to actually purchase swine waste RECs from its projects. Optima MH warns the Commission to be skeptical of claims that prices for swine waste RECs are unreasonable and states that an off-ramp from the statutory REPS requirements pursuant to Commission Rule R9-67 "should be deemed to be extraordinary relief and not routinely relied upon or sought as a *de facto* matter of course." Optima MH does not expressly oppose the Joint Motion but asks the Commission to keep its concerns in the forefront in any future requests for "off-ramps from swine waste RECs set-aside requirements."

In its comments NCPC states that it does not oppose the Joint Movants' motion. However, NCPC expresses frustration with what it perceives as the Joint Movants' "nonchalant approach to the set-aside requirements," and discusses avenues which the Joint Movants can pursue more aggressively in their attempts to comply with the swine waste set-aside requirements. In stating that a new approach by the Joint Movants is warranted, NCPC recommends that as a condition of granting the Joint Movants' motion, the Commission should require the movants, jointly and individually, to submit a detailed compliance plan showing how each intends to achieve compliance with the swine waste set-aside requirements. While NCPC desires a change in the future actions of the Joint Movants, it supports granting the Joint Movants' requests without an evidentiary hearing.

The Public Staff's letter detailing its two stakeholder meetings briefly summarizes the topics of discussion regarding supply-side shortages that impacted the availability of swine waste set-aside RECs and whether these shortages are due to technology, REC prices, or interconnection issues. The letter also references discussion of the challenges experienced with the swine-waste-to-energy project owned by North Carolina Renewable Power – Lumberton, LLC, including the project's viability and impact on REC contracts, as well as an industry shift from on-farm generation to directed biogas technology. The Public Staff in its comments states that the semiannual reports of the EMCs and the Munis indicate that they are making good faith efforts to comply with the swine waste set-aside requirements but will be unable to comply in 2020. The Public Staff's analysis of the semiannual reports concludes that "most EMC/Muni Suppliers do not have sufficient in-state swine waste RECs to comply with a 0.04% requirement, much less the 0.07% requirement" set in the 2019 Delay Order. The Public Staff indicates that requiring retirement of banked swine waste-derived RECs will deplete the supply of RECs and make compliance more difficult in subsequent years. Based upon its review of this data, the Public Staff recommends that the Commission grant the EMCs and Munis requested modifications to the swine waste set-aside requirements without an evidentiary hearing. The Public Staff requests that the Commission direct the EMCs and Munis that are subject to the semiannual filing requirement to continue to submit semiannual reports consistent with the schedule and format required by the December 1, 2015 Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief (2015 Delay Order) issued in this docket.

In their Reply Comments, the Joint Movants point out that NCPC and Optima MH do not request that the Joint Motion be denied, but instead their comments focus on "prospective" relief. The Joint Movants do not take issue with NCPC's recommendation that directed biogas should continue to be explored, but they do oppose NCPC's proposal for an additional compliance filing atop the semiannual reports currently provided. In response to Optima MH's comments, the Joint Movants state that "an electric supplier's status of being 'below the statutory cap' has never been the sole determinant of whether its compliance efforts were reasonable, nor whether a particular REC purchase contract should have been entered into." The Joint Movants cite the Commission's prior decision not to inject itself in the electric power suppliers' decision-making process and state that NCEMC's decision not to contract with Optima MH was disclosed in its semiannual report. The Joint Movants further provide that both NCPC and Optima MH have provided selective information in their comments omitting information regarding a Request for Proposal (RFP) from a group including the Joint Movants and that Optima did not submit a proposal in response to the RFP.

In its Supplemental Comments the Public Staff clarifies that in its December 3 Comments, it included Carolina Power Partners (CPP)[1] with the Joint Movants as EMCs or Munis for purposes

[1] CPP is not an electric power supplier under N.C.G.S. § 62-133.8 but is acting in its capacity as a compliance aggregator for the City of Concord, the City of Kings Mountain, the Town of Black Creek, the Town of Lucama, the Town of Sharpsburg, the Town of Stantonsburg, and the Town of Winterville.

of its comments and recommendation even though CPP did not join the Joint Motion. Additionally, the Public Staff states that after contacting counsel with Duke Energy Carolinas, LLC (DEC),[1] and Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC),[2] even though neither DEC nor DENC is a party to the Joint Motion they authorize the Public Staff to request that the EMCs and Munis for which they provide REPS compliance services receive the same treatment provided to Joint Movants.

DISCUSSION

Pursuant to N.C.G.S. § 62-133.8(i)(2), the Commission, in developing rules implementing the REPS, shall:

> Include a procedure to modify or delay the provisions of subsections (b), (c), (d), (e), and (f) of this section in whole or in part if the Commission determines that it is in the public interest to do so. The procedure adopted pursuant to this subdivision shall include a requirement that the electric power supplier demonstrate that it made a reasonable effort to meet the requirements set out in this section.

Commission Rule R8-67(c)(5) states:

> In any year, an electric power supplier or other interested party may petition the Commission to modify or delay the provisions of N.C.G.S. § 62-133.8(b), (c), (d), (e) and (f), in whole or in part. The Commission may grant such petition upon a finding that it is in the public interest to do so. If an electric power supplier is the petitioner, it shall demonstrate that it has made a reasonable effort to meet the requirements of such provisions.

The Commission has previously exercised this authority and delayed compliance with the swine and poultry waste set-aside requirements on several occasions by the following orders issued in this docket: the November 29, 2012 Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Granting Other Relief; the March 26, 2014 Final Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Providing Other Relief; the November 13, 2014 Order Modifying the Swine Waste Set-Aside Requirement and Providing Other Relief; the 2015 Delay Order; the October 17, 2016 Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief; the October 16, 2017 Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief; the October 8, 2018 Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief; and the 2019 Delay Order (collectively, Delay Orders).

As an initial matter the Commission considers the Joint Movants' request to consider and approve their motion without the need for an evidentiary hearing. In support of this request, the Joint Movants state that the compliance status for the swine waste set-aside requirements is

[1] DEC serves as the REPS compliance aggregator for Blue Ridge Electric Membership Corporation, Rutherford Electric Membership Corporation, the Town of Dallas, the Town of Forest City, and the Town of Highlands.

[2] DENC provide REPS compliance services for the Town of Windsor.

essentially unchanged since the Commission issued its 2019 Delay Order. The motion is verified by Andrew M. Fusco, Vice President, Member Services and Corporate Planning, for ElectriCities of North Carolina, Inc., pursuant to Commission Rule R1-7 on behalf of the Joint Movants. The Public Staff, like the Joint Movants, recommends that the Commission approve the request without an evidentiary hearing. No party filed comments opposing this portion of the motion. Based upon the foregoing, the Commission finds that the material facts in this matter, including those contained in the Joint Movants' verified motion and in the semiannual reports filed in Docket No. E-100, Sub 113A, are uncontroverted and concludes that the motion may appropriately be decided without an evidentiary hearing.

Based on the semiannual reports submitted by the EMCs and Munis in Docket No. E-100, Sub 113A, the verified motion, the parties' comments, and the entire record herein, the Commission finds that the EMCs and Munis have made a reasonable effort to comply with the 2020 statewide swine waste set-aside requirement established by N.C.G.S. § 62-133.8(e) but will not be able to comply. Compliance with the swine waste set-aside requirements has been hindered by the fact that the technology of power production from swine waste continues to face challenges and that swine waste-to-energy projects continue to experience operational difficulties. While Optima MH asserts that had certain contracts been finalized for facility construction, it could have produced swine RECs in 2020, neither it nor any other party presented evidence that the aggregate 2020 swine waste set-aside requirement could be met.

The Commission's Delay Orders have noted that while electric power suppliers have been able to comply with the modified poultry waste set-aside requirements and some electric power suppliers have been able to comply with the modified swine waste set-aside requirements through a graduated increase in these requirements, other electric power suppliers have not been able to meet the swine waste RECs requirements. Industry advances discussed in the comments of Optima MH and NCPC indicate that encouraging developments are occurring in the technology of power production from swine waste which, when combined with the availability of RECs banked from current and prior years, would increase the likelihood that compliance with the swine waste set-aside requirements will be achieved at some point. The Commission finds that the verified Joint Motion along with the comments filed by Optima MH, NCPC, the Reply Comments of NCEMC, and the Supplemental Comments filed by the Public Staff demonstrate that the point of achieving compliance or partial compliance with the swine waste set-aside requirements for the EMCs and Munis has not yet arrived. The Commission agrees with the Public Staff that requiring the EMCs and Munis to meet the 2020 swine waste set-aside requirement established in the 2019 Delay Order would derail the progress made to date by the EMCs and Munis and render compliance for 2020 and future years difficult or impossible. Such action is not in the public interest. Therefore, consistent with the 2019 Delay Order, the Commission determines that it is in the public interest to delay entirely the 2020 swine waste set-aside requirement for one additional year for the EMCs and Munis; allow the EMCs and Munis that have acquired swine waste RECs for 2020 REPS compliance to bank such RECs for swine waste set-aside compliance in future years; and allow the EMCs and Munis to replace compliance with the swine waste set-aside requirement in 2020 with other compliance measures in accordance with N.C.G.S. § 62-133.8(b), (c), and (d).

The Commission notes the frustration expressed by NCPC and Optima MH and agrees that aggressive problem solving will be required by all parties for the EMCs and Munis to achieve compliance with swine waste set-aside requirements. Therefore, the Commission finds that the EMCs and Munis, or their utility compliance aggregator, shall be required file with the Commission a one-time compliance plan detailing the efforts and actions they intend to take to comply with the swine waste set-aside requirements for 2021 and future years. The Commission cautions the EMCs and Munis that they are mandated to use reasonable efforts, which include consideration of novel technologies and different approaches, to comply with the swine waste set-aside requirement set forth in this order for compliance in 2021.

While the Commission does not intend to interject itself into the parties' negotiations, failure to communicate with swine waste developers is directly relevant to the question of whether the electric power suppliers have made a good faith effort to comply with the swine waste set-aside requirements. Accordingly, the Commission expects that through collaborative efforts with interested stakeholders and the Public Staff, the EMCs and Munis will be in a position to make great progress in achieving compliance with swine-waste REC reporting in the coming year. Accordingly, the EMCs and Munis should continue all reasonable efforts to comply with the swine waste set-aside requirements as modified by this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That the swine waste set-aside requirements of N.C.G.S. § 62-133.8(e) for electric membership corporations and municipalities shall be, and are hereby, modified according to the following schedule:

Calendar Year	Requirement for Swine Waste Resources
2020	0.00%
2021	0.07%
2022-2024	0.14%
2025 and thereafter	0.20%

2. That the electric membership corporations and municipalities shall be allowed to bank any swine waste RECs previously or subsequently acquired for use in future compliance years and to replace compliance with the swine waste set-aside requirement in 2020 with other compliance measures pursuant to N.C.G.S. § 62-133.8(b) and (c), including the use of solar RECs beyond the requirements of N.C.G.S. § 62-133.8(d);

3. That the electric membership corporations and municipalities subject to the semiannual filing requirement shall continue to report on the schedule established in the 2015 Delay Order. These reports shall continue to include the information specified in Ordering Paragraph 3 of the Commission's 2015 Delay Order;

4. That, in addition to the semiannual filing requirements, the electric membership corporations and municipalities, or their utility compliance aggregator, shall be required to submit to the Commission, within six months of the date of this order, a one-time compliance plan detailing their intended efforts and actions to comply with the swine waste set-aside requirements for 2021 and future years; and

5. That the Chief Clerk is directed to deliver a copy of this Order to the NC-RETSAdministrator.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of December, 2020.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

DOCKET NO. E-100, SUB 158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018	)))	ORDER ESTABLISHING STANDARD RATES AND CONTRACT TERMS FOR QUALIFYING FACILITIES

HEARD: Tuesday, February 19, 2019, at 9:30 a.m., in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Monday, July 15, 2019, at 1:30 p.m., in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chair Charlotte A. Mitchell, Presiding; and Commissioners ToNola D. Brown-Bland, Lyons Gray, and Daniel G. Clodfelter

APPEARANCES:

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

Kendrick C. Fentress, Associate General Counsel, Duke Energy Corporation, 410 South Wilmington Street, NCRH 20, Raleigh, North Carolina 27601

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:

Mary Lynne Grigg and Nick Dantonio, McGuireWoods LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For North Carolina Sustainable Energy Association:

Benjamin Smith, Regulatory Counsel, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27604

For Carolina Utility Customers Association, Inc.:

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

For Cube Yadkin Generation LLC:

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

For North Carolina Clean Energy Business Alliance and Ecoplexus, Inc.:

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

For North Carolina Clean Energy Business Alliance:

Steven Levitas, Kilpatrick Townsend, 4208 Six Forks Road, Suite 1400, Raleigh, North Carolina 27609

For North Carolina Small Hydro Group:

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

For NC WARN, Inc.:

Kristen L. Wills, Staff Attorney, NC WARN, Inc., 2812 Hillsborough Road, Durham, North Carolina 27715

Matthew D. Quinn, Lewis & Roberts, PLLC, 3700 Glenwood Avenue, Suite 410, Raleigh, North Carolina 27612

For Southern Alliance for Clean Energy:

Lauren J. Bowen, Senior Attorney, and Maia Hutt, Associate Attorney, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For the Using and Consuming Public:

> Jennifer T. Harrod, Special Deputy Attorney General, and Teresa Townsend, Special Deputy Attorney General, North Carolina Department of Justice, 114 West Edenton Street, Raleigh, North Carolina 27603
>
> Tim R. Dodge, Lucy E. Edmondson, Layla Cummings, and Heather D. Fennell, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: This is the 2018 biennial proceeding held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 18 U.S.C. § 824a-3, and the Federal Energy Regulatory Commission's (FERC) regulations implementing those provisions, which delegates responsibilities in that regard to this Commission. This proceeding is also held pursuant to N.C. Gen. Stat. § 62-156, which requires this Commission to determine the rates to be paid by electric public utilities for power purchased from small power producers, as defined in N.C.G.S. § 62-3(27a).

Section 210 of PURPA and the regulations promulgated thereto by the FERC prescribe the responsibilities of the FERC and of state regulatory authorities, such as this Commission, relating to the development of cogeneration and small power production. Section 210 of PURPA requires the FERC to adopt such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. In adopting such rules, the FERC stated:

> Under section 201 of PURPA, cogeneration facilities and small power production facilities which meet certain standards and which are not owned by persons primarily engaged in the generation or sale of electric power can become qualifying facilities [QFs], and thus become eligible for the rates and exemptions set forth under section 210 of PURPA.

Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, Order No. 69, FERC Stats. & Regs. ¶ 30,128 (cross-referenced 10 FERC ¶ 61,150), *order on reh'g*, Order No. 69-A, FERC Stats. & Regs. ¶ 30,160 (1980) (cross-referenced at 11 FERC ¶ 61,166), *aff'd in part & vacated in part sub nom. Am. Elec. Power Serv. Corp. v. FERC*, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part sub nom. Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402 (1983).

Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities that obtain QF status. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, are in the public interest, and do not discriminate against cogenerators or small power producers. FERC regulations require that the rates electric utilities pay to purchase electric energy and capacity from qualifying cogenerators and small power producers reflect the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers.

With respect to electric utilities subject to state regulation, the FERC delegated the implementation of these rules to state regulatory authorities. State commissions may implement these rules by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the FERC's rules. The Commission implements Section 210 of PURPA and the related FERC regulations by holding biennial proceedings as required by N.C.G.S. § 62-156. The instant proceeding is the latest such proceeding to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate avoided cost rates to be paid by the electric utilities subject to the Commission's jurisdiction to the QFs with whom they interconnect. The Commission has also reviewed and addressed other matters involving the relationship between the electric utilities and QFs, including terms and conditions of service, contractual arrangements, and interconnection charges.

As noted above, this proceeding also results from the mandate of N.C.G.S. § 62-156, which was enacted by the General Assembly in 1979. This statute provides that, "no later than March 1, 1981, and at least every two years thereafter," the Commission shall determine the rates to be paid by electric public utilities for power purchased from small power producers according to certain standards prescribed in the FERC regulations regarding factors to be considered in the determination of avoided cost rates. The General Assembly recently amended N.C.G.S. § 62-156 in 2017 through enactment of Session Law 2017-192 (House Bill 589) and again in 2019 through enactment of Session Law 2019-132 (House Bill 329).

On June 26, 2018, the Commission issued in this docket an Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Hearing (2018 Scheduling Order). Pursuant to the 2018 Scheduling Order, Duke Energy Carolinas, LLC (DEC); Duke Energy Progress, LLC (DEP, and together with DEC, Duke); Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC, and together with DEC and DEP, the Utilities); Western Carolina University (WCU); and New River Light and Power Company (New River) were made parties to the proceeding. The 2018 Scheduling Order specifically directed the Utilities to address issues as required by Ordering Paragraph No. 16 of the Commission's October 11, 2017 Order in the last avoided cost proceeding, Docket No. E-100, Sub 148 (2016 Sub 148 Order), in presenting their avoided cost rates and terms in this proceeding, and further stated that the Commission would attempt to resolve all issues arising in this docket based on a record developed through public witness testimony, statements, exhibits, and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on the statements, exhibits, and schedules rather than a full evidentiary hearing. The 2018 Scheduling Order also established deadlines for the filing of petitions to intervene, initial comments and exhibits in response to the Utilities' filings, reply comments, and proposed orders. The 2018 Scheduling Order also scheduled a public hearing for February 19, 2019, solely for the purpose of taking non-expert public witness testimony. Finally, the 2018 Scheduling Order required the Utilities to publish notice in newspapers having general circulation in their respective North Carolina service areas and submit affidavits of publication no later than the date of the hearing.

The following parties filed timely petitions to intervene that were granted by the Commission: Carolina Utility Customers Association, Inc. (CUCA); Cube Yadkin Generation LLC (Cube Yadkin); Ecoplexus, Inc. (Ecoplexus); North Carolina Clean Energy Business Alliance (NCCEBA); North Carolina Small Hydro Group (NC Small Hydro Group); North Carolina Sustainable Energy Association (NCSEA); NC WARN, Inc. (NC WARN); and Southern Alliance for Clean Energy (SACE). Participation of the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e). The North Carolina Attorney General's Office gave notice of its intervention pursuant to N.C.G.S. § 62-20.

On November 1, 2018, Duke filed the Joint Initial Statement and Exhibits of DEC and DEP, which were verified by Glen A. Snider; DENC filed its Initial Statement and Exhibits, which were verified by Bruce Petrie; and WCU and New River jointly filed their comments and proposed avoided cost rates, which was verified by Kevin W. O'Donnell. DENC subsequently revised its proposed standard offer rate schedules by filings on March 7, 2019, and March 14, 2019.

On November 13, 2018, Duke filed a motion for approval to implement temporary variable rate credits, which was allowed pursuant to the Commission's order issued on December 3, 2018.

On or before February 13, 2019, the following parties filed initial comments: NC WARN, NC Small Hydro Group, Cube Yadkin, NCSEA, SACE, and the Public Staff.

On February 19, 2019, the public hearing was held as scheduled. Three public witnesses testified.

On March 27, 2019, the following parties filed reply comments: Duke, DENC, NC Small Hydro Group, NCSEA, SACE, and the Public Staff.

On April 18, 2019, Duke filed an Agreement and Stipulation of Partial Settlement with the Public Staff pertaining to rate design methodology (Rate Design Stipulation).

On April 24, 2019, the Commission issued an order scheduling an evidentiary hearing in this proceeding, identifying the issues in dispute that would be considered at the hearing, and establishing deadlines for the filing of testimony prior to the hearing.

On May 21, 2019, DENC filed the direct testimony of Bruce E. Petrie, and Duke filed the testimony and exhibits of Glen A. Snider, Steven Wheeler, David B. Johnson, and Nick Wintermantel. On the same day, Duke also filed the Stipulation of Partial Settlement with the Public Staff Regarding Solar Integration Services Charge (SISC Stipulation).

On June 14, 2019, the Commission issued an order requiring the Utilities to file supplemental testimony and allowing the other parties to file responsive testimony specifically addressing the following question:

> what avoided cost rate schedule and contract terms and conditions apply when a [QF] adds battery storage to an electric generating facility that has (i) established a legally enforceable obligation (LEO), (ii) executed a power purchase agreement

(PPA) with the relevant utility, and/or (iii) commenced operation and sale of the electric output of the facility to the relevant utility pursuant to an established LEO and executed PPA.

On June 21, 2019, NCSEA filed the testimony of Ben Johnson, R. Thomas Beach, and Carson Harkrader; SACE filed the testimony of James F. Wilson and Brendan Kirby; and the Public Staff filed the testimony of Jeff Thomas and John R. Hinton.

On June 25, 2019, Duke filed the supplemental testimony of witness Snider on the addition of storage to existing QFs, and DENC filed the supplemental testimony of James M. Billingsley.

On July 3, 2019, Duke filed the rebuttal testimony of witnesses Snider, Wheeler, Johnson, and Wintermantel; DENC filed the rebuttal testimony of witness Petrie; NCSEA filed the supplemental responsive testimony of Tyler Norris; SACE filed the supplemental responsive testimony of Devi Glick; Ecoplexus filed the supplemental responsive testimony of Michael R. Wallace; and the Public Staff filed the supplemental responsive testimony of Dustin Metz.

On July 11, 2019, Duke filed the supplemental joint rebuttal testimony of witnesses Snider, Wheeler, and Johnson; DENC filed the supplemental rebuttal testimony of witness Billingsley.

On July 12, 2019, Duke filed a letter to the NC Small Hydro Group in response to their request to extend the current performance adjustment factor (PAF) beyond the term of the Stipulation of Settlement Among Duke Energy Carolina, LLC, Duke Energy Progress, LLC, and North Carolina Hydro Group (Hydro Stipulation), which was filed in the 2014 biennial avoided cost proceeding, Docket No. E-100, Sub 140, on June 24, 2014, and expires at the end of 2020.

On July 15, 2019, the Commission resumed the hearing, as scheduled, for the purpose of receiving expert witness testimony. Duke presented the testimony of witnesses Snider, Wheeler, Johnson, and Wintermantel. DENC presented the testimony of witnesses Petrie and Billingsley. NCSEA presented the testimony of witnesses Beach, Johnson, and Norris. SACE presented the testimony of witnesses Kirby, Wilson, and Glick. Ecoplexus presented the testimony of witness Wallace. The Public Staff presented the testimony of witnesses Thomas, Hinton, and Metz. The prefiled testimony of those witnesses who testified at the evidentiary hearing, as well as all other witnesses filing testimony in this docket (with the exception of NCSEA witness Harkrader), were copied into the record as if given orally from the stand. Ms. Harkrader's prefiled testimony was allowed to be considered as a consumer statement of position.

On August 2, 2019, and August 14, 2019, Duke filed late-filed exhibits in response to questions from the Commission during the expert witness hearing.

On October 7, 2019, the Commission issued a Notice of Decision in this docket addressing issues relevant to the calculation of avoided capacity rates and avoided energy rates so that Duke and the Independent Administrator of the CPRE Program can calculate such rates; adjust implementation of the CPRE Program, as necessary; and proceed with the evaluation of proposals submitted in the Tranche 2 CPRE RFP Solicitation. The decisions announced therein are incorporated into this Order, including a discussion of the evidence supporting the findings and conclusions included in the Notice of Decision.

In its Notice of Decision, the Commission noted that issues related to the proposed integration services charge remained under consideration, and on October 17, 2019, the Commission issued a Supplemental Notice of Decision in this docket addressing such issues. The decisions announced therein are incorporated into this Order, including a discussion of the evidence supporting the findings and conclusions included in the Supplemental Notice of Decision.

On and after November 1, 2019, parties made various compliance filings associated with the Notice of Decision and Supplemental Notice of Decision, which will be decided by separate order.

In addition, on March 16, 2020, NCCEBA and NCSEA jointly filed Notice of Additional Authority providing a copy of the South Carolina Public Service Commission's avoided cost order, and on March 27, 2020, Duke filed a Response requesting the Commission to strike NCCEBA and NCSEA's filing. The Commission notes that it had reached its decisions in this docket but not yet finally reduced them to writing prior to NCCEBA and NCSEA's late filing, and that such filing played no part in the Commission's decisions announced in the Notice of Decision, Supplemental Notiec of Decision, or in this Order.

Based on the foregoing and the entire record herein, the Commission now makes the following

FINDINGS OF FACT

1. It is appropriate for DEC, DEP, and DENC to offer long-term levelized capacity payments and energy payments for ten-year periods as a standard option to all QFs contracting to sell one megawatt (MW) or less capacity. The standard levelized rate option of ten years should include a condition making the contracts under that option subject to renewal for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then-avoided cost rates and other relevant factors, or (2) set by arbitration.

2. It is appropriate for DEC, DEP, and DENC to be required to offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (1) participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded

as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term but shall instead change as determined by the Commission in the next biennial proceeding.

3. DENC should continue to offer in its Schedule 19-LMP, as an alternative to avoided cost rates derived using the Peaker Method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM Interconnection, LLC (PJM), subject to the same conditions as approved in the Commission's Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued on December 19, 2007, in Docket No. E-100, Sub 106 (2006 Sub 106 Order), except as modified by the Commission in its October 11, 2017 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued in Docket No. E-100, Sub 148 (2016 Sub 148 Order).

4. The proposed changes to DEC's and DEP's energy and capacity rate design, as indicated in the Rate Design Stipulation between Duke and the Public Staff, are appropriate for use in calculating DEC's and DEP's avoided energy and capacity rates in this proceeding.

5. The Rate Design Stipulation is the product of the give-and-take in settlement negotiations between Duke and the Public Staff, is material evidence in this proceeding, and is entitled to be given appropriate weight in this proceeding, along with the other record evidence.

6. DEC's proposed seasonal allocation weightings of 90% for winter and 10% for summer, and DEP's proposed seasonal allocation weighting of 100% for winter, are appropriate for use in weighting capacity value between winter and summer to calculate DEC's and DEP's avoided capacity rates in this proceeding.

7. Duke's assumptions regarding the availability of demand-side management (DSM) programs for reducing winter peak demand are appropriate for use in calculating avoided capacity costs in this proceeding, and it is appropriate to require Duke to place additional emphasis on defining and implementing cost-effective DSM programs that will be available to respond to winter demands.

8. It is appropriate to require DEC and DEP to continue to evaluate methods to better align their avoided cost rates with actual real-time system conditions to enable QFs to maximize their facilities' value to ratepayers through real-time pricing or other tariffs that provide more granular rate structures and price signals.

9. As a result of changes to the on- and off-peak hours being implemented in this Order, it is appropriate to waive the requirements of Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6) and to require an applicant for a certificate of public convenience and necessity (CPCN) to submit information regarding the projected annual production profile of the proposed generating facility, until such time as the Commission adopts revisions to the these Rules.

10. It is appropriate to consider amendments to the requirements of Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6) to include information regarding the annual energy production profile and other factors influencing the shape of the production profile in a generic proceeding.

11. The installed cost of a combustion turbine (CT) used by the Utilities, including the exclusion of hypothetical firm natural gas pipeline transportation capacity costs, is appropriate for use in calculating avoided capacity costs in this proceeding.

12. It is appropriate to require DEC, DEP, and DENC to include in their initial statements to be filed in the 2020 biennial avoided cost proceeding an evaluation and application of cost increments and decrements to the publicly available CT cost estimates, including the use of brownfield sites, existing infrastructure, decrements for electrical and natural gas connections, and other balance of plant items, to the extent it is likely that this existing infrastructure will be used to meet future capacity additions by the utility.

13. Power backflow on substations in DENC's North Carolina service territory from solar generation on the distribution grid continues to increase such that avoided line loss benefits associated with distributed generation have been reduced or negated.

14. It is appropriate for DENC not to include a line loss adder in its standard offer avoided cost payments to solar QFs on its distribution network.

15. It is appropriate to require DEC and DEP to continue to include the line loss adjustments in their standard offer avoided energy calculations, to study the effects of distributed generation on power flows on their electric systems to determine if there is sufficient power backflow at their substations to justify eliminating the line loss adjustment from their standard offer avoided cost calculations filed in the next avoided cost proceeding, and to evaluate whether power committed to be sold and delivered by distribution-connected QFs not eligible for the standard offer is causing power backflow on the substation and whether the line loss adjustment is appropriate based upon the characteristics of the individual QF's power.

16. It is appropriate to require DEC and DEP to utilize a performance adjustment factor (PAF) of 1.05 in their respective avoided cost calculations for all QFs, other than hydroelectric QFs without storage capability, and to utilize a PAF of 2.0 in their respective avoided cost calculations for hydroelectric QFs with no storage capability and no other type of generation until discontinued in accordance with the Hydro Stipulation.

17. It is appropriate to transition hydroelectric QFs currently selling the output of their facilities pursuant to the Hydro Stipulation to an applicable sales arrangement that is generally available to QFs, either the utility's standard offer contract or a negotiated contract, beginning December 31, 2020, and to require DEC and DEP to address issues related to this transition in their initial filings in the 2020 biennial avoided cost proceeding.

18. It is appropriate to require DEC and DEP to consider the use of other reliability indices, specifically the Equivalent Unplanned Outage Rate (EUOR) metric, to support

development of the PAF and to address this issue in its initial statement in the 2020 biennial avoided cost proceeding.

19. DEC, DEP, and DENC have complied with amended N.C.G.S. § 62-156(b)(3) and appropriately identified their first avoidable capacity need, as presented in their 2018 Integrated Resource Plans (IRPs).

20. For purposes of determining the first year of capacity need for negotiated contracts and for Competitive Procurement of Renewable Energy (CPRE) Tranche 2, it is appropriate for a utility to update its avoided capacity calculations to reflect any changes in the utility's first year of avoidable capacity need.

21. There is insufficient evidence in this record for the Commission to find that any utility uprates shown in DEC's or DEP's most recent IRPs are deferrable or avoidable for purposes of establishing a capacity rate; therefore, these uprates shall not be included in the determination of avoided capacity costs for purposes of this proceeding.

22. Beginning with the 2020 IRPs, the Utilities shall include a specific statement addressing the utility's future capacity needs to be used to determine the first year of avoidable capacity need in the next biennial avoided cost proceeding.

23. It is appropriate for the Utilities to recognize that a swine or poultry waste generator, or a hydroelectric facility 5 MW or less in capacity that has a power purchase agreement in effect as of July 27, 2017, which commits to sell and deliver energy and capacity for a new fixed-term contract prior to the termination of the QF's existing contract term is avoiding the Utilities' future capacity need for these designated resource types beginning in the first year following expiration of the QF's existing PPA, pursuant to the N.C.G.S. § 62-156(b)(3), as amended in House Bill 329.

24. For other types of QF generation, it is appropriate under PURPA and consistent with N.C.G.S. § 62-156(b)(3) for the Utilities to recognize a QF's commitment to sell and deliver energy and capacity over a future fixed term as avoiding an undesignated future capacity need beginning only in the first year when there is an avoidable capacity need identified in DEC's, DEP's, or DENC's most recent IRPs.

25. It is appropriate for DEC, DEP, and DENC to continue their current approach to the assumed January 2019 in-service date for the purposes of this proceeding.

26. It is appropriate for the utility and a QF not eligible for the standard offer contract to negotiate a presumed in-service date for rate calculation purposes accounting for any anticipated date of the QF project coming online.

27. It is appropriate to require DEC and DEP to continue to calculate their avoided energy costs using forward natural gas prices for no more than eight years before using fundamental forecast data for the remainder of the planning period, and to authorize DENC to use

its proposed fuel forecasting methodology in calculating its avoided energy costs for the purposes of this proceeding.

28. It is appropriate to require DEC and DEP to recalculate their avoided energy costs to include the value of their current hedging programs using the Black-Scholes Model or a similar method that values the added fuel price stability gained through each year of the entire term of the QF power purchase agreement.

29. There is insufficient evidence in this record for the Commission to find that the rates established for DEC or DEP should include an avoided distribution capacity cost adder applicable to all distribution- or transmission-connected QFs for the purposes of this proceeding.

30. It is inappropriate to require DEC or DEP to use avoided transmission and distribution (T&D) capacity rates from the demand-side management/energy efficiency proceedings in calculating avoided T&D capacity costs for the purposes of this proceeding.

31. It is appropriate to require DEC and DEP to consider site- and project-specific characteristics during contract negotiations with QFs not eligible for the standard offer contract, and to include an avoided T&D capacity adder if a project can provide real and measurable avoided transmission capacity benefits.

32. It is inappropriate to require DEC or DEP to include an "adder" for avoided energy costs based upon a generalized assumption that the integration of uncontrolled solar QF generating capacity, in the aggregate, suppresses or reduces prices in the wholesale power market.

33. DEC and DEP are incurring increased intra-hour ancillary services costs to integrate the "Existing plus Transition" level of solar QFs into the DEC and DEP systems, and it is appropriate to require DEC and DEP to account for these costs when calculating the costs and benefits resulting from the purchase of energy and capacity from solar QFs.

34. The determinations based upon the results of the Astrapé Study demonstrate that an additional 26 MW of load following reserves are required to integrate 840 MW of solar-QF capacity in DEC at an average cost of $1.10/MWh and that an additional 166 MW of load following reserves are required to integrate 2,950 MW of solar-QF capacity in DEP at an average cost of $2.39/MWh, and are reasonable for use in this proceeding.

35. It is appropriate for Duke to apply prospectively the integration services charge to all new uncontrolled solar generators that commit to sell and deliver power into the DEC and DEP systems on or after November 1, 2018.

36. It is appropriate to apply the integration services charge as a fixed amount of $1.10/MWh for DEC and $2.39/MWh for DEP during the term of the contracts for those QFs that establish a LEO during the availability of the rates established in this proceeding as a decrement to and included in DEC's and DEP's respective avoided energy rates.

37. It is inappropriate for DEC or DEP to impose the integration services charge on QFs that qualify as "controlled solar generators" by demonstrating that their facility is capable of operating, and by contractually agreeing to operate, in a manner that materially reduces or eliminates the need for additional load following reserves required to integrate solar-QF capacity.

38. It is appropriate to require DEC and DEP to file with the Commission proposed guidelines for QFs to become "controlled solar generators" and thereby avoid the integration services charge.

39. The SISC Stipulation between Duke and the Public Staff is the product of the give-and-take in settlement negotiations between the Duke and the Public Staff, is material evidence in this proceeding, and is entitled to be given appropriate weight in this proceeding, to the extent that those agreements are consistent with state and federal law.

40. The Astrapé Study methodology used to quantify DEC's and DEP's increased ancillary services costs and to calculate each utility's integration services charge presents novel and complex issues that warrant further consideration.

41. It is appropriate to require DEC and DEP to calculate avoided energy rates that do not include an integration services charge and to include these rates that would be available to "controlled solar generators" as a part of the tariffs and standard contracts in this proceeding.

42. It is appropriate to require DEC and DEP to submit the Astrapé Study methodology to an independent technical review and to include the results of that review and any revisions to the methodology that is supported by the results of that review in its initial filing in the 2020 biennial avoided cost proceeding.

43. The proposed changes to DENC's energy and capacity rate design are appropriate to send better price signals to incent QFs to better match DENC's system generation needs, and it is appropriate to require the use of this rate design in calculating DENC's avoided energy and capacity rates in this proceeding.

44. DENC's revised proposed seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons are appropriate for use in this proceeding.

45. DENC's proposed input assumptions to be used in determining its proposed avoided energy costs, including those related to fuel hedging activities and the LMP adjustment, are appropriate for use in this proceeding.

46. DENC's proposed re-dispatch charge of $0.78/MWh is reasonable for use in this proceeding as an appropriate mechanism to recover costs incurred by DENC to integrate intermittent, non-dispatchable QFs in its service territory.

47. It is inappropriate to authorize the use of DENC's proposed annual capacity payment cap for the purpose of calculating rates in this proceeding.

48. It is appropriate to require DENC to utilize a PAF of 1.07 in its avoided cost calculations for all QFs.

49. The proposed modifications to the Standard Terms and Conditions proposed by Duke, including the definition of Material Alteration, are reasonable and appropriate. In determining whether updates to a facility are a Material Alteration that would lead to the termination of the existing PPA, Duke should evaluate those changes in a commercially reasonable manner and with a "degree of reasonableness" regarding any increase in capacity that results from equipment replacement and repairs.

50. Prior to increasing their output consistent with the Terms and Conditions of their existing PPAs, "Committed" solar QFs (i.e., facilities that have (i) established a legally enforceable obligation (LEO); (ii) executed a PPA; or (iii) commenced operation and sale of the electric output of the facility) that seek to add storage or otherwise materially increase their output by re-paneling or over-paneling should obtain the utility's consent, contingent on an evaluation of the potential impacts to the utility's system or other customers.

51. Material alterations to committed facilities that increase a utility's obligations to purchase energy at prior avoided cost rates are inappropriate and would unfairly burden ratepayers with increased payments to QFs that exceed current avoided cost rates. However, it is premature at this time to determine whether the Public Staff's compromise position that existing solar facilities that add storage by co-locating a battery behind the meter should be compensated at the current avoided cost rates is appropriate.

52. It is appropriate for the parties to continue to discuss the technical, regulatory, and contractual complexities of separately metering the energy output from energy storage equipment that is co-located at existing solar facilities for further consideration by the Commission.

53. It is appropriate to require WCU and New River to offer to all QFs contracting to sell 1 MW or less variable rates based upon their wholesale cost of power and to offer long-term fixed price rates that track DEC's Commission-approved ten-year term standard offer.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 – 3

The evidence supporting these findings of fact is found in Duke's verified Joint Initial Statement filed on behalf of DEC and DEP and the exhibits attached thereto (Duke's verified JIS) and DENC's verified Initial Statement and the exhibits attached thereto (DENC's verified Initial Statement). These findings are essentially jurisdictional and administrative and are not contested.

Summary of the Evidence

In its JIS Duke filed updated standard offer avoided cost rates available to all QFs that meet the eligibility requirements set forth in DEC's and DEP's respective Schedule PPs and that establish a LEO committing to sell the output of their QF generating facility to DEC or DEP on or after November 1, 2018, but prior to the initial filing in the next biennial avoided cost proceeding. As provided in these schedules:

> In order to be an Eligible Qualifying Facility and receive Energy Credits under this Schedule, the Qualifying Facility must be a hydroelectric or a generator fueled by trash or methane derived from landfills, solar, wind, hog or poultry waste-fueled or non-animal biomass-fueled Qualifying Facility with a Contract Capacity of one (1) megawatt or less, based on the nameplate rating of the generator(s), which are interconnected directly with the Company's system and which are Qualifying Facilities as defined by the Federal Energy Regulatory Commission pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978.

Duke further states that pursuant to N.C.G.S. § 62-156(b)(3), electric generation fueled by swine waste and poultry waste may be eligible for a different avoided capacity rate "if Seller sells the output of its facility, including renewable energy credits," to Duke for compliance with the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) requirements set forth in N.C.G.S. § 62-133.8(e) and (f). JIS at 1; JIS DEC Exhibit 1 and DEP Exhibit 1.

Along with its Initial Statement DENC filed Schedule 19-FP and Schedule 19-LMP, to be available to any QF eligible for these tariffs that has (a) submitted to the Commission a report of proposed construction pursuant to N.C.G.S. § 62-110.1(g) and Rule R8-65, (b) submitted to the Company an Interconnection Request pursuant to Section 2 or Section 3 of the North Carolina Interconnection Procedures (NCIP), and (c) submitted to the Company a duly executed "Notice of Commitment to Sell the Output of a Qualifying Facility of No Greater Than 1 Megawatt Maximum Capacity to Dominion Energy North Carolina" by no later than the date on which proposed rates are filed in the next biennial avoided cost proceeding.

In its Initial Statement DENC proposes to continue to offer Schedule 19-LMP to QFs as an alternative to its Schedule 19-FP, which provides for payment for delivered energy and capacity at the avoided cost rates determined by the Commission. Under Schedule 19-LMP, DENC would pay a QF for delivered energy and capacity an equivalent amount to what it would have paid PJM if the QF generator had not been generating. The avoided energy rates paid to the larger QFs with a design capacity of greater than 10 kilowatts (kW) would be the PJM Dominion Zone Day-Ahead hourly locational marginal prices (LMPs) divided by 10, and multiplied by the QF's hourly generation, while the smaller QFs that elect to supply energy only would be paid the average of the PJM Dominion Zone Day-Ahead hourly LMPs for the month as shown on the PJM website. Capacity credits would be paid on a cents per kilowatt-hour (kWh) rate for the 16 on-peak daily hours (7 a.m. to 11 p.m.) for all days. DENC used the PJM Reliability Pricing Model (RPM) to determine its avoided capacity costs shown as the prices per megawatt per day from PJM's Base Residual Auction for the Dom Zone. As in prior proceedings, DENC also adjusted the avoided capacity rate using a Summer Peak Performance Factor (SPPF) as an incentive for QFs to operate during PJM system peak days. The calculation of the SPPF incorporated historical operational data on five individual days during the prior year's summer peak season (defined by PJM as the period from June 1 through September 30). The SPPF varies based on the QF's prior year's operations. DENC's verified Initial Statement at 13, Exhibit DENC-3 at 5.

In its Initial Comments the Public Staff reviews and summarizes the rate schedules proposed by the Utilities but does not recommend any changes to the standard offer term and eligibility thresholds proposed by the Utilities.

No party proposes changes to the standard offer term and eligibility thresholds or otherwise raised objections to the approval of the Utilities' proposed schedules with respect to these issues.

Discussion and Conclusions

In the 2016 Sub 148 Order, the Commission approved changes to the standard offer term and eligibility thresholds as a result of changes in the marketplace for QF-supplied power in North Carolina and as a result of the amendments to N.C.G.S. § 62-156 enacted through S.L. 2017-192. The Commission noted that these changes were appropriate to

> reflect a comprehensive effort to modify the State's avoided cost policies towards a model that is more efficient and sustainable over the long term, while at the same time providing protection to ratepayers from overpayment risk and certainty to QFs.

2016 Sub 148 Order at 38. The Commission further indicated that it would "continue to monitor the amount of actual QF development and the stability of avoided cost rates to ensure that ratepayers are not exposed to undue risk of overpayments, while at the same time providing QFs with an opportunity to obtain financing on reasonable terms." *Id.* at 23.

Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate to require the Utilities to continue to offer as a standard option long-term levelized capacity payments and energy payments for ten-year periods to all QFs contracting to sell 1 MW or less capacity.

In past biennial avoided cost proceedings the Commission ruled that, absent an approved, active solicitation, negotiations between a utility and a larger QF are subject to arbitration by the Commission at the request of either the utility or the QF to determine the utility's actual avoided cost, including both capacity and energy components, as appropriate, as long as the QF is willing to commit its capacity for a period of at least two years. Such arbitration would be less time consuming and expensive for the QF than the previously utilized complaint process. The Commission concludes that the arbitration option should be preserved. Therefore, the Utilities shall offer QFs not eligible for the standard long-term levelized rates the following three options: (1) if the utility has a Commission-recognized active solicitation, participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term but shall instead change as determined by the

Commission in the next biennial proceeding. The Commission again recognizes the enactment of N.C.G.S. § 62-110.8, providing for a competitive procurement option for renewable energy facilities. *See* 2016 Sub 148 Order at 38-39. To date, the Commission has not received a motion, nor issued an order, addressing the exact points when an active solicitation shall be regarded as beginning or ending nor addressed whether the CPRE program may be considered an active solicitation for PURPA compliance purposes. Accordingly, it is appropriate for the arbitration option to remain available for issues arising during negotiations between a utility and QF.

The Commission further finds, based upon the foregoing and the entire record herein, that it is appropriate for DENC to continue to offer, that as an alternative to avoided cost rates derived using the Peaker Method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM, including the payment of capacity credits based on the PJM RPM, are appropriate subject to the same conditions as approved in the 2006 Sub 106 Order and most recently restated in the 2016 Sub 148 Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 – 8

The evidence supporting these findings of fact is found in Duke's verified JIS and in the testimony of Duke witnesses Snider and Wheeler, NCSEA witness Johnson, SACE witness Wilson, and Public Staff witness Thomas.

Summary of the Evidence

In its JIS Duke states its Schedule PP pays QFs on a volumetric rate basis (i.e., both avoided energy and capacity are paid on a $/MWh basis versus a separate fixed payment for capacity), and the rates are designed to credit QFs for avoided energy supplied during predesignated on-peak and off-peak hours. Payments for avoided energy are applicable to all QF energy supplied during the year and vary for the designated on-peak and off-peak hours in a day. Payments for avoided capacity are applicable to all QF energy supplied during the designated capacity payment hours.

In the 2016 Sub 148 Order the Commission observed that "avoided capacity calculations could send better price signals to incentivize QFs to better match the generation needs of utilities." The Commission therefore required the Utilities to consider refinements to the avoided capacity calculation and to address these refinements in the Sub 158 proceeding. 2016 Sub 148 Order at 56. The Commission directed the Utilities to consider "a rate-scheme that pays higher capacity payments during fewer peak-period hours to QFs that provide intermittent, non-dispatchable power, based on each utility's costs during the critical peak demand periods." *Id.* In this proceeding, the Commission similarly directed the Utilities to "file proposed rate schedules that reflect each utility's highest production cost hours, as well as summer and non-summer peak periods, with more granularity than the current Option A and Option B rate schedules." 2018 Scheduling Order at 1-2.

In response to the Commission's directives Duke proposes changes to its Schedule PP to eliminate the pre-existing Option A and Option B hours and to develop updated, more granular rate designs that better recognized the value of QF energy and capacity. JIS at 27. Duke's initially proposed Schedule PP rate structure for energy payments defines the summer period as May through September and the non-summer period as October through April. The energy pricing includes five distinct pricing periods, each of which has an independent price block to better reflect the value of QF energy during the different periods. Each utility defines its energy pricing hours separately to account for the differences in each utility's load profile net of solar generation.

For capacity, Duke's initially proposed updated Schedule PP capacity pricing period consists of six months with summer defined as July and August and winter defined as December through March. *Id.* at 28. The capacity pricing is comprised of three pricing periods which include defined evening hours in the summer, and morning and evening hours in the winter.

Duke's initial proposal to update the Schedule PP rate design for energy and capacity reflects more narrowly defined seasons and hours compared to the former Option A and B definitions, and higher energy payments during Duke's highest production cost hours and capacity payments only in hours with high loss of load risk. The new rate design also reflects changes to the seasonal allocation weighting for capacity payments. The new seasonal allocation is more heavily weighted to winter than the prior allocation based on the impact of summer versus winter loss of load risk. As presented in Duke's 2018 IRPs, 100% of DEP's loss of load risk occurs in the winter, and approximately 90% of DEC's loss of load risk occurs in the winter. Thus, DEP's new rates pay all of its annual capacity value in the winter, and DEC's new rates pay 90% of its annual capacity value in the winter and 10% in the summer period. *Id.* at 29.

In its Initial Comments NCSEA states that Duke's proposed allocations are inappropriate due to flaws in the loss of load analysis that underlies the proposed allocations, underestimates of winter DSM assumptions, a failure to consider imports, and flawed solar modeling. NCSEA recommends that the Commission instead require Duke to utilize the allocation ratios previously approved by the Commission in the 2016 Sub 148 Order. NCSEA Initial Comments at 13-14. NCSEA further recommends that Duke provide granular rate schedules that incorporate geographic granularity. NCSEA notes that without such geographic granularity, there is no incentive for QFs to locate in areas where transmission and distribution costs can be avoided. *Id.* at 26-27. NCSEA further states that the Utilities failed to adequately recognize how costs vary by seasons and that Duke's proposal not to differentiate a winter season did not appropriately consider the different patterns of electrical usage, net system load, marginal production costs, and avoided costs that occur during winter as opposed to spring and summer. NCSEA also states that the Utilities did not adequately recognize how costs vary across different times of day, despite having access to detailed avoided cost data for all 8,760 hours for the next ten years. NCSEA proposes that instead of the Utilities' proposals, the Commission should adopt the time-of-day periods it proposes, as well as an optional real-time pricing tariff for QFs. *Id.* at 28. NCSEA witness Johnson supports this proposal by detailing the following specific energy rate design schedules: (i) a 12 month by 24 hour rate design (12x24 Design), and (ii) a fixed tariff with a set number of real time pricing (RTP) high and low cost hours (Hybrid Tariff), both of which would provide additional granularity to avoided energy rates. Johnson Affidavit at 64-76.

In its Initial Comments SACE also argues that Duke's proposal to allocate all or nearly all loss of load risk in the winter devalues the capacity contributions of solar QFs and almost completely eliminates consideration of the capacity benefits solar QFs provide during summer demand peaks. SACE provided the Report on the Resource Adequacy Studies and Capacity Value

Study prepared by James F. Wilson (Wilson Report), which raised the following four concerns: (1) the representation of winter loads under extreme cold conditions, based on an extrapolation of the relationship between very cold temperatures and winter loads; (2) the "economic load forecast uncertainty" layered on top of the weather-related load distributions; (3) the assumptions regarding future winter demand response capacity; and (4) the assumptions regarding operating reserves during brief load spikes on extremely cold winter mornings. SACE Initial Comments at 11-12.

SACE further argues that Duke's rate design contained several methodological flaws, which combined with the above-listed concerns result in Duke greatly overstating DEC's and DEP's winter resource adequacy risk compared to summer, and inappropriately allocating 100% and 90% of winter loss of load risk in DEP and DEC, respectively. Witness Wilson testified that these shortcomings also directly impact Duke's proposed avoided capacity rate designs for Schedule PP, which are derived from the same flawed analysis, and that the Commission should require Duke to re-calculate and file revised avoided capacity rates and rate designs. *Id.* at 13.

In its Initial Comments the Public Staff states that the pricing periods proposed in this proceeding are an improvement over the current Option B hours in terms of being reflective of historical marginal energy costs. Nevertheless, the Public Staff believes that energy rate mismatches were still likely and could result in QFs potentially being over- or under-paid for the energy generated. As a result, the Public Staff proposes its own seasonal energy rates and hours:

> The Public Staff's proposed seasonal energy rates and hours were developed with a basic core premise: that, to the extent possible, avoided energy costs should reflect each utility's actual avoided production cost. Using this guiding principle, the avoided cost hours and rates then provide price signals to QF developers that will increase each QF's relative value to the grid and, ultimately, to ratepayers. For example, more granular pricing would signal a dispatchable QF to provide energy during times when the Utilities are most likely to operate their highest marginal cost generation units, thus avoiding the need to run those units, and would also provide clear price signals to developers interested in adding new technologies, such as energy storage, to their intermittent facilities. Avoided energy rates that accurately reflect the Utilities' highest production cost hours (lambdas) increase the likelihood that the interests of ratepayers and developers align.

Public Staff Initial Comments at 54.

With regard to capacity, the Public Staff also raises concerns regarding the Resource Adequacy Studies that Duke used, including the assumptions made regarding the relationship between cold weather and load, estimates of load forecast error distributions, and a lack of recognition of winter hardening efforts undertaken by the utilities, among others. Because of these concerns, the Public Staff recommends that the Commission direct Duke to rerun the Resource Adequacy Studies using the Public Staff Scenario #2 (PS-S2) that was analyzed by Duke in the 2018 IRP proceeding to determine the effect of the Public Staff's proposed modifications on the capacity payment hours and seasonal allocation. *Id.* at 58-59.

In its Reply Comments Duke states that as a result of further discussions between Duke, Astrapé, and the Public Staff, the Public Staff now concurs with Duke's proposal and accepts that the alternative PS-S2 scenario would not have a material impact on the seasonal allocation weightings or capacity payment hour designations. Duke Reply Comments at 61. Regarding the concerns raised by SACE over the methodology Duke used to capture the relationship between winter load and cold temperatures, Duke states that it performed a sensitivity analysis that reduced the regression equations significantly for temperatures below the levels seen in recent years, and it resulted in a small decrease (0.33%) in the reserve margin. Duke recommends that the Commission reject the concerns raised by witness Wilson on this topic. *Id.* at 62.

Similarly, with regard to the claims raised by witness Wilson that the 2016 Resource Adequacy studies exaggerate winter risk through the operating reserve assumptions, Duke indicates that witness Wilson's statements regarding the operating reserves that are held back in the Strategic Energy Risk Valuation Model (SERVM) model are inaccurate, and therefore should be rejected. *Id.* at 62-63.

Regarding the claims raised by NCSEA and SACE that winter DSM programs are a reasonable tool for reducing winter peak demand, when available, Duke agrees with these assessments. Duke states, however, that the levels of reduction proposed by NCSEA and characterized by NCSEA witness Johnson as "conservative," are actually extremely optimistic and not reasonably achievable in the timeframe proposed, if at all. *Id.* at 33. Duke states that NCSEA fails to accurately support its proposal, and notes that some of the comparisons drawn by NCSEA are flawed and fail to recognize differences between utilities including climate, residential and commercial water and space heating sources, industrial demand, and avoided costs. In addition, Duke notes that winter DSM programs raise different challenges than summer programs. Duke notes that it plans to continue to implement new winter DSM programs as proposed in DEC's and DEP's 2018 IRPs, but the amount proposed by NCSEA is not supported and cannot be prudently included in the IRP forecast. Therefore, Duke recommends that the Commission reject NCSEA's claim and accept Duke's seasonal allocation as reasonable and appropriate for purposes of inclusion in the avoided capacity rate. *Id.* at 66. Duke further notes that as a result of on-going discussions with the Public Staff and other parties, and to better align the winter capacity season with energy payment hours, Duke proposes to redefine the winter capacity season as December through February. *Id.* at 66.

Regarding its energy rate design Duke states that it generally does not oppose the Public Staff's objective of providing more granular rates with greater rate differentiations and concurs with the Public Staff's proposal to use an objective rate design methodology to establish rate periods that better reflect cost causation principles. As a result, Duke proposed a modified Schedule PP energy rate design following a three-step process similar to that originally proposed by the Public Staff, but with the concept of a more flexible design that considers the practicality of the design which enhances customer acceptance and compliance with the intended price signals. *Id.* at 69. In the updated energy rate design, the season definitions would be expanded to include Summer, Winter, and Shoulder seasons as compared to Duke's initial proposal which included Summer and Non-Summer only. Second, the newly proposed Winter season would be defined to include December, January, and February. Third, the concept of higher-priced rating periods, called Premium Peak hours, would be included during the Winter and Summer seasons, similar to the Public Staff's original proposal, but with slightly expanded premium peak windows during each peak day. *Id.* at 70-71.

In response to NCSEA's recommendation that Duke introduce geographic price signals and develop hosting capacity maps, Duke states that: (1) requiring the Utilities to incur increased costs to develop hosting capacity maps is neither appropriate under PURPA nor cost beneficial, particularly in the context of the standard offer framework; (2) hosting maps have already been considered by the parties in the context of the interconnection proceeding in Docket No. E-100, Sub 101, in which the Public Staff indicates that the benefits associated with developing distribution level hosting capacity maps was outweighed by their costs; and (3) the information provided in the hosting capacity maps would be static and not adequately recognize the Utilities' capability to reconfigure the distribution grid to shift load and generation across distribution circuits to achieve a better balance, resulting in changes in the cost/benefit of having generation on a specific circuit. As a result, Duke argues that non-geographic specific pricing offers a fair rate to all generators committing to sell under the standard offer tariff and allows Duke to adjust system line loadings to maximize benefits for all customers, and that NCSEA's recommendation therefore should be rejected. *Id.* at 73-74.

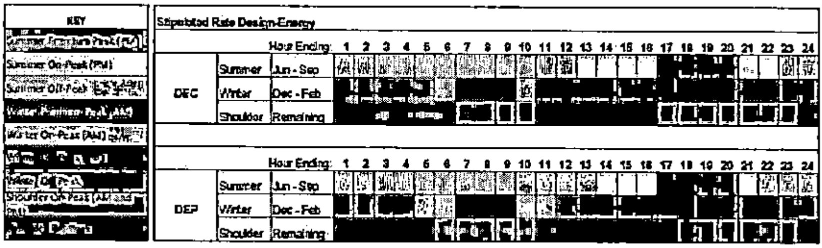
With regard to NCSEA's time-of-day pricing periods and optional real-time pricing tariffs, Duke agrees that this information could help align actual avoided costs to QF payments, but that the granular pricing periods proposed in this proceeding are sufficient at this time. Duke further agrees to continue to investigate development of time-of-day and real-time pricing periods for standard offer QFs but recommends that the Commission accept the updated avoided cost rate design as reasonable and appropriate. *Id.* at 74-75.

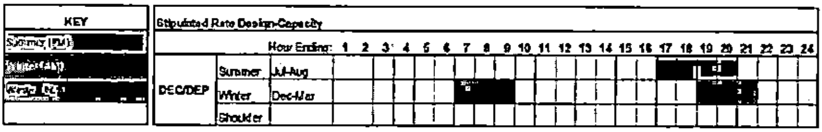
In response to NCSEA's proposed rate design changes, the Public Staff in its Reply Comments states that hourly pricing for each month, as proposed in the 12x24 Design, could provide benefits to ratepayers and send appropriate price signals to QFs. However, the Public Staff notes that because some months have similar energy price characteristics, this approach may increase complexity without providing significant additional benefits. Instead, focusing on three seasons, each with multiple pricing tiers, would provide more granular pricing information to QFs without imposing significant new administrative burdens. Public Staff Reply Comments at 3.

The Public Staff also indicates that it supports the availability of an RTP tariff for avoided energy, which could enable QFs to maximize their facilities' value to customers, particularly in light of innovative technologies such as energy storage, while minimizing the risk of over- and under-payments for energy. The Public Staff recommends that DEC and DEP offer an RTP avoided cost tariff as an optional alternative to their proposed Schedule PP in the next avoided cost filing. *Id.* at 7.

Duke witness Snider testified that the Rate Design Stipulation was the result of the parties attempting to resolve their differences regarding different rate design alternatives. The stipulated rate design, as indicated in Snider Figure No. 2 reproduced below, is similar to the Public Staff's original three-step rate design approach and identifies the energy and capacity periods that best reflect each utility's avoided cost based upon seasonal and time-of-day characteristics. Tr. vol. 2, 65.

Snider Figure 2: Stipulated Energy and Capacity Rate Periods (By Hour)





In support of the Rate Design Stipulation, Duke witness Snider testified that the updated rate designs reasonably and accurately reflect the avoided cost value of QF energy and capacity being delivered to Duke and paid for by customers, explaining that the proposed rate design contained in the Rate Design Stipulation will also provide strong price signals to QFs by identifying the times that generation is of the most value to customers and providing a financial incentive to maximize their generation during these higher production cost hours. Thus, he testified that the rate design encourages QFs to configure their operating scheme to take advantage of these higher rate periods when energy and capacity are of the highest value to customers. Tr. vol. 2, 29.

Witness Snider also testified in response to SACE witness Wilson's argument that the stipulated avoided capacity rate design focuses on too narrow periods of time, stating that the stipulated rate design is consistent with the Commission's direction in the 2016 Sub 148 Order in that it provides for higher capacity payments during fewer peak-period hours to QFs that provide intermittent, non-dispatchable power, based on each utility's costs during critical peak demand periods. In addition, he argues that the stipulated rate design is consistent with the Commission's 2018 Scheduling Order in that it also reflects Duke's highest production cost hours with more granularity than under prior rate schedules. Tr. vol. 2, 76, 115.

Witness Snider also responded to NCSEA witness Johnson's recommendation that the Utilities calculate different rates for each hour of the month, explaining that this proposal would tend to lock in price differences and price relationships between the hours in a manner that would likely not coincide with actual real-time system conditions, particularly over time, and also unnecessarily increase billing complication, thereby increasing the risk of billing errors. In addition, regarding witness Johnson's RTP pricing proposal, witness Snider testified that the proposal does not appear to support a true RTP rate similar to DENC's LMP tariff during all hours, but instead appears to call for RTP rates during times when costs to serve are high, and a guaranteed forecasted average cost rate during all other hours, including hours when the cost to serve is lower than the average avoided cost rate. Witness Snider stated that such an approach would be inconsistent with the FERC's general implementation of PURPA, which provides that a QF may elect to commit to deliver its power at the utility's avoided cost either calculated at the time of delivery or calculated at the time the QF makes its legally enforceable commitment to deliver energy and capacity. Witness Snider noted that Duke would be agreeable to investigating development of RTP periods for standard offer QFs that do not require the financial assurance of a fixed rate and instead are willing to accept rates calculated at the time of delivery, based upon Duke's actual hourly marginal cost of energy. Tr. vol. 2, 116-18. Witness Snider also testified that for the same reasons stated in Duke's Reply Comments, the Commission should reject NCSEA's recommendation that Duke offer geographically differentiated avoided cost rates. Tr. vol. 2, 119-20.

In response to NCSEA witness Johnson's argument that an assessment of historical loads does not support a seasonal allocation heavily weighted to winter, witness Snider testified that NCSEA's criticisms are essentially the same arguments that were made in the 2016 Sub 148 Proceeding and ignore the impact of continued increases in the amount of must-take solar generation on the utilities' loss of load risk. Witness Snider noted that the Commission in its 2016 Sub 148 Order rejected the arguments raised by NCSEA and instead recognized the significant impact that high penetrations of solar were having on summer versus winter loads net of solar contribution. Witness Snider also noted that Duke has seen significant cold weather load responses in recent years in excess of summer conditions that were not fully considered in NCSEA witness Johnson's review period. Witness Snider concluded that an assessment of historic loads without consideration of the impact of current and projected levels of must-take solar output does not provide meaningful insights into the appropriate seasonal allocation weightings. Tr. vol. 2, 122-26.

In response to SACE witness Wilson's criticisms of Duke's reliance on its 2016 Resource Adequacy Study for purposes of determining seasonal allocation capacity payments, witness Snider stated that the Commission found in its 2016 Sub 148 Order that it was appropriate to rely on the Resourec Adequacy Study for purposes of establishing seasonal allocation of capacity payments. Witness Snider further noted that the use of the loss of load risk values as allocation factors appropriately represents the seasonal capacity benefit provided by a QF, and properly aligns with cost causation principles. Witness Snider also noted that Duke and the Public Staff agree that it is appropriate that the resource adequacy studies, along with all inputs and modeling assumptions, should be updated for use in the 2020 biennial IRP filings. Tr. vol. 2, 127-30.

In response to NCSEA witness Johnson's suggestion that Duke's seasonal allocation is inconsistent with PURPA, in that QFs are not being fully compensated for the capacity costs they enable the utilities to avoid, Duke witness Snider testified that Duke's IRP planning methodology and approach to recognizing future capacity needs based upon future loss of load expectation (LOLE) is consistent with the general principles of PURPA and is technologically agnostic. He stated that non-dispatchable QFs therefore are being fully compensated for the capacity value they provide. In addition, witness Snider argued that Dukes' methodology is fully consistent with N.C.G.S. § 62-156(b)(3), which provides that:

> A future capacity need shall only be avoided in a year where the utility's most recent biennial integrated resource plan filed with the Commission pursuant to [N.C.G.S.

§] 62-110.1(c) has identified a projected capacity need to serve system load and the identified need can be met by the type of small power producer resource based upon its availability and reliability of power . . . .

Witness Snider testified that Duke's seasonal allocation may continue to change over time as customer mix, customer energy usage, and changes to the summer and winter resource mix, including the continued addition of solar resources, the addition of battery storage capability, longer-term potential wind resources, additional DSM programs or other changes impacting the balance of summer versus winter resources, and other factors change. As these changes occur, Duke will update these seasonal allocations as appropriate in future biennial proceedings. Tr. vol. 2, 133-35.

Public Staff witness Thomas testified that the Public Staff largely agrees with Duke's proposed capacity payment hours and seasonal allocation and did not propose any significant changes to the capacity rate design. He testified that to prevent overpayment to QFs for capacity that is not needed, it is most appropriate to pay capacity payments only during hours where there is a loss of load risk. Finally, witness Thomas testified that Duke's use of the LOLE metric is reasonable and protects ratepayers from overpaying for QF capacity, and that the proposed rate design sends the appropriate price signals to QFs. Tr. vol. 6, 389-91.

Discussion and Conclusions

Avoided Energy Rates

In the 2018 Scheduling Order the Commission directed Duke to address in its initial filings in this proceeding, among other issues, consideration of a rate design that considers factors relevant to the characteristics of QF-supplied power that is intermittent and non-dispatchable. 2018 Scheduling Order at 1. More specifically, and consistent with the discussion and conclusions reached in the Commission's 2016 Sub 148 Order, the Commission expressed its expectation that Duke would file proposed rate schedules that reflect each utility's highest production cost hours, as well as summer and non-summer periods, with more granularity than the current Option A and Option B rate schedules historically used in the implementation of PURPA and N.C.G.S. § 62-156.

As summarized above Duke responded to this direction through its initial filing, and the Public Staff conducted an extensive investigation as to the reasonableness of Duke's proposed rate design. The product of that investigation was filed with the Commission in this docket as the Rate Design Stipulation. Based upon the foregoing and the entire record herein, the Commission finds that the Rate Design Stipulation is the product of give-and-take in negotiations between Duke and the Public Staff and that along with the testimony in support of the Rate Design Stipulation, is entitled to appropriate weight in this proceeding.

For the following reasons the Commission gives substantial weight to the Rate Design Stipulation and the testimony in support thereof and finds that the proposed changes to DEC and DEP's energy rate design as indicated in the Rate Design Stipulation are appropriate for use in calculating energy rates in this proceeding. First, the Commission finds merit in the general approach utilized by the Public Staff to develop granular pricing methods for avoided energy that more accurately reflect Duke's highest production cost hours and loads to increase the likelihood that the interests of ratepayers and developers of QF generators align. The Rate Design Stipulation reflects an agreement between the Public Staff and Duke on more granular pricing methods consistent with the Public Staff's approach. Second, the Commission determines that the modifications made through discussions between the Public Staff and Duke to further refine this rate design approach, as memorialized in the Rate Design Stipulation, strike an appropriate balance between accurate avoided cost pricing, administrative efficiency, and the general acknowledgment that these factors will continue to change over time. Third, the stipulated rate design was the result of a methodological approach to evaluate system costs and impacts as described in the Rate Design Stipulation, and properly aligns price signals provided in the rate design with Duke's avoided energy costs.

With regard to NCSEA's proposal to develop more geographically granular rates, the Commission finds that there is insufficient evidence demonstrating that such an effort is appropriate for the standard offer tariff or would be cost beneficial at this time. After carefully considering NCSEA's evidence and arguments on this issue, the Commission is not persuaded that the benefits associated with developing detailed geographic guidance for smaller generating facilities seeking to select suitable interconnection locations will outweigh the costs when similar information is already made available through other interconnection processes such as the Section 1.3 Pre-Application Reports.[1] Further, as Duke witness Snider testified, utilities are constantly reconfiguring their distribution grid to better balance load and generation, and as a result, the information for a specific circuit may be dynamic in nature. Lastly, the administrative efficiency of providing non-geographically differentiated standard offer pricing must also be considered in light of the fact that the standard offer tariff is an optional tariff intended to be generically available to small QFs pursuant to 18 C.F.R. § 292.304(c) and N.C.G.S. § 62-156(b), and is limited to small power producer QFs with a design capacity up to 1 MW pursuant to N.C.G.S. § 62-156(b).[2] Any QF that seeks to introduce "individual characteristics of the small power producer," such as geographic location, that the QF believes may impact the "individual . . . value of energy and capacity from [the QF] on the electric utility's system" may do so in negotiating avoided cost rates based upon the specific costs that it allows the utility to avoid under N.C.G.S. § 62-156(c) and 18 C.F.R. § 292.304(e)(2)(vi). As such, the Commission determines that geographically granular rates should not be required for standard offer facilities in this proceeding.

Regarding the proposal by NCSEA to require the Utilities to provide 24 different hourly rates each day, the Commission agrees with Duke that offering such specific hourly rates would lock in price differences and price relationships between the hours in a manner that would likely not coincide with actual real-time system conditions over time. Instead, the Commission

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[1] *See* Order Approving Revised Interconnection Standard and Requiring Reports and Testimony, *Petition for Approval of Revisions to Generator Interconnection Standards*, No. E-100 Sub 101, at 58 (N.C.U.C. June 4, 2019).

[2] Amendments enacted pursuant to S.L. 2017-192 broadened the definition of "small power producer" to include QFs that use renewable resources as a fuel source, but not cogeneration facilities. 2016 Sub 148 Order at 18. While the Commission previously took care to acknowledge the distinction, *id.* at 37-38, the parties here have focused their arguments and testimony on solar QFs. Because issues specific to cogeneration facilities are not in dispute in this proceeding, the Commission will likewise dispense with the technicality of this amended definition and use the more general term QFs in this Order.

determines that the approach recommended by the Public Staff and Duke in the Rate Design Stipulation to provide a defined range of hours in distinct price groups based on periods where higher costs are generally expected will provide a reasonable and consistent price signal to QFs, encouraging them to align their generation with the time periods that have most value to customers in a forward-looking fashion.

Finally, the Commission agrees with Duke, NCSEA, and the Public Staff that real-time pricing rates for QFs could better align the Utilities' avoided cost rates to QF payments, but recognizes that such an option must be balanced with the Utilities' obligations under PURPA to provide a QF with the option to commit to deliver its power at the utility's avoided cost, either calculated at the time of delivery or calculated at the time the QF makes its legally enforceable commitment to deliver energy and capacity. 18 C.F.R. § 292.304(d)(2). Therefore, consistent with the recommendation of the Public Staff, the Commission directs Duke to evaluate and, if found to be appropriate, offer an RTP-based avoided cost tariff as an optional alternative to their Schedule PP in the next avoided cost proceeding.

Avoided Capacity Rates

In the 2018 Scheduling Order the Commission also directed Duke to address in its initial filings in this proceeding consideration of issues that impact DEC's and DEP's avoided capacity rates, such as the weighting of capacity value between the summer and non-summer seasons. States must consider a number of factors in determining avoided costs, including the availability of capacity or energy from a QF during the system daily and seasonal peak loads (including dispatchability, reliability, and the individual and aggregate value of energy and capacity from QFs), as well as the relationship of the availability of energy and capacity from the QF to the ability of the utility to avoid costs. 18 C.F.R. § 292.304(e). Pursuant to N.C.G.S. § 62-156, the Commission must consider the availability and reliability of QF power in establishing rates to be paid for capacity purchased from a small power producer.

The Rate Design Stipulation reflects that after Duke made its initial filings and engaged in discussions with the Public Staff, these two parties reached agreement on the appropriate seasonal and hourly allocations of capacity payments based on the Astrapé Capacity Value of Solar study that was filed with Duke's IRPs in Docket No. E-100, Sub 157. As with issues related to energy rate design, the Commission also finds that the Rate Design Stipulation is the product of give-and-take negotiations with respect to capacity rate issues, is material evidence in this proceeding, and is entitled to be given appropriate weight in this proceeding along with the other record evidence. The Commission gives substantial weight to the agreements articulated in the Rate Design Stipulation and the testimony in support thereof. For the following reasons the Commission concludes that these agreements should be approved as part of the acceptance of the Rate Design Stipulation.

First, the Commission finds that Duke's reliance on LOLE is appropriate in the context of determining when a QF can help a utility avoid or defer a planned capacity addition. Duke's evaluation of the PS-S2 scenario proposed by the Public Staff, as well as the sensitivity analysis performed by Duke in response to SACE's concerns over the relationship between winter load and cold temperatures, is adequately responsive to the concerns SACE raised. Second, the Commission finds Duke's description of the consideration of operating reserves that are held back in the SERVM model persuasive, as it demonstrates the reasonableness of Duke's modeling with respect to this issue. Third, the Commission agrees with Duke and the Public Staff that the use of the loss of load risk values to establish seasonal allocation factors is appropriate, as it aligns with cost causation principles. The Commission also agrees that these factors change over time, and that it is appropriate that the resource adequacy studies, along with all inputs and modeling assumptions, should be updated for use in the 2020 biennial IRP filings and taken into account in the 2020 avoided cost proceedings. Thus, as in the 2016 Sub 148 Order, the Commission will continue to review these issues in future avoided cost proceedings.

The Commission acknowledges that witness Johnson's assessment of historical loads for the years 2006 to 2017 has relevance to Duke's proposed seasonal allocation of future capacity need; however, the evidence in this proceeding confirms the Commission's determination in the 2016 Sub 148 Order that the high solar penetrations in Duke's service territory that it is experiencing today and expects to continue in the future will have different impacts on summer versus winter loads net of solar contribution than in the past. Therefore, the Commission agrees with Duke witness Snider that an assessment of historic loads without consideration of the impact of current and projected levels of solar output does not provide a complete or reasonably accurate picture of the appropriate seasonal allocation weightings to assign to forward-looking avoided cost rates.

The Commission disagrees with NCSEA witness Johnson that Duke's seasonal allocation is inconsistent with PURPA. Instead, the Commission finds that the seasonal allocation proposed by Duke and supported by the Public Staff provides a more reasonable quantification of the capacity costs that QFs enable the utilities to avoid. Consistent with N.C.G.S. § 62-156(b)(3), it is not only appropriate but required that the utility evaluate whether "the identified need can be met by the type of small power producer resource based upon its availability and reliability of power." Under the seasonal allocations proposed in the Rate Design Stipulation, a QF that can provide capacity during the identified need, as expressed by the LOLE hours, is fully compensated under seasonal capacity allocations that more accurately reflect the utility's avoided cost than seasonal allocations used in previous avoided cost proceedings. As indicated by Public Staff witness Thomas, to prevent overpayment to QFs for capacity that is not needed it is most appropriate to pay capacity payments only during hours where there is a loss of load risk, and therefore future capacity need, that can be avoided. The Commission agrees. Therefore, based upon the foregoing and the entire record herein, the Commission finds that DEC's proposed seasonal allocation weightings of 90% for winter and 10% for summer, and DEP's proposed seasonal allocation weighting of 100% for winter, are appropriate for use in weighting capacity value between winter and summer to calculate DEC's and DEP's avoided capacity rates in this proceeding.

On the related issue of the availability of winter DSM programs, the Commission agrees with Duke witness Snider that significant differences can exist between utilities, including climate, heating sources, industrial demand, and avoided costs, among others, as well as between portfolios of DSM programs targeting providing summer and winter capacity. Thus, the Commission finds Duke's assumptions regarding the availability of DSM programs for reducing winter peak demand are reasonable and appropriate for use in calculating avoided capacity rates in this proceeding. However, as discussed in the 2018 IRP proceeding, the Commission determines that Duke should place additional emphasis on defining and implementing cost-effective DSM programs that will be available to respond to winter demands. Therefore, the Commission will require Duke to address this issue in its initial statements filed in the 2020 biennial avoided cost proceeding.

Conclusion

In conclusion the Commission finds that the proposed avoided energy and avoided capacity rates presented in the Rate Design Stipulation are reasonable and appropriate. These stipulated rates are responsive to the Commission's direction to develop a rate design that sends stronger price signals to incent QFs to better match the generation needs of utilities. Therefore, the Commission concludes that the energy and capacity rates presented in the Rate Design Stipulation should be approved for use in calculating DEC's and DEP's avoided energy and capacity rates in this proceeding. As with other determinations in this case, these assumptions can be dynamic and can change in the future. The Commission will be receptive to revisiting these issues in future proceedings, as appropriate, to continue to evolve the State's implementation of PURPA, consistent with federal and state law, and to more accurately reflect utilities' avoided costs resulting from the purchase of QF power.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9 AND 10

The evidence supporting these findings of fact is found in the testimony of Public Staff witness Thomas and Duke witness Johnson. These findings are not contested.

Summary of the Evidence

Public Staff witness Thomas recommended that as a result of the changes to the rate design proposed in this proceeding, it would be appropriate for the Commission to make two minor changes to Commission Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6), which require applicants to submit a "detailed explanation of the anticipated kilowatt-hour outputs, on-peak and off-peak, for each month of the year." Witness Thomas suggested that the Rules be amended to instead request an hourly production profile from the applicant for one year. Witness Thomas indicated that this step would eliminate the additional processing required by the applicant to fit the output into the on- and off-peak periods and would also provide additional information regarding the facility's production profile for the Public Staff's review of the CPCN application. Tr. vol. 6, 395-97.

Duke witness Johnson testified that Duke agrees with the Public Staff that the stipulated rate design is inconsistent with the Rules' requirements and therefore appropriate for revision. He stated that Duke believes that other parties not currently participating in this proceeding may have an interest in the proposed rule revisions, and therefore the Commission should address the proposed revisions in a separate rulemaking proceeding. Witness Johnson further testified, however, that Duke requests that the Commission authorize a limited waiver of application of Rules R8-64 and R8-71 as they are currently written and approve the revisions proposed by witness Thomas on an interim basis until such time as a separate rulemaking proceeding can be initiated to review the proposed revisions. He stated that Duke discussed this proposal with the Public Staff and that the Public Staff did not have any objection to Duke's proposal. Tr. vol. 2, 282-85.

Discussion and Conclusions

In light of the changes to the energy and capacity rate designs being implemented in this proceeding, the Commission agrees with the Public Staff and Duke that the information currently required to be submitted in a CPCN application under Commission Rules R8 64(b)(6)(iii) and R8-71(k)(2)(iii)(6) requires an additional step to be taken by CPCN applicants beyond the presentation of an annual energy production profile, resulting in some additional administrative efforts that may only provide limited additional benefit, and that changes to the rule may be appropriate. The Commission also agrees that requiring a CPCN applicant to submit information regarding the additional factors influencing the shape of the production profile may be relevant in the Public Staff's and the Commission's consideration of the application. The Commission also agrees with Duke, however, that other parties not currently participating in this proceeding may have an interest in the proposed rule revisions and finds that establishing a separate rulemaking proceeding to evaluate the proposed rule revisions is appropriate. Therefore, the Commission will grant the limited waiver, as recommended by Duke and agreed to by the Public Staff, to allow CPCN applicants to substitute the following for the information currently required in Commission Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6):

> The projected annual hourly production profile for the first full year of operation of the renewable energy facility in kilowatt-hours, including an explanation of potential factors influencing the shape of the production profile, including fixed tilt or tracking panel arrays, inverter loading ratio, over-paneling, clipped energy, or inverter AC output power limits.

In the near future the Commission will issue an order establishing a rulemaking proceeding for the purpose of considering amendments to these Rules. The limited waiver allowed pursuant to this Order shall be in effect from the date of this Order until the Commission adopts revisions to Commission Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11 AND 12

The evidence supporting these findings of fact is found in Duke's verified JIS, DENC's verified Initial Statement, and the entire record herein.

Summary of the Evidence

In its JIS Duke states that DEC and DEP each calculated their respective avoided capacity cost based upon the overnight cost of a CT unit, using publicly available industry data from the Energy Information Administration (EIA), tailored to the extent needed to adapt such information to North Carolina and to conform to the Commission's previous avoided cost orders. Duke notes that the EIA CT capital cost is based on construction of a single CT unit at a greenfield site, and that consistent with prior Commission orders, the CT capital cost calculation does not assume any economies of scope. JIS at 15.

In its Initial Statement DENC indicates that it used the applicable costs of the Greensville combined cycle power plant as the basis for the CT equipment costs, which was consistent with the approach it took in the 2016 biennial avoided cost proceeding. DENC states that these costs are current and verifiable and represent the Company's actual procurement costs of CT equipment related to a power plant that is currently under construction and was expected to become operational in December 2018. DENC states further that for the remaining costs, including construction and owner costs, it utilized the PJM cost of new entry estimates, based primarily on the "PJM Cost of New Entry for Combustion Turbine and Combined Cycle Plants With June 1, 2022 Online Date" report prepared by The Brattle Group and Sargent & Lundy, dated April 19, 2018. DENC indicates that it also made several adjustments to the Brattle Study results, consistent with prior guidance from the Commission. DENC Initial Statement at 14-15.

In its Initial Comments the Public Staff indicates that it reviewed the capital cost inputs, line losses, and assumptions incorporated in the Utilities' avoided capacity calculations and finds them reasonable for purposes of this proceeding. Public Staff Initial Comments at 12, 17. The Public Staff recommends, however, that in future avoided cost proceedings the Utilities should evaluate and apply, if appropriate, cost increments and decrements to the publicly available cost estimates, including the use of brownfield sites, existing infrastructure, decrements for electrical and natural gas connections, and other balance of plant items, to the extent it is likely that this existing infrastructure is used to meet future capacity additions by the utility. The Public Staff notes that the Utilities have retired, and plan to retire over the next 10 years, significant natural gas and coal generation that may lead to the availability of several brownfield sites for potential future use for both baseload and peaking needs that may "represent potential value to customers that is not reflected in the costs of a greenfield site." *Id.* at 17-18, 66-70.

NCSEA's Initial Comments and the supporting affidavit of witness Thomas Beach advocate for an adjustment to the Utilities' respective CT costs to include an adder for firm natural gas pipeline transportation capacity cost or backup fuel (oil) arguing that CTs require either firm pipeline transportation capacity or backup fuel to ensure availability during winter peak hours when gas demand peaks and pipeline capacity is constrained. NCSEA Initial Comments at 23-24.

NCSEA further states in its Reply Comments that it opposes the Public Staff's suggestion that Duke incorporate brownfield site data in its CT cost calculations. NCSEA states that Duke predicts only two capacity additions which may be brownfield sites — neither of which is incorporated into its avoided cost peaker plant calculations — so Duke does not appear to intend to utilize numerous brownfield sites; therefore, the use of a greenfield site for good cost calculations is appropriate. NCSEA states, however, that it does not oppose Duke's utilization of brownfield sites in its next avoided cost filing, but only if Duke plans to utilize brownfield sites and it will be reflective of true cost data. NCSEA Reply Comments at 6-8.

In its Reply Comments DENC indicates that it has long advocated for the use of a brownfield CT to determine avoided capacity cost rates, and it agrees with the Public Staff's recommendation that brownfield sites may be efficient locations for construction of new CT facilities because of their land availability and existing gas and electrical infrastructure. DENC Reply Comments at 29-30.

Duke similarly indicates in its Reply Comments that it is not opposed to the Public Staff's recommendations to consider appropriate increments or decrements of publicly available CT cost data, such as consideration of a brownfield site. Duke states that the Public Staff's proposal reflects an incremental improvement over the current methodology that will more accurately reflect Duke's true avoided cost of capacity under the Peaker Methodology, as Duke's best estimate of a future avoidable CT is based upon the type and operating characteristics of the CT that DEC or DEP would actually build in the Carolinas. Duke emphasized that this may necessarily include confidential internal data and consultant's estimates that consider economies of scale adjustments as well as economies associated with brownfield sites in deriving future CT costs in the Carolinas. Duke Reply Comments at 32-34.

Duke also opposes NCSEA's recommendation that a hypothetical adder for firm natural gas pipeline transportation capacity cost be included in the Utilities' CT costs, noting that DEC and DEP do not reserve firm pipeline capacity for CTs. Duke Reply Comments at 35. Duke points to the Public Staff's Initial Comments that recognized DEC and DEP included the cost of fuel oil as backup, which allows Duke to exclude the cost of securing firm pipeline capacity for CTs. Public Staff Initial Comments at 7. Duke also highlights that this proposal would deviate from Duke's consistent application of the Peaker Methodology in North Carolina by assigning a cost premium solely to the winter capacity price period versus allocating DEC's and DEP's avoided capacity costs between the winter and summer periods based upon loss of load risk. Finally, Duke disputes NCSEA witness Beach's quantification of the additional pipeline capacity cost proposed to be added to the avoided winter capacity rate, finding that it was either miscalculated or excessive. Duke Reply Comments at 35 (citing Beach Affidavit at 18).

Discussion and Conclusions

In the Commission's Order Setting Avoided Cost Input Parameters, issued on December 31, 2014, in Docket No. E-100, Sub 140 (Sub 140 Phase One Order), the Commission determined:

> Because the focus of the peaker method is on a "hypothetical CT," for the next phase of this proceeding, the Commission concludes that the utilities should use installed cost of CT per kW from publicly available industry sources, such as the EIA or PJM's cost of new entry studies or comparable data. Data on the installed cost of CT per kW taken from publicly available industry sources are to be tailored only to the extent clearly needed to adapt any such information to the Carolinas and Virginia.

Sub 140 Pbase One Order at 48.

Based upon the foregoing evidence and the entire record in this proceeding, the Commission finds that the Utilities appropriately relied on publicly available industry sources for determining the installed per-kW cost of a CT and that their respective source information was tailored in a manner consistent with the guidance previously provided by the Commission. The Commission therefore finds that the CT cost information used by DEC, DEP, and DENC, respectively, is reasonable and appropriate for purposes of calculating avoided capacity costs in this proceeding.

The Commission further finds that the Public Staff's recommendation that in future proceedings the Utilities should evaluate and apply, if appropriate, cost increments and decrements to the publicly available cost estimates based on brownfield sites and existing infrastructure is appropriate in light of the number of current facilities that have been built on brownfield sites, as well as the number of plant retirements projected in the Utilities' IRPs. The Commission agrees that these existing facilities may represent potential value to customers, and that, to the extent the Utilities plan to utilize those existing facilities for new capacity additions, it is appropriate for the potential cost savings to be considered in avoided cost calculations. Therefore, the Commission will require the Utilities to evaluate these potential adjustments and address through their initial statements filed in the next avoided cost proceeding the extent to which each utility expects to use this existing infrastructure to meet future capacity additions by each utility and whether adjustments to their avoided capacity calculations are needed to account for this expectation.

In addition, the Commission agrees that there may be some circumstances where it is appropriate for the CT costs derived from generic publicly available estimates to be tailored based on internal data and actual construction experience. However, the Commission stresses that these adjustments must be clearly delineated and justified to ensure the Commission's effort in recent proceedings to increase the transparency in these CT cost inputs to the avoided capacity rate calculations is not lost. Further, when the Utilities use generic publicly available estimates, whether adjusted or not, the burden is on the utility to demonstrate that the estimates approximate the utility's actual costs, and procedures should be made available that allow not only parties but other interested persons to obtain access to the estimates and any adjustments made to the estimates, if applicable.

The Commission has carefully considered NCSEA's proposed upward adjustment to the Utilities' winter avoided capacity costs to account for hypothetical firm natural gas pipeline transportation capacity costs but is not persuaded that this proposal should be adopted. Comments filed by Duke and the Public Staff demonstrate that Duke does not purchase firm pipeline transportation capacity for CTs. The Commission agrees with these parties that it would be inappropriate to adjust the avoided capacity cost calculated under the Peaker Methodology by imposing an adder or decrement that does not reflect the utility's actual planned cost of building a CT in the Carolinas. Moreover, the Commission concludes that hypothetical firm natural gas transportation costs, as presented in this proceeding, are not sufficiently known and quantifiable to be included in avoided cost calculations approved herein. Based upon the foregoing and the entire record herein, the Commission finds that the exclusion of hypothetical firm pipeline transportation costs from the rates in this proceeding is appropriate. Accordingly, the Commission concludes that the Utilities' data on the installed cost of a CT used by the Utilities to calculate avoided capacity rates is appropriate for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13 – 15

The evidence supporting these findings of fact is found in Duke's verified JIS, DENC's verified Initial Statement, and the entire record herein.

Summary of the Testimony

In its Initial Statement DENC notes that in the 2016 Sub 148 Order the Commission directed the Utilities to address in the next avoided cost proceeding "the effect of distributed generation on power flows on each utility's distribution system and the extent of power backflows at substations." 2016 Sub 148 Order at 110. DENC indicates that consistent with the Commission's directive it updated the data related to power flows at its substations for the period September 2016 to August 2018 and found that transformers with high levels of connected distributed solar generation continue to experience backflow conditions where generation exceeds the load requirements of the circuit. DENC states that the number of transformers experiencing backflow has increased, indicating the continued appropriateness of not requiring DENC to include an adder for line losses in the calculation of avoided energy payments to QFs. DENC Initial Statement at 34-35.

In its JIS Duke states that it analyzed the levels of connected, under construction, and queued QF solar generating facilities interconnected to the DEC and DEP distribution systems to determine the number of substations that currently are experiencing or are expected to experience backfeed in the near future because of the recent growth in utility-scale solar QFs. As a result, DEP indicates that 50 out of 367 substations (14%) are currently backfeeding into the transmission system due to distribution-connected generation, and that based on the number of queued projects requesting to interconnect to the DEP distribution system in the near future, only about 96 out of 367 substations (26%) are estimated to experience backfeed. Duke indicates that this lower percentage as compared to DENC is in part due to the concentrated nature of QF solar development in more rural areas of the DEP eastern North Carolina service territory. Duke indicates that the percentages of DEC substations currently experiencing backfeed due to distribution-connected projects is significantly less — only 5%. As a result of its analysis, Duke indicates that it is appropriate for both DEC and DEP to retain a line loss adder for distribution-connected QFs eligible for Schedule PP at this time. Duke indicates, however, that for proposed distribution-connected QFs that are not eligible for the standard offer Schedule PP, Duke plans to consider on a case-by-case basis whether the QF's energy output would backfeed the substation and inject energy onto the transmission system, and whether retaining or eliminating the line loss adjustment from the avoided energy value is appropriate. JIS at 23-25.

In its Initial Comments the Public Staff indicates that it agrees with the information filed by the Utilities related to line loss adders and backfeeding of substations, as well as their proposals, and that the appropriateness of line loss adders should continue to be evaluated in future avoided cost proceedings. The Public Staff further recommends that in the next avoided cost proceeding the Commission require DEC and DEP to take into account the aggregate amount of renewable generation that will be, or is expected to be, interconnected by the end of the CPRE Program in their consideration of line loss impacts. Public Staff Initial Comments at 72-73.

SACE in its Initial Comments indicates that it retained Synapse to analyze DENC's most recent power flow data and came to the same conclusion that it reached in the 2016 Sub 148 Proceeding: solar QFs continue to provide line loss avoidance benefits, and it is inappropriate to entirely eliminate the line loss adder. SACE indicates that Synapse evaluated DENC's half-hour data associated with the 38 substations connected to QFs from August 16, 2017, to August 15, 2019, and found that the majority of substations are still experiencing positive flows during the majority of half-hour blocks. Synapse also evaluated the 38 substations during solar-producing hours and determined that line losses are still avoided during the majority of hours when QFs are generating power; therefore, DENC continues to benefit from solar QF line loss avoidance. SACE states that complete elimination of the 3% line loss adder may not accurately reflect line loss avoidance benefits, and it requests that the Commission require DENC to re-calculate and include a line loss adder in its avoided energy rates available to QFs. SACE Initial Comments at 18-20.

In its Reply Comments DENC disagrees with SACE's analysis for three reasons. First, SACE's analysis did not take into account irradiance levels to determine whether a solar QF could generate energy, and the period of time evaluated included the wettest year on record for much of DENC's territory. Second, SACE failed to acknowledge the general observable trend at several DENC substations that backflows are occurring with more frequency as more distributed solar generation is connected to the system. Third, even when DENC substations are experiencing positive flows, outside of a few outlier data points, the "room" remaining on the transformer before it starts experiencing backflows is reduced, and with the significant number of projects still seeking to interconnect, the prevalence of backflow conditions will continue to increase. DENC therefore recommends that the Commission reject SACE's analysis and find that it is appropriate for DENC to continue not to include the line loss adder in its avoided energy rates. DENC Reply Comments at 42-45.

Discussion and Conclusions

Pursuant to 18 C.F.R. § 292.304(e)(4), in determining avoided costs "the costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity," shall, to the extent practicable, be taken into account. In the 2016 Sub 148 Order the Commission concluded that line losses may not exist if power purchased from a distribution-connected QF is backfeeding to the substation, and the Commission directed the Utilities to further evaluate this issue in this proceeding.

Based on the foregoing and the entire record herein, the Commission finds that backflows are continuing to occur with regularity on a number of DENC's distribution system circuits and that backflows will continue to increase over time. The Commission further determines that this development greatly reduces or eliminates the benefits of the solar QFs' line loss avoidances, and that it is appropriate for DENC to continue to not include a 3% line loss adder from its standard offer avoided cost payments to distribution-connected QFs eligible for the standard offer.

The Commission also finds that it is appropriate for DEC and DEP to continue to incorporate the line loss factor in their standard offer avoided energy calculations at this time. With regard to Duke's proposal to assess the individual characteristics of the QF that is not eligible for Schedule PP standard offer rates and to address the line loss adder as part of the PPA negotiation process, the Commission agrees with Duke that such an analysis is consistent with N.C.G.S. § 62-156(c) by taking into consideration the individual characteristics of the QF. Lastly, the Commission finds it appropriate to require the Utilities to continue to study the impact of distributed generation on power flows on their distribution circuits and to provide the results of those studies as a part of their initial filings in the next biennial avoided cost proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16 – 18

The evidence supporting these findings of fact is found in Duke's verified JIS, DENC's verified Initial Statement, NCSEA witness Johnson's Affidavit, and the entire record herein.

Summary of the Evidence

In its JIS Duke proposes to continue to recognize a 1.05 PAF in its calculation of avoided capacity cost rates to be paid to QFs (other than certain hydroelectric QFs) eligible for the standard offer. In the 2016 Sub 148 Order, the Commission agreed with Duke that the equivalent forced outage rate (EFOR) metric represents an appropriate peak season reliability indicator, but to keep avoided cost aligned with other routine filings, the Commission directed the Utilities to support their recommendations for PAF calculations based on peak season equivalent availabilities for utility fleets in total in this proceeding. In response to this direction Duke compiled five years of historic equivalent availability (EA) data for the entire fleet during Duke's critical peak season months of January, February, July, and August — the critical peak season that reflects the high load periods in which Duke typically does not schedule planned maintenance outages for generating facilities. Duke further states that DEC's and DEP's respective EA during this timeframe averages 95%, which it argues continues to support a PAF of 1.05. JIS at 15-16.

In the 2016 Sub 148 Order the Commission also directed Duke to address whether the 2.0 PAF for hydroelectric QFs without storage should continue for the standard offer in this biennial proceeding. 2016 Sub 148 Order at 57. In its JIS Duke proposes in light of the Hydro Stipulation to retain the 2.0 PAF that the Commission had approved in previous avoided cost dockets. Under the terms of the Hydro Stipulation Duke agreed that it would continue to use a 2.0 PAF to calculate the avoided cost rates for hydroelectric QFs without storage and that have a capacity of 5 MW or less. Duke details that DEC and DEP negotiated the Hydro Stipulation in good faith, and its terms and conditions were based on both North Carolina's policy of supporting small hydroelectric QFs and the relatively small and finite amount of small hydroelectric capacity in the State. Thus, Duke supports continuation of the 2.0 PAF for hydroelectric facilities without storage in its standard offer Schedule PP (DEC) and Schedule PP-3 (DEP). JIS at 15-17.

In its Initial Comments the Public Staff generally agrees with the Utilities' base methodology for calculating the PAF, but notes that (i) as avoided cost proceedings continue to evolve, it may be appropriate for the Utilities to apply prospective, forward-looking EFOR components in the PAF calculation, and (ii) the Utilities' EFOR data should include a greater consideration of critical peak periods. The Public Staff states that because avoided costs are inherently forward-looking, it is also appropriate to take a forward-looking approach when determining each utility's EFOR for use in avoided cost calculations. The Public Staff argues that investments leading to improvements in the overall reliability (i.e., a decrease in forced outages) of the generation fleet should be given consideration. Therefore, although the Public Staff agrees that the Utilities met the intent of the 2016 Sub 148 Order with their filing of EFOR data, the Public Staff recommends that the Commission direct the Utilities to refile their fleet weighted average peak month EFOR using five years of historical data and a minimum of five years of prospective data (but in no event greater than ten years). The Public Staff further states that use of the EFOR data that includes greater consideration of critical peak demand periods on each utility's system is appropriate. Therefore, the Public Staff requests that the Commission direct the Utilities to perform a revised PAF calculation that includes June and December EFOR data.

In their Initial Comments the Public Staff and the NC Small Hydro Group support Duke's inclusion of the 2.0 PAF for hydroelectric QFs without storage that were eligible for the standard offer. Public Staff Comments at 72; NC Small Hydro Group Comments at 10. Emphasizing that there were only ten hydroelectric QFs between 1 MW and 5 MW in size, the NC Small Hydro Group in its Reply Comments also supports Duke's using a 2.0 PAF for hydroelectric QFs without storage up to 5 MW. The NC Small Hydro Group notes that a reduction of almost 50% in the PAF (from 2.0 to 1.05), coupled with the lower avoided cost rates in general proposed in this proceeding, would be financially devastating to those QFs. The NC Small Hydro Group also argues that the General Assembly recognized the need for hydroelectric QFs with a total capacity of 5 MW or less to have greater certainty in their future revenues by allowing those facilities between 1 MW and 5 MW to negotiate for contracts longer than five years. N.C.G.S. § 62-156(c)(ii). Thus, the NC Small Hydro Group claims that there is no reason to treat these facilities differently with respect to the 2.0 PAF. NC Small Hydro Group Reply Comments at 2-3.

In its Initial Comments NCSEA challenges Duke's proposed 1.05 PAF included in DEC's and DEP's avoided capacity rates, arguing that the historical EA data used to quantify the PAF narrowly defined January, February, July, and August as "peak season." NCSEA indicates that DEC and DEP have historically had summer peaks during the months between June and September, and, less frequently, winter peaks between December and March. Therefore, argues NCSEA, the historical data for both DEC and DEP do not support considering only January and February as winter peak months, while excluding December and March. Similarly, NCSEA argues that the historical data for DEC does not support considering only July and August as summer peak months, while excluding June and September. In his affidavit, NCSEA witness Johnson states that regardless of how carefully DEC and DEP schedule their maintenance activities away from summer and winter, extreme peaks can occur in response to extreme weather, overlapping the time periods when maintenance occurs. Therefore, NCSEA recommends that the Commission direct Duke to revise its avoided capacity rates to reflect a PAF between 1.08 and 1.10. NCSEA Initial Comments at 31-32; Johnson Affidavit at 36-37.

In its Reply Comments Duke acknowledges that it engaged in several discussions with the Public Staff concerning Duke's use of EA data, EFOR, and the appropriateness of the Public Staff's proposed adjustments to the PAF calculation. As a result of these discussions, Duke notes that it also supports the Public Staff's proposal to include the months of June and December if the EFOR metric is used to calculate the PAF. However, Duke does not think June and December represent appropriate months to use in determining the PAF and points to the fact that LOLE results used in the avoided cost rate design show that LOLE is zero in June and very small in December. Duke Reply Comments at 52.

Duke notes that the Commission directed Duke to use the EA as the metric to support the PAF. Further, Duke states that the Commission recognized that unit reliability should be evaluated during peak demand periods outside of planned maintenance intervals, and Duke believes that calculating the EA for the critical peak season months of January, February, July, and August is appropriate and complies with the 2016 Sub 148 Order. Duke Reply Comments at 51.

Duke also reports that it calculated the PAF based on the Public Staff's recommendation to use EFOR and to include the additional months of June and December and that the data would support a slightly lower PAF than the EA data using the months proposed by Duke. Accordingly, Duke supports either approach, as both approaches generally arrive at consistent results supporting a PAF of 1.05 or lower. Duke Reply Comments at 53-54. Duke also notes in its Reply Comments that it appreciates the Public Staff's recommendation to take a forward-looking approach and consider utility investments to improve reliability in quantifying the PAF. The data and process suggested by the Public Staff, however, is not conducted by Duke, and it would require Duke to make several assumptions that may not be readily accepted by the other parties. Duke believes that using five years of historic data captures periods when reliability issues may have surfaced for a unit and subsequent periods of improved reliability following investments and resolution. Thus, Duke maintains that the use of historic data largely provides the forward-looking process suggested by the Public Staff. Duke Reply Comments at 54-55. Finally, Duke agrees that the Public Staff's recommended EUOR metric may have merit because it accounts for unplanned outages classified as "maintenance" outages, which are outages that may be deferred beyond the end of the next weekend but must occur prior to the next planned outage. Thus, Duke recommends that the Commission approve a PAF of 1.05 for QFs except for hydro QFs without storage and agrees to continue discussions with the Public Staff to determine whether EUOR is a more appropriate reliability metric to use for the PAF in future avoided cost dockets. Duke Reply Comments at 56.

In its Reply Comments the Public Staff indicates that its Initial Comments did not recognize the complexity of comparing two separate metrics — EA and EFOR — and the challenges of applying a prospective element. Therefore, the Public Staff proposes that if a rate-based metric is applied, the use of three (as used by DENC) to five (as used by Duke) years of historic data is appropriate. Furthermore, an EFOR metric does not properly address other types of outages that can occur during the peak season. Thus, the Public Staff suggests that other reliability metrics used by the North American Electric Reliability Corporation (NERC), such as EUOR or weighted EUOR, may be an appropriate metric because it accounts for the types of outages that can occur during peak periods: forced outages, maintenance outages, and derates. The EUOR removes planned outages from the base calculation; therefore, planned outages, like a nuclear refueling outage (or equivalent) that could occur occasionally in the late fall or early spring, would not be included in the calculation and give a negative indication of utility performance during the critical peak seasons. As a result of this further analysis and discussion with the Utilities, the Public Staff recommends that the Commission approve the initial PAF calculations proposed by the Utilities in their November 1 filings for the purposes of this proceeding, but direct the Public Staff, Utilities, and other parties to discuss whether another metric may be a more appropriate reliability metric to support quantification of the PAF in future avoided cost proceedings. Public Staff Reply Comments at 15-17.

In its Reply Comments NCSEA states that Duke biased its current PAF calculations and that the calculations understate a QF's contribution to capacity during peak months. NCSEA renewed its recommendation that the Commission reject Duke's PAF proposal and adopt its proposal from its Initial Comments of a PAF between 1.08 and 1.10. NCSEA Reply Comments at 11-12.

In its Reply Comments SACE agrees with NCSEA and the Public Staff's recommendation that the Commission require the Utilities to perform a revised PAF calculation including the shoulder month data. SACE Reply Comments at 7-8.

On July 12, 2019, Duke filed a letter to counsel for the NC Small Hydro Group that outlines Duke's commitment to honor the Hydro Stipulation's provision for using 2.0 PAF for hydroelectric QFs without storage contracting to sell 5 MW and less until the expiration of the Hydro Stipulation on December 31, 2020. Duke details, however, that their commitment was subject to any adverse regulatory decisions by the Commission finding that Duke should not offer the 2.0 PAF to these small hydroelectric QFs. No party opposed Duke's proposal to retain the 2.0 PAF for hydroelectric QFs without storage eligible for Duke's standard offer tariffs in fulfillment of the Hydro Stipulation.

Discussion and Conclusions

In the 2016 Sub 148 Order the Commission recounted the historical approach to including a PAF in the Utilities avoided cost rates. 2016 Sub 148 Order at 55. The Commission has consistently recognized that because standard avoided capacity rates are paid on a per-kWh basis, setting avoided capacity rates at a level equal to a utility's avoided capacity cost absent a PAF effectively requires QFs to operate during 100% of the on-peak hours, without any reasonable opportunity to experience outages during each peak period, to receive the total available avoided capacity payment. Recognizing that the Utilities' generating units experience outages and do not operate 100% of the time, the Commission therefore has ordered the Utilities to apply a PAF, or a simple capacity multiplier, in calculating avoided capacity rates paid to QFs in previous avoided cost proceedings.

In the 2016 Sub 148 Order the Commission found that the methodology used to calculate the PAF should include greater precision than in past proceedings and required the Utilities to calculate the PAF using a system availability metric representing the reliability of the Utilities' respective systems during peak periods. In particular, the Commission agreed with Duke witness Snider that use of the EFOR metric represents the reliability of a unit or generating fleet during periods between planned maintenance intervals, making it an appropriate indicator of utility generating fleet performance during the utility's on-peak periods. The Commission additionally concluded that the similarly focused EA metric is also an appropriate peak season reliability indicator and ordered the Utilities to support development of the PAF using the EA metric in this proceeding to harmonize the development of the PAF with other routine filings (such as the power plant performance reports) made by the Utilities. 2016 Sub 148 Order at 57.

As in the 2016 Sub 148 Proceeding, the Commission determines that the evidence in this proceeding supports calculating the PAF based upon a metric or metrics that assess generating unit "availability" and that the methodology used to calculate generating unit availability should be based upon an informed discussion of utility system planning and load forecasting. The evidence in this proceeding also confirms that the purpose of the PAF, to allow QFs reasonable periods for unplanned outages similar to the utilities' fleet during the year, remains valid.

The parties do not dispute that DEC and DEP have generally complied with the 2016 Sub 148 Order to support development of the PAF using the EA metric. However, disagreement remains among the parties regarding the appropriate peak months to use to calculate the PAF when using either the EA or EFOR metric. Specific to Duke's initial reliance upon the EA of the generation fleet in total, as directed in the 2016 Sub 148 Order, the Commission finds that the LOLE results provide the correct signal for defining peak months when planned maintenance would not be scheduled for purposes of supporting the EA calculation. The Commission therefore determines that Duke appropriately included the months of January, February, July, and August in quantifying the PAF based upon EA, while the inclusion of additional months as recommends by NCSEA and initially by the Public Staff would introduce periods with planned outages that would have the effect of artificially increasing the EA and thereby overstating the PAF.

The Commission gives significant weight to the arguments of Duke and the Public Staff and the evidence in support thereof, which demonstrates that the PAF calculations proposed by the Utilities in their initial filings are consistent with the intent of the 2016 Sub 148 Order and appropriate for purposes of this proceeding. Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate to require DEC and DEP to use a PAF of 1.05 in their avoided cost calculations for all QFs except hydroelectric facilities without storage capability. The Commission also accepts the Public Staff's recommendation to consider other reliability metrics, specifically the EUOR, which may have merit given that EUOR includes an additional type of outage classified as "maintenance" outages which can also occur during peak demand periods. As detailed by the Public Staff and supported by Duke, the EUOR metric appropriately excludes planned outages from calculation of the PAF. The Commission therefore will direct Duke and the Public Staff to address the appropriateness of using EUOR as an alternative to EA through their initial filings in the next avoided cost proceeding.

Finally, although the Public Staff initially advocated that the Utilities should begin to incorporate prospective data in applying the PAF metric, the Public Staff's reply comments suggest that further discussions with Duke supports a conclusion that use of prospective data would be challenging and should not be approved at this time. It is uncontroverted that use of prospective data would be inconsistent with Duke's current process, and the Commission agrees that it may present additional complexities as it would require the Utilities to make assumptions that may not be readily accepted by other parties. The Commission therefore adopts the Public Staff's recommendation to require the Utilities to continue to use three (as used by DENC) to five (as used by Duke) years of historic outage rate data to support the PAF. In support of this finding, the Commission finds persuasive Duke's position that use of historic data largely provides a forward-looking process because it captures periods when reliability issues may have emerged for a particular unit and subsequent periods of improved reliability following investments and resolution of reliability issues. The Public Staff's own examples of historic capital investments that enhanced reliability stemming from prior Polar Vortex events also support the conclusion that investments in reliability are being recognized through the use of historic data.

In the 2016 Sub 148 Order, in addition to the 1.05 PAF included in avoided cost rate calculations that are generally available to QFs (through Duke's Schedule PPs), the Commission considered the 2.0 PAF included in the separate standard offer contract available to run-of-the-river hydroelectric QFs without storage capability (DEC Schedule PP-H; DEP Schedule PPH-1).

While the Commission concluded that changes to the calculation of the PAF were appropriate for the Schedule PPs, the Commission further concluded that the continued use of a 2.0 PAF in the calculation of rates for Schedules PP-H and PPH-1 should be approved. In reaching that conclusion, the Commission noted that historically the PAF was supported by state policy supporting the development and economic feasibility of small hydroelectric generating facilities, as provided in N.C.G.S. §§ 62-2(27a) and 62-156. The Commission also noted that no alternative PAF for run-of-the-river hydro QFs was proposed in that proceeding and concluded that considerations of regulatory certainty further supported allowing the Hydro Stipulation to continue through the two-year period that was covered by that biennial proceeding. Finally, the Commission directed the Utilities to address whether the utilization of a 2.0 PAF as provided in the Hydro Stipulation should continue as provided in that agreement.

The NC Small Hydro Group's uncontested evidence demonstrates that only a limited and finite amount of hydroelectric capacity exists in North Carolina. In addition, like in the previous avoided cost proceeding, there is no evidence here of an alternative PAF for run-of-the-river hydro QFs. Further, the Commission determines that prudential considerations and those of regulatory certainty apply with equal force here as was noted in the 2016 Sub 148 Order. Therefore, the Commission concludes that the Hydro Stipulation, including the 2.0 PAF, should be allowed to continue through its natural expiration on December 31, 2020.

The Commission has carefully considered the NC Small Hydro Group's arguments regarding state policy continuing to provide for favorable treatment of small hydro facilities. *See* N.C.G.S. § 62-156; House Bill 329, § 3 (establishing a designated avoidable capacity need to be met by purchases from certain legacy small hydroelectric QFs that had executed PPAs in effect as of July 27, 2017). As noted in the 2016 Sub 148 Order, the articulation of these policy goals, and the direction provided to achieve these goals, is not specific to the calculation of the appropriate PAF. Moreover, these provisions of the Public Utilities Act are specific to discrete questions that are a part of calculating avoided cost rates (the establishment of a designated avoidable capacity) and the maximum length of a negotiated contract. Now absent from the Public Utilities Act is the specific focus on the use of hydroelectric power previously included in the definition of "small power producers." N.C.G.S. § 62-3(27a). In light of these legislative changes, the Commission finds it appropriate to consider again the question of the appropriate PAF to apply in calculating capacity rates available to run-of-the-river hydro QFs after the natural expiration of the Hydro Stipulation. Therefore, the Commission will require Duke to address these issues through its initial statements filed in the next biennial avoided cost proceeding.[1]

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19 – 22

The evidence supporting these findings of fact is found in Duke's verified JIS and the entire record herein. The Commission takes judicial notice of all filings made in the 2018 IRP

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[1] DENC notes that it was not a party to the Hydro Stipulation and states that it does not appear to have any hydroelectric QFs in its service area. DENC Proposed Order at 93. The 2016 Sub 148 Order was less than clear on this point, and the Commission appreciates DENC's clarification of this issue in this proceeding. *See* 2016 Sub 148 Order at 7. There appears to be no possibility that a run-of-river hydroelectric QF will seek to avail itself of the opportunity to sell electric power from its facility to DENC; thus, the Commission does not require DENC to offer avoided cost rates that reflect a PAF of 2.0 for these QFs, nor does the Commission require DENC to address these issues in the next avoided cost proceeding.

Proceeding, Docket No. E-100, Sub 157, as they relate to the Utilities' respective determination of projected capacity needed to serve system load.

Summary of the Evidence

In its JIS Duke notes that in the 2016 Sub 148 Order the Commission accepted the reasonableness of the overall Peaker Method and found that avoided capacity value should be recognized beginning with the year that the utility's IRP forecast shows a capacity need. Duke states that this determination was consistent with N.C.G.S. § 62-156(b)(3), as amended by House Bill 589, which provides that a "future capacity need shall only be avoided in a year where the utility's most recent biennial integrated resource plan . . . has identified a projected capacity need to serve system load and the identified need can be met by the type of small power producer resource based upon its availability and reliability of power . . . ." JIS at 12-13.

Duke indicates that its avoided capacity rates are consistent with the 2016 Sub 148 Order and N.C.G.S. § 62-156(b)(3) in that they recognize each utility's next avoidable future capacity need based upon DEC's and DEP's most recent biennial IRPs filed on September 5, 2018, in Docket No. E-100, Sub 157 (2018 IRPs). These 2018 IRPs show that DEC's next avoidable capacity need is a planned 460 MW (winter rating) CT in 2028, while DEP's next avoidable capacity need is a planned 30 MW short-term market capacity purchase in 2020. *Id.*

In its Initial Comments the Public Staff does not take issue with DEC's and DEP's identified first avoidable capacity needs, as presented in their 2018 IRPs. The Public Staff notes that pursuant to the 2018 IRPs, QFs located in DEC's service area that select a ten-year contract would receive avoided capacity rates that reflect the present value of one year of avoided capacity costs in 2028; whereas, QFs located in DEP's service area will receive avoided capacity rates that reflect the present value of avoided capacity costs for nine of the next ten years. The Public Staff also does not take issue with DENC's identification of its deferrable capacity need in 2022, as shown in its 2018 IRP filed May 1, 2018, in Docket No. E-100, Sub 157. The Public Staff also indicates that if utility inputs change, such as the anticipated date of the first avoidable capacity need, the utility should update its avoided capacity calculations for negotiated contracts, as well as for use in CPRE Tranche 2. Public Staff Initial Comments at 9-10, 17.

In its Initial Comments SACE notes that DEP's IRP showed a series of nuclear uprates between 2019 and 2028, but DEP did not indicate whether the uprates would involve capital investments or only a change in the enrichment of the fuel source. SACE states that if capital investments are required in the near term, there could be an avoidable capacity need as early as 2019, and that such capacity should be reflected in DEP's avoided capacity rates. SACE Initial Comments at 14.

In regard to DEC's capacity need, NCSEA notes in its Initial Comments that while DEC contends that it has no capacity need until 2028, its IRP shows a 30-MW short-term market capacity purchase in 2020 and uprates at existing units in 2021 through 2025. NCSEA contends that these market purchases and uprates are relevant in determining an avoidable capacity need and that Duke has not addressed whether the capacity expansions can be met by small power producers. NCSEA Initial Comments at 11.

In response to NCSEA's and SACE's comments on DEC's and DEP's first avoidable capacity needs, Duke explains in its Reply Comments that DEC and DEP determine their future (avoidable) generation needs based on the difference between customer demand, net of energy efficiency, and the sum of the utility's existing resources and projected resources, to meet a required annual planning reserve margin (currently 17%). When the annual planning reserve margin falls below 17%, new capacity is required. As indicated by DEC's and DEP's 2018 IRPs, DEC's and DEP's first avoidable capacity needs are in 2028 and 2020, respectively. Duke comments that while future planned market power purchases are undesignated resources and thus avoidable, near-term designated capacity additions, including nuclear uprates, do not constitute avoidable capacity. Duke indicates that the near-term planned nuclear uprates during 2019-2022 are O&M-related investments rather than new, undesignated capacity additions. According to Duke, DEC and DEP uprate their nuclear plants as part of the normal course of business during maintenance cycles. These planned uprates include normal maintenance of system equipment, such as feedwater heaters and moisture separator reheater tubes. Duke concludes that as these activities will occur regardless of whether QF capacity or energy is available, the capacity gained through uprates cannot be avoided. Duke also indicates that the uprates are relatively small and would have very little impact on the timing of the next undesignated capacity resource need. Duke Reply Comments at 37-40.

Duke agrees with the Public Staff's recommendation that DEC and DEP should update their first year of avoidable capacity need in calculating avoided cost rates for future negotiated contracts as well as for CPRE Tranche 2. Thus, if DEC's or DEP's first avoidable capacity needs change due to new contracts for purchased capacity, they would update their avoided capacity cost calculations for negotiated contracts with larger QFs. Duke Reply Comments at 41-42.

In its Reply Comments the Public Staff restates that the year of capacity need should be determined by the IRP. It agrees with Duke that plant uprates should not constitute a deferrable capacity need as they are essentially "sunk costs." The Public Staff points out that a utility should make plant uprates when it is reasonable and prudent to do so, such as to meet revised regulatory requirements, address aging and obsolete parts, increase operational flexibility to meet changing grid constraints, install new equipment that is more efficient or reduces parasitic loads, and better utilize the existing equipment and total stored energy of a nuclear fuel assembly.

The Public Staff finds valid intervenors concerns related to the lack of a specific statement of capacity need in each utility's 2018 IRP. The Public Staff notes that its initial comments in Docket No. E-100, Sub 157 recommended that a Utility Statement of Need be filed in the IRP docket in order to remove uncertainty surrounding the exact year of avoidable capacity need and to provide a clearer standard for all parties in various regulatory proceedings.

In its Reply Comments SACE indicates that it does not object to the Public Staff's recommendation that avoided capacity costs should be updated for negotiated contracts between biennial avoided cost proceedings to accurately reflect utility capacity needs, but SACE recommends that any such adjustments resulting from capacity additions of utility-acquired resources must have been included in the utility's most recently approved IRP. SACE agrees with NCSEA that DEC's projected 30-MW short-term market capacity purchase in 2020 should be considered an avoidable capacity need. SACE makes reference to its comments in Docket

No. E-100, Sub 157 in which SACE contended that Duke failed to evaluate the potential retirement of aging fossil plants in its modeling and recommended that the Commission direct Duke to revise its IRPs by allowing its modeling to evaluate the cost-effectiveness of retiring fossil plants in the near term. In its Reply Comments in this proceeding, SACE recommends that if the Commission adopts this IRP recommendation, Duke should revise its avoidable capacity needs to include any capacity needs identified as a result of this modeling. SACE Reply Comments at 7.

Regarding DENC, SACE contends that DENC has not complied with the 2016 Sub 148 Order directive to provide avoided capacity payments in years that the utility's IRP forecast period demonstrates a capacity need. SACE argues that because the VSCC rejected the Company's IRP as originally filed in 2018, the 2018 IRP does not accurately represent the Company's future capacity plans and cannot be relied upon in this proceeding. SACE also contends that DENC has not identified a "preferred plan" in its 2018 IRP, and that without a preferred plan the capacity need should be demonstrated based on the Alternative Plan that anticipates the most immediate capacity need. Finally, SACE contends that certain capacity additions in 2019, 2020, and 2021 that are reflected in the 2018 IRP could be deferred, delayed, or reduced "as a result of QF capacity contributions," and therefore that DENC's calculation of avoided capacity costs without such costs through 2021 does not comply with the FERC's conclusion in Order No. 69 that QFs should be compensated for avoided capacity if purchasing from that QF allows the utility to avoid construction, to build a smaller unit, or to purchase less firm power.

In its Reply Comments the NC Small Hydro Group agrees with the Public Staff that the Commission should require a Utility Statement of Need in the IRP process. However, the NC Small Hydro Group recommends that this Statement of Need process be completed before the 2019 IRP update in order to benefit the current biennial avoided cost docket. NC Small Hydro Group Reply Comments at 5.

In response to SACE, DENC notes that it refiled its 2018 IRP on March 7, 2019, as required by the VSCC. DENC points out that the Company's need for capacity did not change in the refiled 2018 IRP using the input assumptions required by the VSCC, including the solar build-out per the Virginia GTSA in Plan F (No CO_2 Tax with GT Plan). Thus, the revised capacity expansion plan continues to show the first capacity need in the "No CO_2" case to occur in 2022. DENC Reply Comments at 32-33.

DENC also argues that it based its determination of capacity need used in calculating avoided capacity rates on the "No CO_2 case resource expansion plan" in its originally filed 2018 IRP. Using the projection of the next capacity need in Plan F in the refiled 2018 IRP, the basis for the Company's determination of capacity need for purposes of calculating avoided capacity rates did not change. DENC states that its reliance on a "No CO_2" plan is appropriate because it is consistent with the Commission's conclusions in its Sub 140 Phase One Order that only known and quantifiable costs should be reflected in avoided cost calculations. DENC states that as CO_2 costs are not yet known or quantifiable, a preferred plan is not relevant to the determination of avoided cost, and the Company's reliance on a "No CO_2" plan is appropriate. *Id.* at 33-34.

Finally, DENC responds to SACE's contention that certain capacity additions in 2019, 2020, and 2021 reflected in the 2018 IRP could be deferred, delayed, or reduced by QF capacity, and thus DENC's calculation of avoided capacity costs without such costs through 2021 was inconsistent with the FERC's directive that QFs should be compensated for avoided capacity if purchasing from that QF allows the utility to avoid construction, build a smaller unit, or purchase less firm power. DENC states that new QFs signing PPAs during the biennial period will not avoid any capital costs related to these near-term generation projects; indeed, some of the projects projected for 2019 to 2021 in the IRP are already under construction. *Id.* at 34.

Discussion and Conclusions

The Commission concludes that DEC, DEP, and DENC have complied with N.C.G.S. § 62-156(b)(3). In its August 27, 2019 Order on the 2018 IRPs in Docket No. E-100, Sub 157, the Commission found the IRPs of DEC, DEP, and DENC to be reasonable for planning purposes. In this proceeding, the Commission finds that the Utilities have also appropriately identified their first avoidable capacity needs, as presented in their 2018 IRPs. The Commission agrees with the Public Staff that if utility inputs change, the utility should update its avoided capacity cost calculations for negotiated contracts, as well as for use in CPRE Tranche 2. As pointed out by NCSEA, planned wholesale power purchases are undesignated resources and thus avoidable. However, with respect to the uprates at issue in this proceeding, the Commission determines that there is insufficient evidence in this record for the Commission to find that these plant uprates shown in DEC's or DEP's most recent IRPs are deferrable or avoidable for purposes of establishing a capacity rate; therefore, these uprates shall not be included in the determination of avoided capacity costs for purposes of this proceeding. Beginning with the 2020 IRP, the Commission finds that it is appropriate for the Utilities to include a specific statement of undesignated capacity need that is avoidable by QFs in order to remove uncertainty surrounding the exact year of capacity need and to provide a clearer standard for all parties in various regulatory proceedings, especially the next biennial avoided cost proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 23 AND 24

The evidence supporting these findings of fact is found in testimony of Duke witness Snider, DENC witness Petrie, Public Staff witness Hinton, and NCSEA witness Johnson. The Commission takes judicial notice of all filings made in the 2018 IRP Proceeding, Docket No. E-100, Sub 157, as they relate to the Utilities' assumptions regarding expiring wholesale purchases from QFs, and also takes judicial notice of House Bill 329, as recently enacted into law on July 19, 2019.

Summary of the Evidence

In its Initial Comments NCSEA states that it understands DEC's and DEP's IRPs to assume that a QF will continue providing capacity in DEC's and DEP's respective generation stacks even after the expiration of the QF's PPA. NCSEA argues that renewals of current PPAs that include payment for capacity should continue to include capacity payments, as otherwise Duke would be forced to obtain capacity from another source. NCSEA's witness Johnson also addressed this issue and recommends that avoided costs be analyzed in this proceeding using the assumption that existing QF contracts could be displaced by new QF PPAs. Witness Johnson believes that it is not reasonable to assume either that none of smaller, existing QFs are providing Duke with capacity or that all of these existing QFs will renew their contracts and provide capacity without compensation. NCSEA therefore recommends that the Commission consider the rights of QFs with expiring PPAs and that seek to renew and provide these QFs with some certainty in this proceeding. NCSEA Initial Comments at 10-11.

The NC Small Hydro Group notes that existing biomass and hydroelectric capacity resources subject to contract renewals decrease over time in DEC's IRP from 119 MW in 2019 to 52 MW in 2033, and in DEP's IRP from 266 MW in 2019 to 0 MW in 2033. The NC Small Hydro Group contends that Duke's approach leads to reductions in capacity payments for QFs and rates lower than actual avoided capacity costs. It argues that Duke's approach penalizes these QFs that have provided energy and capacity for years and suggests that it is inconsistent with PURPA. It distinguishes its situation where existing QF capacity would be displaced from that in the case of *City of Ketchikan, Alaska*, 94 FERC ¶ 61,293 (2001), where the utility was not required to pay for capacity that would displace the utility's existing capacity. The NC Small Hydro Group contends that House Bill 589 only addressed future capacity and did not require the Utilities to disregard existing QF capacity or stop capacity payments to this existing capacity after the existing contract expires based upon an assumption that the QF will renew its contract to deliver power for a future term. NC Small Hydro Group Initial Comments at 5-10.

In its Reply Comments Duke states that DEC's and DEP's 2018 IRPs do not assume that QFs will continue providing capacity after the QF's PPA term ends, but rather reduce the exiting capacity by the amount of capacity provided by the expiring wholesale purchase contract in the year following the contract expiration. Duke notes that it has been consistently using this approach for DEC and DEP in all IRPs since 2012. Duke explains that using this approach, the expiration of a wholesale contract can affect the timing of its first capacity need. Duke contends that 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. Duke recognizes parties' interest in the timing of capacity additions and deficits and agrees to address this issue in future IRPs through a new Statement of Need section, as recommended by the Public Staff. Duke Reply Comments at 42-47.

In its Reply Comments NCSEA states that it finds compelling the NC Small Hydro Group's legal argument that existing QF capacity should have an expectation of a renewal of the capacity in the QF's new PPA. NCSEA supports recognizing the capacity need as relating back to the date of the original contract for a QF as proposed by the NC Small Hydro Group. NCSEA Reply Comments at 10-11. SACE in its Reply Comments also agreed with the NC Small Hydro Group's position. SACE Reply Comments at 6.

The NC Small Hydro Group in its Reply Comments agrees with NCSEA's position that existing QFs already in the utility's generation stack should continue to be paid for capacity after PPA renewal. The NC Small Hydro Group points out that if QF capacity is undervalued, existing QFs may not be able to renew their PPAs due to economic reasons, resulting in less QF generation and the need for more capacity from natural gas or other non-renewable resources. The NC Small Hydro Group also reiterates its position supporting the Statement of Need proposed by the Public Staff. NC Small Hydro Group Reply Comments at 4.

In its Reply Comments the Public Staff agrees with the NC Small Hydro Group's assertion that DEC's and DEP's 2018 IRPs show the existing capacity of biomass and hydroelectric Non-Utility Generators (NUGs) declining over time, indicating that DEC and DEP do not assume these contracts will be renewed or replaced in kind. However, the Public Staff does not agree with the NC Small Hydro Group's conclusion that this approach will "reduce capacity payments to QFs." The Public Staff points out that by assuming that small hydro and biomass capacity will expire at the end of the current PPA term, each utility's available capacity is effectively decreased, increasing the need for undesignated future resources. Public Staff Reply Comments at 26-28; *see also* NC Small Hydro Group Initial Comments at 7.

The Public Staff also notes that DEC's and DEP's IRPs appear to assume that solar QF contracts will be renewed or replaced in kind, unlike the treatment applied to hydro and biomass PPAs. The Public Staff points out that this disparity in the treatment of solar and other QF resources could impact avoided capacity rates in future proceedings, though not in the current proceeding. As this issue will become more and more important in future years, the Public Staff notes the importance of having the utilities file a formal Statement of Need as recommended by the Public Staff in the Sub 157 proceeding. Public Staff Reply Comments at 26-28.

In his direct testimony Duke witness Snider stated that Duke has appropriately assumed in its IRPs that upon expiration of any third-party wholesale purchase contract, capacity is reduced by the amount of the capacity provided by the expiring wholesale purchase contract in the year following contract expiration. Witness Snider reiterated that this is Duke's long-standing approach used in its IRPs. He maintained that it is prudent for the Companies not to rely on future third-party owned capacity in years unless there is a contract or other legally enforceable commitment. Witness Snider also pointed out that QF owners have the right at the end of a contract to make their unrestricted decision as whether to renew their PPAs, cease business, or sell their energy and capacity to another buyer. Further, there is no guarantee for Duke and its customers that the QF will be able to provide energy and capacity after expiration of the PPA. Tr. vol. 2, 52-55.

Public Staff witness Hinton reviewed Duke's assumptions regarding expiring PPAs. He testified that Duke's IRPs indicate a reduction in capacity from expiring biomass and hydro PPAs in the planning period, but an increase in capacity from solar facilities. Witness Hinton stated that while this assumption regarding solar PPAs may be appropriate for planning purposes, it is inappropriate for determining the first year of capacity need as it could elongate the time before there is a capacity need. Witness Hinton noted that the Statement of Need addition to the Utilities' future IRPs, as proposed by the Public Staff in its IRP comments, would help clarify the assumptions used by the Utilities. Witness Hinton also indicated that after further discussions with Duke, it was his understanding that Duke used the same assumptions for all wholesale contracts — i.e., that the contracts would expire and the capacity would no longer be available — in establishing its first year of capacity need for avoided cost purposes. Further, regardless of the assumption made regarding expiring QF solar contracts being replaced in kind in the future, the first year of capacity need would be the same for DEC and DEP in their 2018 IRPs and this proceeding. Finally, witness Hinton indicated that he disagreed with the position of the NC Small Hydro Group and NCSEA that the Utilities should assume that all QF contracts renew and that existing QFs should be entitled to a capacity payment beginning in the first years of their new contract term. Tr. vol. 6, 311-14.

NCSEA witness Johnson argued that existing capacity is used in the IRP process to determine whether there is a need for additional capacity, and this existing capacity included wholesale contracts. He contended that contract renewals do not add new capacity but maintain existing capacity. Witness Johnson stated that because of long lead times for new generating units, the first year of a capacity need is likely always to be at least a few years away. He found Duke's approach to be discriminatory as QFs may never receive capacity payments and Duke would continue to receive full capacity cost recovery for its units. He warned the Commission against interpreting House Bill 589 to require taking the capacity of QFs without compensating them fairly as unfair and discouraging investment in North Carolina. Witness Johnson recommended that QFs be given the option to sign contracts several years before the existing contract ends so that there is a legally binding commitment that could be included in the existing generation in a utility's IRP. Tr. vol. 6, 206-15.

In his rebuttal testimony, witness Snider indicated that the Commission's decision on this issue must be considered in accordance with House Bill 589's amendment of N.C.G.S. § 62-156(b)(3), which provides 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 and the identified need can be met by the type of QF resource based upon its availability and reliability of power, other than swine or poultry waste for which a need is established consistent with G.S. 62-133.8(e) and (f)." He also pointed to the Commission's holding in the 2016 Sub 148 Order that the purpose of PURPA was not to force utilities and their customers to pay for unneeded capacity. Witness Snider noted that purchases of generation from swine and poultry waste were exempted as the General Assembly in House Bill 589 designated an immediate need for this generation to meet the requirements of the REPS Program. Tr. vol. 2, 97-102.

Witness Snider also pointed out that Public Staff witness Hinton had indicated in his testimony that the Public Staff supported Duke's assumptions as to expiring contracts. In response to NCSEA witness Johnson's claim that Duke's approach to contract renewals is discriminatory, witness Snider contended that, actually, witness Johnson's approach was discriminatory in that it would favor existing QFs over new capacity resources, including new QFs. Witness Snider explained that House Bill 589 directs the Commission to treat all small power producer QFs in a like manner, whether existing or new. In response to witness Johnson's contention that Duke's approach would result in a QF never being paid for capacity, witness Snider pointed to the DEP 2018 IRP's avoidable need in year 2 and the utilities' requests for proposals for new resources. Witness Snider also rebutted witness Johnson's contentions that it would be discriminatory not to continue paying for QF capacity, whether needed or not, after contract expiration, as utilities receive full capacity cost recovery in rate base. He pointed to the Commission's conclusions in 2016 Sub 148 Order where the Commission differentiated QFs from utilities, especially as utilities have an obligation to serve customers. Tr. vol. 2, 102-09.

Discussion and Conclusions

The Commission finds House Bill 589's and House Bill 329's recent amendments to N.C.G.S. § 62-156(b)(3) to be controlling on this issue. House Bill 589 provides 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 and the identified need can be met by the type of QF resource based upon its availability and reliability of power . . .," but expressly carves swine and poultry waste generation out from this requirement based upon their designated need to meet REPS compliance. Section 3(a) of House Bill 589 adds to N.C.G.S. § 62-156(b)(3) an additional carve out for "legacy" hydroelectric QFs of 5 MW or less selling and delivering power under QF PPAs in effect as of July 27, 2017. Notably, Section 3(b) of House Bill 329 provides further direction to the Commission:

> The *exception for hydropower* small power producers *from limitations on capacity payments established in G.S. 62-156(b)(3),* as amended by Section 3(a) of this act, shall not be construed in any manner to affect the applicability of G.S. 62-156(b)(3) as it relates to any other small power producer. [Emphasis added.]

The Commission finds that the clear intent of the General Assembly as shown through House Bill 589 and House Bill 329 is to treat swine and poultry waste QF resources and legacy small hydro QF resources differently from other QFs in regard to valuing their ability to avoid the Utilities' projected capacity needs to serve system load during the future IRP planning period. Subsection (b)(3) of N.C.G.S. 62-156, as amended by House Bill 589, specifically identifies the Utilities' statutorily designated need to procure swine and poultry waste resources to meet REPS, while House Bill 329's specification that the small hydroelectric QF's PPA be in effect as of July 27, 2017 (the date that House Bill 589 was enacted into law), establishes that these legacy small hydroelectric QFs are similarly now meeting a statutorily designated, resource-specific capacity need that cannot be met by other types of QF resources. Establishing avoided cost rates based upon the ability of specific QF resources to meet statutorily designated requirements to procure capacity from specific QF resource types has been recognized to be consistent with PURPA. *Cal. Pub. Utility Comm'n.*, 133 FERC ¶ 61,059 at 20, 26-30 (2010) (providing that in setting avoided cost rates, a state "may take into account obligations imposed by the state that, for example, utilities purchase energy from particular sources of energy or for a long duration"), *reh'g denied*, 134 FERC ¶ 61,044 (2011). For other types of QF generation, which do not meet a designated capacity need specified by the General Assembly, it is appropriate for QFs electing to obligate themselves to deliver power for a new contract term to be considered as avoiding undesignated new generation projected to be needed in the future to serve the utility's system load; therefore, N.C.G.S. § 62-156(b)(3) prescribes that a QF avoiding an undesignated future capacity need shall not be entitled to a capacity payment unless the utility's IRP identifies an undesignated capacity need to meet the utility's system load that the QF may avoid within the contract period. The Commission also agrees with Duke and the Public Staff that QFs commit to deliver their power for a specified term and that it would be imprudent resource planning to assume that QFs are obligating themselves to deliver capacity and energy past the end of their contract term. Moreover, it would be discriminatory between QFs to assume that a pre-existing QF has a priority right to enter into a new contract to sell and deliver capacity over a new term versus the rights of any other QF to commit itself to avoid the utility's capacity need.

Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate for the Utilities to recognize any new commitment by a swine or poultry waste QF generator or a legacy small hydroelectric facility 5 MW or less in capacity that has a power purchase agreement in effect as of July 27, 2017, obligating itself to sell and deliver its full energy and capacity output over a future contract term as helping the Utilities avoid a designated future capacity need beginning in the first year of the new QF PPA, pursuant to the N.C.G.S. § 62-156(b)(3), as amended by House Bill 329. For other types of QF generation, it is appropriate under PURPA and consistent with N.C.G.S. § 62-156(b)(3), for the Utilities to recognize a QF's commitment to sell and deliver energy and capacity over a specified future fixed term as avoiding an undesignated future capacity need beginning only in the first year when there is an undesignated (i.e., avoidable) capacity need identified in DEC's, DEP's, or DENC's most recent IRPs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 25 – 26

The evidence supporting these findings of fact is contained in the testimony of Duke witnesses Snider and Johnson, DENC witness Petrie, NCSEA witness Johnson, and Public Staff witness Hinton.

Summary of the Evidence

In its Initial Comments NCSEA states that because of "well documented delays" in the interconnection queue, a Sub 158 PPA will likely not begin providing capacity until December 2021 or later. When considering when there is a capacity need, consistent with the utilities' 2018 IRPs, NCSEA argues it would be more appropriate to use December 31, 2021 as the presumptive in-service date for the purpose of calculating avoided capacity costs. NCSEA Initial Comments at 12. In his affidavit, NCSEA witness Johnson states that the utilities treat 2019 as the starting point for calculating the biennial standard offer avoided cost rate calculations. Johnson Affidavit at 58-59. Witness Johnson further states the current in-service date is an "arbitrary, and obviously unrealistic, assumption" and December 31, 2021, or three years later, is a more reasonable assumption. *Id.*

NCSEA Witness Johnson further asserts in his affidavit that an unrealistic timeline distorts all of the avoided cost calculations but has the most impact on the avoided capacity rates. He states, for example, "DENC assumes the QF will start delivering power in January 2019, and it does not pay for capacity during the years 2019, 2020 and 2021. This effectively reduces its capacity rate by about 30% for a 10-year fixed rate contract." *Id.* at 59-60. Witness Johnson states that DEP and DEC would have similar under-payments for capacity depending on their capacity need in certain years over the span of a ten-year contract. In its Reply Comments SACE agrees with NCSEA's recommendation and states that it considers using a December 31, 2021, as the date on which Sub 158 contracts are considered to begin providing capacity to be a reasonable approach. SACE Reply Comments at 6.

In its Reply Comments Duke states that its proposed avoided capacity rate calculations are based on DEC's first avoidable capacity need in 2028 and DEP's first avoidable capacity need in 2020, as addressed in their respective 2018 IRPs. Duke Reply Comments at 41. Dukes' Schedule PP rates are based upon an assumed 2019 in-service date and are available for an approximate two-year period. Duke states that NCSEA's premise that smaller QFs eligible for the standard offer will not enter into service for years is factually incorrect because small QFs 1 MW or less proceeding under Section 3 Fast Track and Supplemental Review interconnection processes routinely complete construction and are placed in service in less than a year. *Id.* at 49. In addition, Duke asserts that the statutory process for fixing standard offer avoided cost rates does not precisely align with the utility's avoided cost as being incurred the moment a generator comes online, and argues that the QF has the ability to delay the point at which it establishes its LEO or it can elect to pursue a negotiated PPA. Duke therefore states that the Commission should reject NCSEA's proposed delayed hypothetical in-service date. *Id.* at 49-50.

In its Reply Comments DENC argues that setting the January 2019 start date for entering into a standard PPA is an administratively efficient way to develop standard rates and terms for small QFs, rather than adjusting assumed start dates based on uncertainty regarding QFs' commercial operation dates. DENC Reply Comments at 31.

In its Reply Comments the Public Staff states that the Utilities' current approach for establishing the presumed in-service date for standard offer QFs is reasonable and is an equitable way of treating existing and new facilities. The Public Staff, however, recommends that the Commission direct the Utilities to clarify the point when an existing QF seeking to renew its PPA can establish a new LEO for both calculating rates and determining when the facility will be eligible to receive a capacity payment. The Public Staff states that "[t]his period of time should be long enough to allow the QF to have sufficient information regarding its proposed rates to determine whether it would seek to renew, as well as provide the utility with assurance as to whether it may rely on the QF in its planning for future capacity needs." Public Staff Reply Comments at 29.

In response to witness Hinton's recommendation regarding existing QFs that seek to establish a new commitment, Duke witness Johnson states that Duke does not accept requests to enter into a new PPA earlier than 12 months prior to the end of the QF's existing PPA term. For negotiated contracts, consistent with the standard prescribed by the Commission in the Notice of Commitment form, the QF must execute the newly tendered PPA within six months. Tr. vol. 2, 281. An existing QF eligible for the standard offer would automatically have the right to enter into a new ten-year term PPA at Duke's standard offer avoided cost rates applicable to new QFs as of the date the QF's current PPA is set to expire.

Regarding negotiated contracts, NCSEA and witness Johnson also state that the Utilities should be directed to calculate rates for negotiated PPAs based on the presumed in-service date of the QF subject to the negotiated PPA. NCSEA Initial Comments at 12; Johnson Affidavit at 59. The Public Staff agrees that it is appropriate for the utility and QF negotiating a PPA to agree to a presumed in-service date for rate calculation purposes that takes into account any anticipated delays in the project coming online, such as delays in the interconnection queue. Public Staff Reply Comments at 29-30.

In direct testimony Duke witness Snider stated that small QFs can proceed under Section 3 Fast Track and Supplemental Review interconnection under the NCIP, and they are routinely placed in service in less than a year. Tr. vol. 2, 60. Moreover, witness Snider argues that NCSEA does not account for operating QFs seeking to enter into a new PPA under Schedule PP at the time their existing PPA expires that will begin immediately delivering energy at the conclusion of the prior contract term. *Id.* at 61.

In direct testimony DENC witness Petrie testified that NCSEA's assertions regarding the timeline QFs will likely come online are not supported and that many QFs eligible for Sub 158 rates have planned ahead, started the interconnection process, and will come online this year. He also testified that NCSEA's proposal was impractical and inefficient to administer, particularly for standard contracts. Moreover, witness Petrie argued that the proposal itself is arbitrary because the assumed in-service date would change in each avoided cost proceeding and is not based on any standard. Tr. vol. 5, 30.

Regarding negotiated contracts, witness Petrie further stated that the proposal by NCSEA witness Johnson that the Utilities calculate capacity costs for negotiated projects individually based on projected in service date and present a range of rates based on different in-service dates should be rejected because the process would also be inefficient and would likely lead to disagreements about in-service dates. *Id.*

In his direct testimony Public Staff witness Hinton stated that the Public Staff does not support NCSEA's recommendation for the December 31, 2021 presumed in-service date because the utilities filing of their avoided cost rates is designed to provide a predictable and certain point in time from which the avoided cost rates can be calculated and should be reflective of the utilities' current estimate of the inputs in the calculations at that time. He stated that the Public Staff agrees with Duke that smaller facilities may be able to take advantage of the Section 3 Fast Track and Supplemental Review processes under the NCIP and may not be subject to long delays in the interconnection queue. He further stated that the Public Staff recommends that the Utilities clarify when an existing QF seeking to renew its PPA can establish a new LEO for both calculating its rates and determining when the facility will be eligible to receive a capacity payment. Tr. vol. 6, 314-16.

In his direct testimony NCSEA witness Johnson stated that NCSEA is raising this issue for the first time in this proceeding because the impact of an inaccurate in-service date has become "more evident and more serious." Witness Johnson agreed that QFs proceeding under the fast track and supplemental review process can proceed more expeditiously and may warrant an earlier in-service assumption for smaller projects. Another solution would be for the Commission to publish a schedule of rates that specifies the applicable rate for all projects signing a contract during the biennial period where each QF would receive a rate based on it actual in-service date. Tr. vol. 6, 216, 222.

Witness Johnson testified that unrealistically early in-service dates results in QFs being compensated for avoided energy costs based on lower gas prices associated with earlier years than when the QF will be producing power. The problem is particularly severe when it comes to capacity costs because the Commission is now including zeros in the capacity cost calculation, and capacity may be excluded during certain years of the contract. Tr. vol. 6, 217.

Witness Johnson responded to witness Petrie's testimony that he offered no support for his assertion that few QFs will seek to establish LEOs under new rates, stating that QFs are reluctant to commit to a LEO unless and until they have a reasonable degree of certainty that their project will be economically viable. Witness Johnson stated that he was not proposing that December 2021 would align with every QF's actual in-service date, but rather his goal was to propose a more realistic date than January 2019. A more realistic date would be one where roughly half the QFs have an actual in-service date before the date and roughly half have an actual in-service date after the date. *Id.*

Regarding negotiated contracts, witness Johnson rebutted DENC's concerns that there would be difficulties in negotiations because his recommendation was that rates be tied to the actual in-service date and not a projected in-service date. Witness Johnson stated that this reduces or eliminates any risk of under-payment or over-payment and, if rates are tied to an actual in-service date, there would no reason to anticipate difficulties in negotiations. Tr. vol. 6, 224.

Witness Hinton agreed with NCSEA that it is appropriate for a utility and QF negotiating a PPA to agree to a presumed in-service date for rate calculation purposes that takes into account any extended timelines that may affect the project coming online. He also testified that it is consistent with N.C.G.S. § 62-156(c) and the Commission's March 6, 2015 Order on Clarification issued in Docket No. E-100, Sub 140 for either party to bilateral negotiations of a PPA to identify specific characteristics that merit consideration the calculation of avoided cost rates. *Id.* at 317.

In rebuttal testimony, witness Snider agreed with witnesses Petrie and Hinton that using a later in-service date or requiring the Utilities to publish and update multiple pricing schedules as recommends by NCSEA would inject uncertainty into the process. Tr. vol. 2, 110.

DENC witness Petrie on rebuttal also stated that DENC agrees with the Public Staff that a later in-service date should not be assumed for standard offer QFs. Furthermore, witness Petrie testified that using the January 2019 in-service date is the most administratively efficient method to develop standard rates and terms for all QFs. Alternatives to this accepted approach would add unnecessary complications and give rise to more disputes. Tr. vol. 5, 45, 53.

At the hearing, in response to questions from NCSEA, Duke witness Snider testified that with respect to negotiated contracts it is currently Duke's practice that the avoided rates included in those contracts be based on the actual projected in-service dates. Tr. vol. 3, 10.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, and for the reasons detailed by Duke and the Public Staff, the Commission finds that it is appropriate for DEC, DEP, and DENC to continue their current approach to the assumed January 2019 in-service date for the purposes of this proceeding, and that it is appropriate for the utility and a QF to negotiate a presumed in service date for rate calculation purposes taking into account any anticipated date of the QF project coming online. In making this finding of fact, the Commission gives substantial weight to the evidence and arguments of Duke and the Public Staff, which the Commission views as highly persuasive. The Commission further finds that the Utilities' historical practice is appropriate for use in this proceeding. The Commission also agrees with the Public Staff that this issue may become more important as more QF contracts approach their expirations. Therefore, the Commission will require the Utilities to provide further justification for the timeline of the delivery of the Notice of Commitment to existing QFs in their initial filing in the next biennial avoided cost proceeding, and the Commission may further consider the issue in that proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 27

The evidence supporting this finding of fact is found Duke's verified JIS, DENC's verified Initial Statement, and the entire record herein.

Summary of the Evidence

In its JIS Duke states that for determining forecasted avoided energy costs, the Utilities are relying upon forward market price data out ten years (2019-2028), indicating its belief that these numbers provide a more precise indicator of the near-term future commodity costs of natural gas for both IRP purposes — to plan for Duke's next capacity resource option to meet customers' future energy needs — as well as for purposes of calculating avoided energy costs to be paid to QFs to avoid such future energy needs. Duke indicates that after relying on ten years of forward market data, it assumes that commodity prices begin to transition to fundamental forecast data starting in year 11. Duke indicates that since the 2016 Sub 148 Proceeding, it has purchased ten-year forward gas contracts on five separate occasions (one in 2016, two in 2017, and two in 2018) for use in its IRP and avoided cost filings and to demonstrate that forward market liquidity exists ten years into the future. Duke indicates that based on historical experience and recently transacted forward gas purchases, natural gas commodity prices are liquid ten years into the future and have continued to steadily decline, and support its position that the continued use of ten years of forward market commodity prices for both IRP purposes and in the calculation of avoided costs is prudent and reasonable. JIS at 17-21.

In its Initial Statement DENC indicates that consistent with its past practice, it developed its avoided energy rates for the first 18 months using forward market prices, for months 19 through 36 using a blend of forward market prices and a commodity forecast provided by ICF International, Inc. (ICF), and for month 37 and thereafter based on ICF prices exclusively. DENC Initial Statement at 8.

In its Initial Comments the Public Staff states that it analyzed the methodologies used by other utilities around the country by reviewing other utility IRPs and did not identify any utilities other than DEC and DEP that rely wholly on forward prices for terms greater than six years. The Public Staff also notes that Duke Energy Florida, Duke Energy Kentucky, and Duke Energy Indiana in their IRPs each rely wholly on market prices for the first five years, blend market and fundamental prices for the next five years, and switch to the fundamental forecast for the remainder of the planning period. The Public Staff notes that Duke did not purchase ten-year forwards as a standard part of its fuel procurement practices, and its ability to purchase ten-year forwards on five occasions in the past three years should not be determinative as to whether the use of ten-year forwards is appropriate. Therefore, the Public Staff recommends that the Commission require DEC and DEP to use no more than five years of forward market data before transitioning to Duke's fundamental forecast. Public Staff Initial Comments at 21-28.

SACE notes in its Initial Comments that the Commission in the 2016 Sub 148 Order directed DEC and DEP to "recalculate their avoided energy rates using forward natural gas prices for no more than eight years and fundamental forecasts for the remainder of the planning period," and that contrary to this directive Duke relied on ten years of forward natural gas market price data. SACE Initial Comments at 6 (citing 2016 Sub 148 Order, Ordering Paragraph No. 5). SACE further states that reliance on long-term forward pricing is inappropriate because future markets, which are highly responsive to short term and temporary trends, are not good indicators of long-term market trends. SACE also notes that the lack of trading volume for NYMEX gas futures more than two to three years ahead prohibits prices from being robust forecasters of gas prices, and states that long-term forecasts should not be based on short-term trends, but instead on more stable factors such as resource base and expected production costs. SACE recommends that the Commission require Duke to rely on no more than two to three years of forward market price forecasts before transitioning to a blended price forecast, and then a fundamental price forecast. SACE also indicates its general support for the approach utilized by DENC. SACE Initial Comments at 6-7.

In its Initial Comments NCSEA proposes that the Utilities use forward market prices for two years before transitioning over the next three years to an average of a set of recent fundamentals forecasts, including the ICF forecast and the 2019 EIA Annual Energy Outlook forecast. NCSEA further notes that Duke's current hedging policies do not allow the companies to buy quantities of natural gas at 10-year fixed prices to displace solar generation. NCSEA does state, however, that it would not object in the alternative to use of the forecast methodology used by DENC. NCSEA Initial Comments at 17-19. NCSEA witness Beach also notes in his affidavit that "[t]he DEC/DEP transactions are with financial institutions that may have a limited pool of counterparties for these transactions, but the utilities have not provided evidence of a deep and transparent market for 10-year gas transactions at fixed prices," and further notes that Henry Hub Forward Market Open Interest on January 10, 2019, showed that only "99.0% of the open interest is in the first two years" and that there are "small and sporadic volumes traded in the out years." Beach Affidavit at 11.

In its Reply Comments DENC states that its reliance on the ICF forecast to forecast energy prices in avoided cost proceedings has been accepted by the Commission since the 2012 avoided cost proceeding, Docket No. E-100, Sub 136 (2012 Sub 136 Proceeding), and continues to be appropriate. DENC notes that the ICF forecasts are reputable and respected in the industry and that the nationwide EIA forecast does not provide the same level of regional pricing information on which to base forecasted fuel prices in this proceeding. DENC Reply Comments at 3-5.

In its Reply Comments SACE indicates that it considers the proposals of both the Public Staff and NCSEA be more appropriate than the natural gas forecast methodology proposed by Duke. SACE Reply Comments at 3. The Small Hydro Group indicates that it agrees with the Public Staff that the Commission should require Duke to use no more than five years of forward market data before transitioning to its fundamental forecast. Small Hydro Group Reply Comments at 3.

In its Reply Comments Duke recognizes that the Commission declined to approve Duke's forecasts in the 2016 Sub 148 Proceeding and emphasized the importance of internal consistency between the Utilities' IRPs and the biennial avoided cost proceeding. Duke also acknowledges that the Commission was not fully persuaded that the market was sufficiently liquid to support ten-year futures but indicates its intention to continue to monitor liquidity in the natural gas market in future avoided cost proceedings. Duke Reply Comments at 11-12.

Responding to the Public Staff's analysis of other utilities' IRPs to support its argument, Duke indicates that the fundamental purpose of integrated resource planning differs from fixing forecasted avoided cost rates under PURPA, and that the Public Staff's reliance on the fuel procurement practices used by other utilities in the development of their IRPs is misplaced. Duke also notes that since the time of filing of Initial Comments, it has identified another North Carolina market participant that has also purchased significant quantities of ten-year forward natural gas, providing additional evidence of liquidity in the ten-year forward natural gas market. *Id.* at 13-16.

In response to NCSEA's comments regarding the limited number of NYMEX futures contracts with terms longer than two years, Duke reiterates its position from the 2016 Sub 148 Proceeding, that the terms of exchange transactions should not be viewed as evidence for market liquidity for longer-term transactions; rather, market liquidity is demonstrated by readily available long-term natural gas forward contracts in bilateral markets as demonstrated by the transactions and price quotes entered into by Duke and other entities in North Carolina. *Id.* at 16.

In response to SACE's comments that natural gas markets are too subjective to short-term influences to rely on ten-year forward prices for avoided cost purposes, Duke indicates its disagreement and notes that for the past few years, fundamental gas forecasts have lagged the market and have actually been more inconsistent year-over-year than the actual transactable market place over the past five years. Duke recommends that the Commission approve Duke's proposed use of ten-year forward market prices. *Id.* at 18.

Discussion and Conclusions

The evidence in this proceeding demonstrates continued declines in the price of natural gas. In addition, the evidence demonstrates that forecasts, while not directly derived solely from market prices, are highly influenced by market activity, and that changes in the liquidity and trading prices in the natural gas markets over the long term are being incorporated into long-term forecasts. In the 2016 Sub 148 Proceeding the parties advocated for many of the same positions as in this proceeding. In the 2016 Sub 148 Order the Commission found merit in some of the arguments raised by each party, and in its expert judgment adopted a method for the purposes of that proceeding that authorized Duke to rely on market data for eight years and fundamental forecasts thereafter. The Commission also indicated that it would continue to monitor the liquidity of the market in future avoided cost proceedings.

In this proceeding the Commission again recognizes the important relationship that exists between the Commission's biennial avoided cost proceeding and the Commission's review of IRPs, as well as the importance of maintaining internal consistency between these proceedings. In this proceeding and in the IRP proceeding, the Public Staff argues that Duke's reliance on ten years of forward market price data tends to lead to gas price forceasts lower than is appropriate, which may lead to an excessive reliance on natural gas-fired generation relative to other forms of generation — such as solar and battery storage. The Public Staff instead proposes the use of forward prices for no more than five years, combined with a fundamental forecast, arguing that after year five the current market is not sufficiently robust to supplant the predictions of market analysts. The Commission finds somewhat persuasive the Public Staff's evidence demonstrating that Duke's other operating utilities do not use ten years of forward prices and that the practice proposed by Duke is highly uncommon in the electric utility industry. NCSEA and SACE argue in favor of less reliance on forward market price data, or in support of the Public Staff's position.

After careful consideration, the Commission is not persuaded that a change in the fuel forecasting methodology approved in the 2016 Sub 148 Order is appropriate, at this time. While the parties who have addressed this issue produced substantial, competent, and material evidence and well-articulated arguments in support of their positions, this evidence does not definitively support movement in either direction between fundamental forecasting and forward-market purchases. Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate to require DEC and DEP to continue to calculate their respective avoided energy costs using forward contract natural gas prices for no more than eight years before using fundamental forecast data for the remainder of the planning period. The Commission also recognizes that DENC's fuel forecasting methodology is generally in alignment with the fuel forecasting practices by other utilities identified by the Public Staff and reflects a reasonable balance between the weight given to both forward market purchases and longer-term fuel price forecasts. Therefore, the Commission finds that the fuel forecasting methodology utilized by DENC is also appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 28

The evidence supporting this finding of fact is found in Duke's verified JIS, Public Staff's Initial Comments, NCSEA's Initial Comments, SACE's Initial Comments, Cube Yadkin's Initial Comments, Duke's Reply Comments, and the entire record herein.

Summary of the Evidence

In its JIS Duke argues that PURPA provides a QF a "Put Option" to sell at its sole discretion. Furthermore, Duke maintains that a QF would normally compensate Duke for taking on the role of obligating the utilities to purchase from the QF, regardless of the prevailing market value at the time of the exercise. Duke states that the value of this "Put Option" offsets the hedging value from the reduced fuel price volatility inherent with renewable generation, and therefore Duke did not include a hedging value calculated in a similar manner to the rates included in prior proceedings. JIS at 22-23.

In its Initial Comments the Public Staff disagrees with Duke's argument, stating that Duke's position "would essentially require QFs to compensate utilities for the right to sell their generation." Public Staff Initial Comments at 28. The Public Staff states that renewable generation provides additional fuel price stability that has value, as evidenced by the Utilities' ongoing hedging programs, and that it is reasonable to expect that the utility will be able to reduce its volume of hedged natural gas and coal fuels as a result of renewable generation. The Public Staff reiterates its support for inclusion of a hedging value for renewables, consistent with the Commission's findings in the Sub 140 Phase One Order, and recommends that the Commission require DEC and DEP to calculate and include the fuel hedging benefits associated with purchases of renewable energy in their avoided energy cost rates using the Black-Scholes Option Pricing Model or similar method. *Id.* at 29.

NCSEA states its continued support for the inclusion of a hedging value, finding that QFs not only displace natural gas-fired generation and reduce the Utilities' use of natural gas but also decrease the exposure to natural gas price volatility by providing a long-term physical hedge for the term of the PPA. NCSEA finds, however, that the use of the Black-Scholes approach that reprices gas at the prevailing market price repeatedly over a ten-year period undervalues the hedge provided by a ten-year PPA with prices fixed from the start of the contract's term. NCSEA indicates that it reviewed several alternative methods used by other utilities that are superior to the current method and would result in higher avoided fuel hedging values. NCSEA Initial Comments at 20-27.

SACE states that it disagrees with Duke's proposal to eliminate the existing hedging value from its avoided energy rates, noting its disagreement with Duke's argument that PURPA creates a "Put Option" for QFs to sell to the utilities at avoided cost rates as inconsistent with the general principles in PURPA to grant QFs the right to sell energy and capacity to a utility at its avoided costs, as determined at the time the LEO is created. SACE Initial Comments at 7-10.

Cube Yadkin states that Duke's proposal to eliminate the hedging value from its avoided energy cost calculations misunderstands, if not misrepresents, the purpose of fuel hedging, stating that the purpose of fuel hedging is to insulate ratepayers from fuel volatility. Cube Yadkin states that "the fact that natural gas prices did not rise but instead declined does not mean that the hedge had no value — any more than an insurance policy that never has to pay out a claim has no value." Cube Yadkin Initial Comments at 4. Cube Yadkin notes that the main objective of a utility's fuel hedging program is to reduce customer exposure to fuel price volatility, not to reduce fuel costs. Citing recent proceedings in Florida and Ohio where other Duke Energy entities noted that downward trend in natural gas market prices experienced over the last several years would not continue indefinitely, Cube Yadkin states that the hedge against fuel price volatility continues to have economic value and should be compensated. *Id.* at 4-5.

In its Reply Comments Duke states that the arguments raised by NCSEA and the Public Staff are internally inconsistent in that they challenged the discrepancies between DEC's and DEP's fuel procurement policies and the forward natural gas positions relied on in the avoided cost and IRP proceedings, but then supported the utilities being obligated to purchase QF power at prices based on ten-year duration gas without making equivalent changes to their fuel procurement practices. Duke states that "to hold gas procurement to one standard and power procurement to another simply represents an artificial arbitrage opportunity to the detriment of consumers." Duke Reply Comments at 20. Duke states that to highlight the value of this cost being borne by customers, it sought a price quote for a put option on a fixed ten-year natural gas transaction that does not expire for two years. Duke indicates that that the put option premium quote was equivalent to the right provided by a QF to sell to the utilities without obligation. Duke further indicates that including the premium results in an overpayment by customers to QFs, contrary to PURPA, since avoided cost prices paid to QFs already reflect Duke's fixed and avoidable cost of natural gas over a ten-year term. Duke notes in closing that it has identified only one other jurisdiction that has accepted hedging value as an avoidable cost, and that the alternative methods for determining the hedging value of renewable resources identified by NCSEA have not been applied in other jurisdictions. Therefore, a requirement that the Utilities include an avoided hedging cost adder would make North Carolina an outlier compared to methodologies employed by other states to determine avoided cost under PURPA. *Id.* at 23-30.

Discussion and Conclusions

In the Sub 140 Phase One Order the Commission found that renewable generation provides fuel price hedging benefits because a utility's purchase of energy from a QF reduces the amount of fuel the utility otherwise would need to purchase. In doing so, the Commission acknowledged that purchasing solar power can be seen as the equivalent of buying natural gas forwards. Based upon the foregoing and the entire record herein, the Commission finds that the evidence in this proceeding demonstrates again that there are fuel price hedging benefits associated with renewable generation. Purchases from QFs are substitutes for the purchase of fuels and reduce the amount of fuel that must be purchased and, therefore, the costs that the utilities would incur toward fuel procurement. In making this finding, the Commission gives substantial weight to the comments and arguments of the Public Staff, SACE, Cube Yadkin, and NCSEA on this issue. The Commission agrees with Cube Yadkin that the value of the hedge is to insulate ratepayers from fuel volatility, and that the hedge value is appropriate for inclusion in avoided cost rates.

The Commission is not persuaded that Duke's argument that QFs are inappropriately being granted a "put option" without any obligation to sell is consistent with the requirements of 18 C.F.R. § 292.304(d)(2), which provides that a QF may choose to sell energy or capacity pursuant to a LEO for delivery "over a specified term," with rates determined at the time the obligation is incurred. Further, pursuant to N.C.G.S. § 62-156(b)(2):

> A determination of the avoided energy costs to the utility shall include a consideration of the following factors over the term of the power contracts: the expected costs of the additional or existing generating capacity which could be displaced, the expected cost of fuel and other operating expenses of electric energy production which a utility would otherwise incur in generating or purchasing power from another source, and the expected security of the supply of fuel for the utilities' alternative power sources.

The Commission is likewise not persuaded that Duke's view is consistent with this direction, nor is the Commission persuaded by Duke's position that paying QFs for the value of reduced volatility with fuel prices subjects its customers to additional overpayment risk. Instead, based upon the foregoing and the entire record herein, the Commission finds, consistent with the Public Staff's arguments, that DEC and DEP should be required to recalculate their avoided energy rates to include an appropriate fuel hedging value utilizing the Black-Scholes Model or a similar model to determine the hedging value of renewable generation, and that the fuel hedge value should be included for each year of the entire term of the QF PPA.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 29 – 31

The evidence supporting these findings of fact is found in Duke's verified JIS, NCSEA witness Beach's Affidavit, and the entire record herein.

Summary of the Evidence

Duke's JIS notes the Commission's direction in the Sub 140 Phase One Order to continue to study the potential impacts of integrating increasing levels of solar resources into Duke's generation mix and contends that the increased levels of uncontrolled solar QF generation are resulting in increased operating costs relative to dispatchable generation resources. While Duke continues to recognize an avoided energy line loss adjustment for distribution-interconnected QFs and supports identified integration costs associated with increasing penetrations of variable and non-dispatchable solar capacity, it does not identify any avoidable transmission or distribution capacity benefits associated with QF generation in quantifying avoided cost. JIS at 31-32.

In its Initial Comments NCSEA contends that solar integration allows utilities to avoid future transmission and distribution capacity costs and asserts that these "benefits" should be considered when developing Duke's avoided cost rates. NCSEA relies on the affidavit of Thomas Beach filed in support of its Initial Comments to argue that small QF generation can reduce peak loads on the Utilities' upstream distribution and transmission systems, thereby allowing the Utilities to avoid the need to expand the entire transmission and distribution system and to avoid future load related transmission and distribution capacity costs. NCSEA Initial Comments at 39-43.

NCSEA witness Beach proposes quantifying avoided transmission and distribution costs by allocating avoided transmission and distribution costs "to the hours of the year, using peak capacity allocation factors (PCAFs) based on the hours when loads on the transmission and distribution system are highest." He explains that the PCAF-based allocation of avoided distribution costs uses a sample of loads at DEC's and DEP's distribution substations and that analyzing this data is a first step toward including more locational granularity in avoided cost rates to quantify transmission and distribution costs that could be avoided by purchases from distribution-connected QFs. NCSEA witness Beach's PCAF analysis was developed based on the avoided transmission and distribution capacity costs that Duke has relied upon for purpose of quantifying the avoided transmission and distribution capacity value attributed to Duke's DSM programs and energy efficiency (EE) programs. Beach Affidavit at 7, 21-26.

The Public Staff's Initial Comments highlight the Commission's discussion in the Sub 140 Phase One Order that integration of solar resources into a utility's generation mix can result in both costs and benefits, but that it is "inappropriate for ratepayers to shoulder such costs [as includable in avoided costs] until they become known and verifiable." The Public Staff comments that it may be appropriate for the Commission to consider evidence from other parties as to what additional costs or benefits can be sufficiently known and verifiable at this time such that they should be included in avoided cost rates. Public Staff Initial Comments at 32-33.

In its Reply Comments the Public Staff reintroduces Dr. Richard Brown's testimony on behalf of the Public Staff from the 2014 Sub 140 Proceeding addressing the theoretical potential for QFs to avoid future transmission and distribution capacity investments. The Public Staff details that, theoretically, a renewable energy facility can be located on an existing transmission system at a place that can reduce power flows on heavily loaded transmission lines. However, the Public Staff also notes that the ability of a facility to provide this benefit will be very site-specific.

Similarly, distribution-connected renewable energy facilities could potentially help reduce future transmission capacity expenditures, if their power does not flow onto the transmission system. Public Staff Reply Comments at 9.

The Public Staff also recognizes, however, that the significant increases in distributed generation facilities interconnecting to the distribution and transmission system in North Carolina in recent years raises additional questions regarding the proper allocation and assignment of costs associated with use of the grid. The Public Staff specifically cites to Public Staff witness Jay Lucas' recent testimony in Docket No. E-100, Sub 101 regarding the additional system costs being imposed on retail customers to integrate QF solar generators to support their argument. Public Staff Reply Comments at 9-10.

The Public Staff also comments that offering an avoided transmission and distribution cost adder to all QFs eligible for the standard offer would likely not incentivize such QFs to locate in places that are more likely to result in future avoided transmission and distribution investments. In support of this contention the Public Staff states that an avoided transmission and distribution benefit offered to all Standard Offer QFs would ignore the site- and project-specific considerations that are critical to an accurate assessment of potential avoided transmission and distribution system benefit. Public Staff Reply Comments at 10.

The Public Staff finds that evidence was lacking to warrant an avoided distribution capacity cost adder for either distribution or transmission connected QFs. However, the Public Staff argues that it may be appropriate for the Utilities to calculate an avoided transmission cost adder to the avoided energy rate applicable to a standard offer contract, with a provision within the contract allowing the utility to remove the availability of the avoided transmission adder if (i) the QF would cause or exacerbate reverse power flow, or (ii) the projected load growth on the interconnected feeder over a ten-year time horizon was negative or negligible. The Public Staff states that the goal of provision (i) is to ensure that a QF interconnecting to a distribution feeder that is experiencing backfeeding will not receive avoided transmission benefits, and that provision (ii) would ensure that a QF interconnecting to a feeder that is experiencing little to no load growth, and thus is not expected to make load growth-related transmission upgrades in the foreseeable future, does not receive avoided transmission benefits. Public Staff Reply Comments at 10. Specific to the standard offer contract, the Public Staff recommends that the Commission direct the Utilities to calculate a conditional avoided transmission capacity cost adder for standard offer contracts, which can be removed if certain conditions are met regarding backfeeding and load growth. Public Staff Reply Comments at 9-11.

The Public Staff also supports QFs not eligible for the standard offer contract being able to quantify site- and project-specific characteristics to show that the QF's operations create future avoided transmission capacity benefits and to include those avoided system costs in their negotiated contracts. Specific to negotiated QF avoided costs, the Public Staff recommends that the Utilities consider site- and project-specific characteristics during contract negotiations with QFs not eligible for the standard offer contract, and that an avoided transmission adder be included if such a project can provide real and measurable avoided transmission capacity benefits. Public Staff Reply Comments at 11.

In response to NCSEA's proposal the Public Staff states that it has concerns with the use of the avoided transmission and distribution rates from the DSM/EE proceedings as it is not clear that those rates, which were calculated based upon the availability of DSM during system peak and EE during all hours, are applicable to QFs. Public Staff Reply Comments at 11-12.

In its reply comments SACE agrees with NCSEA that QFs should be compensated for the full range of costs that they allow the purchasing utility to avoid, including applicable transmission and distribution costs. SACE notes that the FERC previously upheld a state utility commission's authority to include an avoided cost "adder" for transmission-connected QFs located in transmission-constrained areas to reflect the savings from the deferred transmission- and distribution-related costs. Therefore, SACE argues that NCSEA's proposed avoided transmission and distribution system cost analysis is consistent with the FERC's precedent on the issue under PURPA. SACE Reply Comments at 13-14.

Duke's Reply Comments provide that PURPA's foundational "but for" premise prescribes that a utility should pay QFs its full avoided costs but cannot be required to pay a QF more than the cost the utility would incur if the utility generated the power or purchased it from another source. Citing prior guidance from the FERC evaluating what constitutes a utility's avoided costs under PURPA, Duke comments that costs which are speculative or otherwise not measurable or quantifiable are inappropriate in arriving at the utility's avoided costs, whereas costs actually incurred by the utility that are quantifiable and "real" are appropriately considered in arriving at a utility's avoided costs. Duke Reply Comments at 126-27.

In response to NCSEA, Duke argues that including an adder for future avoided transmission and distribution costs in the standard offer would be unprecedented under PURPA due to the generalized and speculative nature of "potential" future transmission and distribution system costs advocated by NCSEA as avoidable. Duke asserts that the FERC has accepted only "an actual determination of the expected costs of upgrades to the distribution or transmission system that [purchasing from QFs] will permit the purchasing utility to avoid," where the adder reflected the utility's avoided future cost of constrained transmission and distribution infrastructure that would be required to deliver power to a transmission-constrained area. Therefore, Duke rejects NCSEA's PCAF analysis as a generalized quantification of estimated "time varying locational values" of load reductions across DEC's and DEP's entire distribution systems, which in no way correlates to or represents the expected cost of upgrades to the utility's system that theoretically could be avoided by purchasing from QFs. Accordingly, Duke argues that it has properly excluded the potential that purchasing energy from standard offer QFs might avoid some level of future system transmission and distribution costs in developing the avoided cost rate calculations. Duke Reply Comments at 126-27.

Duke also asserts that the system impact of distribution-connected QFs and DSM/EE program are not comparable. Unlike solar generation, DSM/EE measures are permanent changes in load that do not diminish with cloud cover or other conditions that impact the availability of intermittent generation. If the DSM/EE measure fails, this typically results in the entire load-reducing benefit from the measure being removed from the system as opposed to the increased circuit load that would be experienced when generation fails (or is not available due to intermittency of generation output). Accordingly, Duke argues that while avoided transmission and distribution benefits can potentially be realized from customer-sited EE measures, intermittent generation does not provide the same benefit. Duke Reply Comments at 128-30.

Next, Duke asserts that the Companies design their transmission and distribution systems to meet peak load on the circuit and at the substation. Due to the intermittent and daytime nature of solar generation, Duke cannot rely upon QF solar being available to meet peak load, and therefore cannot reasonably assume any load reduction due to QF solar that could support the downsizing of Duke's transmission and distribution assets. Moreover, Duke asserts that distribution and transmission planners do not reduce the capacity of installed facilities due to concerns that circuits will be overloaded if generation is unavailable or intermittent during peak conditions. Duke Reply Comments at 129-30.

Duke then argues that if anything, QFs have benefitted by consuming available distribution and transmission capacity up to the limits of the existing system, as exemplified by the fact that in some areas, QF generation exceeds load and exporting from the region is constrained in some hours. In conclusion, Duke reiterates that it has properly concluded that there presently are no real or quantifiable costs of future avoided transmission and distribution or benefits resulting from solar installations and contends that it would be more reasonable for the Commission to recognize that incremental QF energy on the distribution system could actually increase future transmission and distribution costs, noting statements by the Public Staff expressing concern as to whether solar QFs were properly bearing the representative responsibility of increased grid O&M costs. Thus, Duke recommends the Commission reject NCSEA's proposal. Duke Reply Comments at 130-31.

Discussion and Conclusions

The Commission has carefully considered NCSEA's proposed avoided transmission and distribution adder, as well as the evidence in rebuttal to NCSEA's proposal, and finds persuasive Duke and the Public Staff's arguments that NCSEA's proposal should not be adopted in this proceeding. The Commission agrees with the Public Staff that the significant increase in QFs interconnecting in North Carolina in recent years has raised questions regarding the proper allocation and assignment of costs associated with the use of the grid. On this issue, the Commission gives weight to the comments of Duke and the Public Staff addressing this issue.

Specific to NCSEA's proposal, the Commission finds persuasive Duke's arguments that relying upon generic assumptions about future avoidable transmission and distribution system investments based upon witness Beach's PCAF analysis is inappropriate and fails to accurately quantify specific costs that would be avoided as a result of purchasing energy and capacity from QFs. PURPA requires that costs must be quantifiable and "real" to be included in avoided costs. *Cal. Pub. Utility Comm'n.*, 132 FERC ¶ 61,047, 61,267-68, *clarification granted & reh'g denied*, 133 FERC ¶ 61,059 (2010), *reh'g denied*, 134 FERC ¶ 61,044 (2011). Similarly, the Utilities' avoided costs must be "known and measurable," and the Commission "should not rely on conclusions derived from limited observations or speculation to definitively establish the parameters of what should be included in avoided cost rates." Sub 140 Phase One Order at 61. The Commission agrees with Duke that witness Beach's analysis presents a generalized quantification of estimated "time-varying location values" of load reductions across DEC's and DEP's entire distribution systems and not a quantifiable or known and measurable quantification of Duke's expected cost of system upgrades that could be avoided from purchasing power from specific QFs.

The Commission also finds persuasive Duke's arguments that excluding the potential that purchasing energy from standard offer QFs might avoid some level of future transmission or distribution costs in developing the avoided cost calculation is similar to avoided cost calculations in other jurisdictions. NCSEA has not identified other jurisdictions as including such an adder to generic avoided cost rates for avoided transmission or distribution costs, even though utility systems with lower penetrations of distribution-connected generation would theoretically achieve greater benefits from these distributed energy resources in terms of avoiding the need for potential future transmission or distribution system investments. In addition, the Commission agrees with the Public Staff and Duke's conclusion that the use of avoided transmission and distribution assumptions for DSM/EE resources and measures, as proposed by NCSEA, is not reasonably representative of the system impacts and capacity contribution of distribution-connected QFs. The Commission also agrees with Duke that due to the intermittent and daytime nature of solar generation, Duke cannot rely upon QF solar being available to meet peak load and, therefore, cannot reasonably assume any load reduction due to QF solar that could support the downsizing of transmission and distribution assets. The Commission also finds persuasive Duke's explanation that DSM/EE measures are permanent changes in load that do not diminish with cloud cover or other conditions that impact the availability of intermittent generation. In short, intermittent QF generation does not provide the same quantifiable benefit of reducing load on the distribution system during the utility's peak periods as DSM/EE measures.

Finally, the Commission finds persuasive Duke's arguments that the growth of QF solar in North Carolina could potentially increase transmission and distribution costs for retail customers. In addition, the Public Staff cites to its testimony in Docket No. E-100, Sub 101 addressing this issue. As asserted by Duke, QFs are responsible for funding distribution system or transmission network upgrades to support their own interconnection; QFs are not obligated to acquire transmission capacity to deliver QF power to the utility's network, and instead rely upon the utility's transmission system. These arguments are consistent with and provide support for the Public Staff's contention that there is insufficient evidence to warrant avoided distribution capacity cost adders for either distribution- or transmission-connected QFs at this time. The Commission agrees, and therefore declines to adopt NCSEA's proposal.

Similarly, for purposes of this proceeding the Commission declines to adopt the Public Staff's recommendation for the Utilities to calculate a conditional avoided transmission capacity cost adder for standard offer contracts, which could be removed if certain conditions are met regarding backfeeding and load growth. As stated by the Public Staff:

> [O]ffering an avoided T&D cost adder to all QFs eligible for the standard offer contract (Standard Offer QFs) would not likely incentivize direct Standard Offer QFs to locations that are more likely to result in avoided future T&D investments. An avoided T&D benefit offered to all Standard Offer QFs would ignore the site-

> and project-specific considerations that are critical to an accurate assessment of the avoided T&D [system] benefit.

Public Staff Reply Comments at 10.

The Public Staff's comments and Duke's evidence summarized above tends to demonstrate that intermittent QFs do not generically provide firm load reductions across the system, and therefore the presence of QF-supplied power cannot support the downsizing of Duke's transmission and distribution assets. This evidence lends further support to the Commission's decision not to adopt the Public Staff's proposal. Nonetheless, the Commission appreciates the Public Staff's nuanced attention to this issue and will maintain an openness to revisit this issue in a future proceeding where the evidence can be more fully developed. The Commission anticipates greater clarity on this subject as Duke advances its Integrated Systems and Operations Planning effort currently underway that leverages the functionalities afforded by foundational grid improvement plan investments. The Commission expects that this work should inform the evaluation of avoided transmission and distribution capacity costs and benefits in future avoided cost dockets. The Commission will direct the Utilities to provide additional discussion, insights, and plans in the next avoided cost proceeding. Finally, in the negotiated contract setting, where project-specific characteristics during contract negotiations with a QF must be considered, the Commission expects the Utilities to include an avoided T&D capacity adder if a project can provide real and measurable avoided transmission or distribution capacity benefits.

Based upon the foregoing and the entire record in the proceeding, the Commission finds that it is inappropriate for the Utilities to include a transmission and distribution capacity adder within their avoided cost calculations available to standard offer QFs, and that the use of transmission and distribution capacity rates from DSM proceedings is inappropriate for use in calculating avoided transmission and capacity costs in this proceeding. The Commission further finds that the Public Staff's proposed conditional avoided transmission cost adder is not sufficiently supported nor fully developed at this time, and therefore the Commission determines to not approve this recommendation. However, the Commission will direct the Utilities and the Public Staff to work together to more precisely define these issues for the Commission's consideration in the next avoided cost proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 32

The evidence supporting this finding of fact is found in Duke's verified JIS and the entire record herein.

Summary of the Evidence

NCSEA advocates for the Utilities to include a market price suppression adder to their avoided energy cost calculations. NCSEA argues that integrating renewables in regional power markets causes a "reduction in demand [that] will cause a corresponding reduction in the price in these markets, which benefits the Utilities when each must buy power or natural gas in these markets." NCSEA suggests that increasing penetrations of renewables "causes the prices of energy to reduce across the country, on a whole," and therefore concludes that the Commission should "require the Utilities to account for such market changes caused by distributed energy resources." NCSEA Reply Comments at 34.

In its Reply Comments Duke argues that NCSEA's proposal to include a "market price suppression" adder in avoided costs was in no way based upon known and measurable costs actually avoided by Duke's procurement of alternative energy. Duke contends that even assuming NCSEA's point — that increasing renewables in regional power markets impacts electricity and natural gas prices in those markets — has some validity, NCSEA ignores numerous other factors that have significantly greater impacts on the market price of energy, including, but not limited to natural gas production costs, weather, and environmental regulations. Moreover, Duke responds further that the market price of energy that is avoidable by Duke is precisely that — a market price — and reflects both higher and lower cost resources (such as DEC and DEP's combined 9,100 MW (winter) of baseload, low variable cost nuclear generation). Duke states NCSEA's recommendation for Duke and DENC to account for inclusion of above-market "price benefits" of integrating renewables in their avoided costs is speculative, unquantified, and not reflective of costs actually avoidable by the utility. Duke concludes that accepting above-market adders in calculating Duke's cost of energy essentially forces Duke to pay avoided energy rates that are above the Utilities' forecasted incremental cost of procuring alternative energy, which is inappropriate under PURPA. Duke Reply Comments at 29-30.

Discussion and Conclusions

The Commission agrees with Duke that NCSEA's proposed "market price suppression adder," designed to capture a decrease in wholesale power prices due to the increasing integration of renewable QFs, is not based upon known and measurable costs that can accurately be calculated to include in the Utilities' avoided energy costs. Therefore, based upon the foregoing and the entire record in the proceeding, the Commission finds that it is not appropriate for the Utilities to incorporate a market price suppression adder in their avoided cost calculations for this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 33 – 42

The evidence supporting these findings of fact is found in Duke's verified JIS; the testimony of Duke witnesses Snider, Wheeler, and Wintermantel, SACE witness Kirby, NCSEA witness Beach, Public Staff witness Thomas; and the entire record herein.

Summary of the Evidence

Duke's JIS provides that the 2018 Scheduling Order directed the Utilities to consider factors relevant to the characteristics of QF-supplied power — specifically intermittent and non-dispatchable power — in designing rates to meet PURPA's objectives of appropriately valuing Duke's incremental costs of alternative energy to be avoided from purchasing power from a QF. Further, the 2016 Sub 148 Order similarly emphasized that it would be appropriate for the Utilities to propose schedules specific to QFs that provide intermittent, non-dispatchable power if the Utilities' cost data "demonstrates marked differences" in the value of the energy and capacity provided by these QFs. JIS at 30-31 (quoting 2016 Sub 148 Order).

In response to these Commission directives, Duke argues that the costs avoided by growing levels of solar QFs that provide intermittent, non-dispatchable power is markedly different from integrating firm power and that it is appropriate to recognize integration costs that Duke is now incurring in valuing the energy and capacity provided by QFs eligible for Schedule PP. Based on Duke's recent experience integrating surging levels of variable and intermittent solar QF power, Duke has included an integration services charge in its rate design to reflect the impact on operating reserves, or generation ancillary requirements, for new variable and non-dispatchable solar capacity. JIS at 30-31; tr. vol. 2, 38.

The JIS and the testimony of witness Snider explain that that meeting its obligation to provide reliable electric service to its customers requires Duke to dispatch DEC's and DEP's generation fleet resources to meet real-time load on a moment-to-moment basis. Witness Snider testified that the energy output from solar resources is variable, and that it can unexpectedly and rapidly drop-off or ramp-up in real-time, thereby increasing uncertainty in day-ahead, hourly, and sub-hourly projections for fleet operations. The addition of solar volatility to the system increases the real-time volatility the system experiences as compared to just servicing load without solar on the system. Witness Snider stated that this additional uncertainty and volatility requires Duke to carry additional operating reserves, which are the real-time system resources required to balance and regulate the system on an hourly and sub-hourly basis. These operating reserves are provided by reserving additional dispatchable conventional fleet resources to ensure that sufficient operational flexibility is available to respond in real-time to rapid changes in solar output. Additionally, ensuring that sufficient operating reserves are available is also required to maintain compliance with NERC bulk electric system balancing and reliability standards. The need for increased real-time system operating reserves to reliably integrate increased levels of uncontrolled must-take solar generation results in additional operating costs relative to integrating a dispatchable or baseload generation source. As solar penetration increases, the cost to integrate these variable and intermittent resources while maintaining operational reliability also increases. JIS at 32-33; tr. vol. 2, 78-81.

To quantify the increasing costs of integrating solar generation into the DEC and DEP systems, witness Snider testified that Duke commissioned Astrapé Consulting (Astrapé) in late 2017 to analyze the impacts of integrating solar into Duke's systems at varying solar penetration levels and to quantify the cost of utilizing the DEC and DEP conventional fleets to provide the additional operating reserves or generation "ancillary services" needed to reliably integrate the various levels of intermittent solar generation. Tr. vol. 2, 80-81.

Duke witness Wintermantel testified in support of the Astrapé Solar Ancillary Services Study (Astrapé Study). He began by describing the integration challenges utilities experience as solar penetration increases on the utilities' systems. As solar penetration increases, the uncertainty and intra-hour volatility in net load increases, meaning five-minute deviations in net load can be much more significant in systems with high penetrations of variable and intermittent solar as compared to systems with no solar. To manage the increase in intra-hour volatility, additional load following reserves are required to allow generators additional flexibility to meet these unexpected movements in net load, which thereby increase ancillary services cost. In addition, witness Wintermantel stated that generators are forced to start more frequently, causing additional startup and maintenance costs. Tr. vol. 4, 51-56.

Witness Wintermantel then provided an overview of the SERVM model, which commits DEC's and DEP's resources on week-ahead, day-ahead, and hour-ahead bases and dispatches resources to load on a five-minute time step. For each year simulated, total production costs are then calculated and reported, as well as the reliability metrics of the system. To analyze the economic impact of integrating solar, witness Wintermantel testified that the SERVM model, which was similarly used in Duke's Commission-approved 2012 and 2016 Resource Adequacy studies, modeled Duke's system reliability with and without solar generation at various penetration levels. As detailed in the JIS, witness Wintermantel testified that this modeling analysis was performed for the 2020 study year across several solar penetrations including a No Solar scenario, the Existing plus Transition scenario (840 MW in DEC and 2,950 MW in DEP), Tranche 1 solar scenario (1,520 MW in DEC and 3,110 MW in DEP), and the Plus 1,500 MW of solar generation scenario (3,020 MW in DEC and 4,610 in DEP). Once the required ancillary services were determined, the costs of the ancillary service were also computed through the SERVM model. JIS at 32-33; tr. vol. 4, 56-59, 65-66.

Witness Wintermantel stated that an important aspect of the Astrapé Study is that the SERVM model is designed to recognize that utility system operators will have imperfect knowledge of day-ahead net load, net load a few hours ahead, and intra-hour net load to make generation commitment decisions. This imperfect knowledge is accounted for by incorporating load and solar forecast error, meaning the model commits its conventional generation fleet to a net load that has some level of error and then must adjust accordingly in real time, similar to the way system operators must adjust in real time. To mimic the movement of load and solar on a five-minute basis, the SERVM model requires one year of five-minute load and solar data as an input. For both DEC and DEP, the Astrapé Study used historical five-minute load and solar data from the 12-month period between October 2016 and September 2017. Witness Wintermantel stated that the five-minute data was scrubbed for reporting anomalies or errors and the volatility embedded in these five-minute profiles was applied to the load and solar generation for each penetration analyzed. Tr. vol. 4, 58-61.

After providing background on the Astrapé Study's inputs and modeling framework, witness Wintermantel stated that the underlying premise of the Astrapé Study is to ensure that the operating reliability of the DEC and DEP systems is the same before and after additional solar is added to Duke's systems. To study the impact on system reliability with and without solar, Astrapé utilized the $LOLE_{FLEX}$ metric of 0.1 within the model to measure the number of loss of load events due to system flexibility constraints, calculated in events per year. Witness Wintermantel testified that $LOLE_{FLEX}$ as used in the SERVM model is a measure of the system's ability to satisfy net load obligations assuming that net load is known five minutes before it materializes and provides a means of measuring if the system has enough load following reserves. As additional solar is added to the system, load uncertainty and intra-hour volatility increase, causing $LOLE_{FLEX}$ to increase. To maintain the same reliability on the system as before the solar was added, load following reserves needed to be increased. Witness Wintermantel further testified that the Astrapé Study determines the appropriate amount of load following reserves to add by forcing the system back to the original $LOLE_{FLEX}$ metric of 0.1 events per year. He clarified, however, that $LOLE_{FLEX}$ events cannot be mitigated by allowing area control error (ACE) to deviate for short periods, as $LOLE_{FLEX}$ events and ACE deviations are not synonymous. Tr. vol. 4, 62-66.

As also detailed in the JIS witness Wintermantel testified that at the Existing plus Transition solar penetration level for DEC, the Astrapé Study determined that an additional 26 MW of load following reserves were required to integrate 840 MW of solar. For DEP, the Astrapé Study identified that 166 MW of additional load following reserves were required to integrate 2,950 MW of solar. He then described Duke's use of these study results, which utilize the average costs of the Existing plus Transition solar penetrations for each utility to establish the integration services charge. Specifically, based upon the results of the Astrapé Study, Duke included a $1.10/MWh integration services charge for DEC and a $2.39/MWh integration services charge for DEP. Witness Wintermantel presented the Astrapé Study's modeling results for DEC and DEP in Figures 4 and 5 of his testimony, respectively. Witness Wintermantel also noted that Duke's proposed integration services charges for DEP and DEC were based on the lower "average" cost to integrate the Existing plus Transition solar capacity in DEP (2,950 MW) and DEC (840 MW), instead of the significantly higher "incremental" integration cost. Witness Wintermantel concluded that in his expert opinion, Duke had appropriately used the results of the Astrapé Study to establish a reasonable integration services charge. JIS at 33; tr. vol. 4, 66-74.

Duke and the Public Staff entered into the SISC Stipulation, which addresses the quantification of DEC's and DEP's ancillary services costs as well as the integration services charge rate design. Duke and the Public Staff agree in the SISC Stipulation that the Astrapé Study's data, methodology, results, and conclusions are reasonable for purposes of quantifying Duke's "average" and "incremental" ancillary services costs attributable to integrating solar generation, as well as for purposes of calculating Duke's respective integration services charges. SISC Stipulation, § III.A. The SISC Stipulation also provides that solar integration services charges collected from solar generators will be credited to ratepayers in future fuel proceedings to offset the increased fuel and fuel-related costs associated with integrating solar resources. SISC Stipulation, § IV.D.

Duke witness Wheeler testified that Duke calculated the integration services charge based upon the average integration costs for the Existing plus Transition solar capacity, as quantified by the Astrapé Study. He further stated that while Duke was proposing to use the lower average integration cost, the integration charge would be applied only to new solar generators coming onto the system, which would include QFs that establish a LEO under the biennial standard offer avoided costs rates filed in this proceeding. As existing contracts expire and new contracts are executed, this average integration services charge will apply to solar providers uniformly. Duke proposes to update the integration services charge every two years as part of the biennial avoided cost proceeding. Duke plans to continue to study the cost to integrate operating and incremental solar generation and to update the Commission on changes to the cost to integrate additional solar capacity, considering factors such as solar penetration levels, prevailing fuel prices, and the makeup of Duke's future portfolios. Witness Wheeler noted that these proposals were agreed to by the Public Staff and memorialized in Section IV of the SISC Stipulation. Tr. vol. 2, 227.

Witness Wheeler also testified in support of the integration services charge average cost rate design, explaining that all intermittent generation resources create this higher cost of service, not just new generation resources. In contrast, designing the charge to collect the incremental cost would result in preferential pricing for the first entrants while shifting cost recovery to new sellers. Witness Wheeler opposed this approach, explaining that it would be equivalent to only charging generation cost to new retail customers that cause the need for a new generator while allowing all existing customers to benefit from greater resources, which is potentially discriminatory and inconsistent with average-cost ratemaking principles. Witness Wheeler testified that he views applying the charge only to solar QFs that either establish a LEO or renew, or otherwise extend, a PPA on or after November 1, 2018, as appropriate. By delaying implementation until their current PPA expires and is subsequently renewed, witness Wheeler stated that QFs with existing contracts are protected from immediately being subject to the new charge while also ensuring that they will eventually be responsible for these increased costs if they continue to sell their generation output to the utilities. He also highlighted, however, that until their current term expires, any increased ancillary services cost that Duke incurs would be borne by retail customers. Tr. vol. 2, 230-33.

Witness Wheeler testified in support of biennially updating the integration services charge while establishing a cap on future adjustments to the charge, as recommended by the Public Staff and agreed to in Section V of the SISC Stipulation. Witness Wheeler stated that the integration services charge rate design recognizes that Duke's integration costs are expected to change with increased deployment of intermittent resources but will also vary in the future based upon actual load growth, the mix of Duke's generation resources, and potential impacts of electricity storage capability. This potential for significant changes in the future makes developing an accurate long-term estimate that would be necessary to establish a longer-term fixed rate challenging, and Duke supports biennially updating DEC's and DEP's quantification of ancillary services costs over time, subject to a cap to be approved by the Commission and included in the Schedule PP tariffs. Tr. vol. 2, 230-33.

Witness Wheeler also testified that the proposed cap on future increases to the integration services charge mitigates the risk for Sub 158 Vintage solar generators of currently unquantifiable potential future increases in DEC's and DEP's average ancillary services costs attributable to the installation of incremental solar on Duke's systems during the term of Sub 158 Vintage PPAs. Witness Wheeler testified that while the cap is not consistent with how other costs incurred to serve distributed generation are treated, Duke agreed to the cap as a reasonable approach to address the Public Staff's concerns and to offer QFs limited price certainty during their contract term. Witness Wheeler also testified that inclusion of the cap might result in some level of subsidization of QFs by the general body of customers if the average cost of these ancillary services continues to grow. Tr. vol. 2, 228.

Duke witness Wintermantel testified that he quantified the cap consistent with the methodology used in the Astrapé Study. Witness Wintermantel stated that at the direction of Duke and in support of the SISC Stipulation, Astrapé performed additional modeling simulations to calculate the incremental ancillary service cost impact of the last 100 MW of solar generation expected to be installed by the end of 2020, based upon DEC's and DEP's 2018 IRPs, to determine a potential cap for the charge, which was determined to be $3.22/MWh for DEC and $6.70/MWh for DEP. Tr. vol. 4, 78-80.

Witness Wheeler stated that the cap amount would be incorporated into Schedule PP to prescribe that "[i]n no event shall the integration services charge exceed [$0.00322 for DEC; $0.00670 for DEP] per kWh for Purchased Power Agreements executed under rates approved in Docket No. E-100, Sub 158." Tr. vol. 2, 229-30.

Section II of the SISC Stipulation provides that a solar generator that can demonstrate its capability of operating in a controlled manner that materially reduces or eliminates the need for additional ancillary service requirements (as reasonably determined by Duke) may reduce or eliminate the applicability of the integration services charge (Controlled Solar Generator). This capability could be demonstrated through inclusion of energy storage devices, agreeing to a dispatchable purchase contract, or other mechanisms that materially reduce or eliminate the intermittency of the output from the operating solar generator. Witness Wheeler clarified, however, that a solar QF seeking to eliminate the integration services charge must also contractually agree to operate its solar generating facility to meet operating requirements, as reasonably determined by Duke, that will actually reduce or eliminate the need for additional ancillary services. Witness Wheeler further testified that a QF committing to operate as a Controlled Solar Generator must enter into a negotiated PPA as QFs contracting to sell under Schedule PP are "must take" and may only be curtailed during system emergencies. Therefore, Schedule PP does not include the terms and conditions necessary for Duke and a solar generator to agree to operate as a Controlled Solar Generator. Tr. vol. 2, 229.

Witness Snider also testified that the SISC Stipulation's Controlled Solar Generator proposal reflects reasonable cost causation principles and allows an innovative solar QF not imposing incremental ancillary service requirements due to its operations to avoid paying the integration services charge. Witness Snider acknowledged NCSEA witness Beach's assertion that a solar generating facility that adds "significant storage" should be allowed to avoid the integration services charge and pointed out that the Controlled Solar Generator proposal provides an avenue to do that. Witness Snider, however, testified that even if a solar generating facility adds storage, it is critically important that the solar plus storage facility operate in a way that avoids incremental ancillary service requirements to avoid the integration services charge. Finally, witness Snider stated that without the operational control addressing how and when the solar generating facility is discharging output from its storage device, these facilities would likely just "shift" the time they discharge their batteries to premium pricing windows, which would not reduce the facilities' volatility nor avoid Duke's cost of providing additional ancillary services to address the solar generator's volatility. Tr. vol. 2, 147-58.

In its Initial Comments the Public Staff agrees that DEC and DEP face operational challenges due to the intermittent nature of solar resources and that intermittent and non-dispatchable resources have a direct impact on system operations, including cost. Public Staff Initial Comments at 34. The Public Staff also initially identifies certain concerns with the Astrapé Study's modeling approach, which were ultimately resolved as further described by Public Staff witness Thomas.

As Public Staff witness Thomas noted, in the 2016 Sub 148 Proceeding Public Staff witness Dustin Metz testified on the issue of integrating significant solar QF capacity, explaining that as installed solar QF capacity increases, Duke faces "increasing operational challenges as they seek to maintain the proper amount of contingency reserves that can be 'ramped up' and 'ramped down' in real time to meet resulting demand/supply imbalances." Tr. vol. 6, 357 (quoting 2016 Sub 148 Proceeding, tr. vol. 8, 117). Witness Thomas stated that integrating intermittent, non-dispatchable energy sources causes system operators to make decisions and deploy the fleet of utility-owned generation assets in ways that can increase costs to customers due to (1) thermal units operating outside their optimal output range, and (2) additional dispatchable units operating in standby mode, ready to respond within minutes to meet applicable NERC balancing requirements. Tr. vol. 6, 358.

Witness Thomas noted that the Public Staff identified technical concerns with the Astrapé Study in its Initial Comments, but that it later withdrew some of these concerns based upon additional discovery and ongoing technical discussions with Duke and Astrapé, and that it now supports Duke's integration services charge. Tr. vol. 6, 358-61. Further, witness Thomas stated that the Public Staff performed a review of seven integration studies from other utilities to compare methodologies and assess how the studies were conducted, including whether the utilities were modeled as load islands and what metrics were used to evaluate the system impact of intermittent resources. While every approach taken in the integration studies were different, the Public Staff's review indicates that Duke's proposed integration services charge is generally reasonable and within the other range of studies. In sum, witness Thomas testified that he believes that the methodology used to quantify the integration services charge is reasonable and that assessing this charge on solar QFs is appropriate. Tr. vol. 6, 361-67.

Witness Thomas testified that to address the Public Staff's concerns with Duke's proposal to update the charge biennially, Duke agreed to apply a cap on potential future increases of the integration services charge, as detailed in Section VI of the SISC Stipulation. Although as stated by Duke witness Wheeler, the inclusion of a cap might result in some level of subsidization of QFs, the Public Staff believes that it is important to ensure that the majority of costs imposed by intermittent solar QFs is recovered from intermittent solar QFs, and the cap provides a reasonable balance between reducing uncertainty for QFs and refunding ratepayers for the cost of integrating intermittent QFs. Tr. vol. 6, 368-72.

Regarding differing ancillary services costs for innovative QFs, witness Thomas testified that PURPA does not obligate the utility to purchase ancillary services from QFs. However, he agrees with NCSEA witness Johnson that QFs have the technical ability to provide ancillary services, and identified the Public Staff's interest in a potential future competitive solicitation for a limited quantity of ancillary services into which third-party generators could bid that has the potential to reduce costs to ratepayers and facilitate solar integration through cost-effective decisions. Witness Thomas also noted that there are several challenges to implementing a market for ancillary services in North Carolina, specifically that: (1) Duke is not a member of an RTO, and as such no organized competitive market for third-party services exists, (2) PURPA does not require utilities to purchase ancillary services from QFs, and because the responsibility for reliable grid operation falls on the utility, a market for such services would face significant regulatory challenges, and (3) the additional ancillary services needed, as identified by the Astrapé Study, is limited (192 MW); therefore, the costs to implement an ancillary services market might exceed the benefits. Witness Thomas stated that the Public Staff believes that innovative QFs installing technologies such as energy storage could reduce the need for ancillary services in a way that make imposition of the integration services charge on their facilities unnecessary. He stated that to the extent a QF can materially demonstrate that it does not impose additional ancillary service costs on the system, it should not be subject to the integration services charge. He concluded by explaining that Section II.A of the SISC Stipulation specifically grants a QF that enters into a negotiated contract the ability to mitigate the integration services charge by demonstrating and contractually obligating itself to operate in a manner that materially reduces or eliminates the need for additional ancillary services requirements. Tr. vol. 6, 376-81.

SACE's Initial Comments include a report by witness Kirby critiquing the Astrapé Study relied upon by Duke to quantify the integration services charge. Witness Kirby generally asserted that the Astrapé Study relied upon an inappropriate study methodology and contained errors in assumptions that resulted in the Astrapé Study overestimating Duke's operating reserve requirements and inflating solar integration cost projections. His primary critiques were that (1) the $LOLE_{FLEX}$ reliability metric is not related to mandatory NERC reliability requirements and is inappropriate for an integration cost analysis, (2) the production cost modeling assumption that DEC and DEP are "islanded" systems disconnected from the Eastern Interconnection is wrong, and (3) the linear scaling of expected short-term variability from new solar generators as solar penetration rises is physically incorrect.

Witness Kirby criticized the Astrapé Study's use of the $LOLE_{CAP}$ and $LOLE_{FLEX}$ metrics to identify instances of insufficient generation capacity or flexibility. He argued that the metrics were "misnamed" and "inappropriate" because there would be no loss of load expected during the identified imbalances for DEC or DEP Balancing Authorities (BA), which operate in the larger Eastern Interconnection. Interconnection, he stated, increases reliability while dramatically reducing individual BAs' balancing requirements. Consequently, Witness Kirby concluded that NERC reliability standards do not require the level of reserves or balancing operations necessary to meet the 0.1 $LOLE_{FLEX}$ for five-minute balancing that is the basis of the Astrapé Study. Tr. vol. 5, 178.

The Astrapé Study was modeled to require the DEC and DEP systems to meet a 0.1 $LOLE_{FLEX}$ requirement that allowed for a single five-minute imbalance every ten years. Although witness Kirby acknowledged that an LOLE of 0.1 is an appropriate and accepted standard for long-term planning of reserve capacity, he believes it was not required by NERC, "excessively expensive" when applied to actual operations, and inappropriate because a five-minute imbalance will not result in the need to shed firm load or a blackout. Witness Kirby argued that Astrapé subjectively used the $LOLE_{FLEX}$ standard and that it is not a generally used industry metric. Instead, according to witness Kirby, NERC determines operational reliability standards, and it does not require continuous perfect balancing from each BA. Witness Kirby elaborated that the applicable NERC reliability standard, BAL-001-2, Real Power Balancing Control Performance, establishes two reliability metrics that apply during normal operations: Control Performance Standard 1 (CPS1) and the Balancing Authority ACE Limit (BAAL). Tr. vol. 5, 178-82.

With respect to those metrics, witness Kirby noted in his testimony and in his Report that of the NERC requirements to which the Astrapé Study referred, CPS1 and CPS2, the CPS2 standard had been replaced in July 2016 with the BAAL requirement BAL-001-02. He characterized CPS2 as having a much more relaxed balancing requirement than the 0.1 $LOLE_{FLEX}$ requirement because CPS2 measured balancing over ten-minute intervals and required compliance only 90% of the time. According to witness Kirby, short-term, unexpected solar variability within the Duke service territories is unlikely to be related to frequency variations in the Eastern Interconnection. Therefore, CPS1 does not require correction of imbalances about half of the time, which significantly reduces the times Duke must exercise those reserves. In response to Duke's Reply Comments that described the $LOLE_{FLEX}$, he noted that NERC's CPS1 does not require perfect balancing for all but one five-minute interval in ten years; it instead limits annual average imbalances. Witness Kirby further contended that all imbalances are not bad. When interconnection frequency is below 60 Hz, over-generation helps to raise frequency and aids reliability; conversely, when interconnection frequency is above 60 Hz, under-generation helps lower frequency and aids reliability. Witness Kirby also offered that the NERC BAAL standard does not require perfect compliance. BAAL only limits ACE deviations that exceed 30 consecutive minutes and hurt interconnection frequency. He stated that ACE limits are lax when frequency is close to 60 Hz and get progressively tighter as the frequency deviates from 60 Hz. Therefore, witness Kirby concluded that the Astrapé Study used an unnecessarily stringent standard that resulted in an inflated integration services charge. Tr. vol. 5, 181-85.

Witness Kirby also disagreed with the Astrapé Study treating DEC and DEP as "islanded" power systems instead of modeling the interconnected BAs as part of the Eastern Interconnection. He argued that utilities interconnect because it gives all participants reliability and economic benefits. He doubted whether DEC or DEP would ever withdraw from the Eastern Interconnection because doing so would increase costs for ratepayers and reduce reliability. Therefore, he indicated that Astrapé should not have modeled DEC and DEP as islanded power systems. Witness Kirby instead argued that determining reserve requirements for islanded versions of DEC and DEP is not relevant to the way power systems are built and operated. In his opinion, the Astrapé Study failed to account for these reduced requirements and thus overstates the regulation requirements under which Duke operate. Tr. vol. 5, 185-89.

Witness Kirby also cited DEC's and DEP's participation in the VACAR Reserve Sharing Group, which he asserted enables them to significantly reduce the amount of contingency reserves they carry while still maintaining reliability. As members of a reserve sharing group, they can meet NERC standards and operate reliably with only a fraction of the contingency services required for islanded operations. Tr. vol. 5, 190-91.

Although witness Kirby acknowledged that the Astrapé Study had to model solar sites that do not yet exist and for which there is no data, he faulted the Astrapé Study's linear scaling of existing solar plant output data to represent new solar plants at higher penetrations. Witness Kirby testified that his review of the historic solar output of DEC and DEP showed an expected trend of short-term variability increasing more slowly than solar capacity as solar penetration increases. Thus, witness Kirby stated that the assumption of linear scaling is unjustified. He also faulted the Astrapé Study as using unrealistic geographic locations, leading to an increased short-term variability. Tr. vol. 5, 192-94.

Witness Kirby promoted the 2016 Idaho Power Integration Cost Study (Idaho Study) as a better model and methodological approach than the Astrapé Study because it employs production cost modeling with reserve requirements adjusted to maintain pre-solar-and-wind reliability levels and targeted reserves sufficient to compensate for 99% of the differences between the hour ahead average and actual five-minute deviations of solar output. He emphasized that the Idaho Study allows a cumulative 90 hours per year of deviations rather than one-event-in-ten-years, like the Astrapé Study relied upon by Duke. Witness Kirby further testified that the $LOLE_{FLEX}$ metric used in the Astrapé Study requires balancing that is over 10,000 times stricter than the 99% confidence level used in the Idaho Study. Witness Kirby disagreed with Duke witness Wintermantel that the Idaho Study's incremental load following reserves are comparable to the load following reserves required by the Astrapé Study. Instead, stated witness Kirby, while Idaho Power had higher rates of renewable penetration, DEC's and DEP's additional operating reserves far exceeded Idaho Power's as a function of renewable generation penetration. Tr. vol. 5, 200-05.

In its Initial Comments NCSEA states that the imposition of an integration services charge as proposed by Duke is inconsistent with previous Commission decisions in Sub 140 and Sub 148 because: (i) Duke did not include the benefits provided by QF generation in calculating the charge; and (ii) Duke developed a single standard offer rate schedule and separate "penalties" for intermittent QFs. NCSEA argues that the Commission had instead intended for the Utilities to propose multiple rate schedules based on the characteristics of the QF and not on the generation technology used by the QF. NCSEA Initial Comments at 32-35.

NCSEA also argues that Duke's request and DENC's similar request to implement a re-dispatch charge in this proceeding is improper as single-issue ratemaking. As such, NCSEA indicates that any integration services charge should be set during general rate cases. NCSEA agrees with Duke that 18 C.F.R. § 292.304(e) allows for the consideration of factors that may affect rates in determining avoided costs but notes that ancillary services are not listed among the factors and that charging intermittent QFs for ancillary services is not allowed. NCSEA Initial Comments at 47-49.

Moreover, NCSEA contends that the Astrapé Study is deficient in several ways. First, the Astrapé Study viewed DEC's and DEP's service territories as islands and not connected to neighboring grid systems. Citing to the Energy Imbalance Market (EIM) in the western United States, NCSEA argues that regional cooperation among utilities was a key factor in reducing integration costs and curtailment and had been successfully adopted in other parts of the United States. NCSEA Initial Comments at 36-42.

In his affidavit NCSEA witness Beach agrees with the concerns about the Astrapé Study expressed by SACE witness Kirby, and he also raises several other deficiencies. In addition to supporting the potential for increased solar penetration and integration cost savings through adoption of an EIM, witness Beach argued that the Astrapé Study appears to assume that future solar resources will be "must-take" with no flexibility in dispatching them and with no ability for the solar projects to provide ancillary services such as load following. Witness Beach indicates that utility-scale projects have demonstrated the capability to provide ancillary services, including upward regulation and load following. He also faults the Astrapé Study for not modeling the pairing of solar and storage projects. Witness Beach asserts that the use of storage will reduce substantially the variability of solar output and become a firm source capable of providing a variety of ancillary services. Beach Affidavit at 5.

Witness Beach additionally urges the Commission not to approve the integration services charge as proposed by Duke, arguing that the integration benefits of solar QFs outweigh the costs. He argues that Duke failed to analyze and quantify proposed avoided transmission and distribution capacity costs associated with integrating solar resources onto Duke's distribution systems.

Witness Beach suggests that QF generation can reduce peak loads on the utilities' transmission and distribution systems, allowing the Companies to avoided capacity-related transmission and distribution costs. Witness Beach also asserts that an offsetting adder or increase in avoided costs is appropriate to recognize that the integration of zero-variable cost output of wind and solar resources into wholesale power markets can suppress market prices, thereby benefiting utilities and customers. He also argues that the integration services charge should not be applied in any case when a solar project includes significant storage. *Id.* at 6, 19-21.

In its Reply Comments Duke addresses NCSEA's arguments that an integration services charge, in general, is inconsistent with PURPA and prior Commission decisions. Duke explains that FERC's implementing regulations expressly acknowledge that standard avoided cost rates may differentiate among QFs using various technologies based on their supply characteristics. Additionally, prior Commission orders acknowledge growing operational challenges due to non-dispatchable and intermittent resources, and specifically directed the Utilities to consider dispatchability, reliability, and other factors in determining avoided costs. Therefore, Duke responds that the consideration of increased ancillary service costs due to increased penetration of solar QFs through establishment of an integration services charge applicable only to solar generators reasonably and appropriately adheres to FERC's regulations implementing PURPA and the Commission's prior avoided cost orders. Duke also points out that other state commissions have similarly established wind- and solar-only integration charges as separate charges from avoided energy rates. Duke also rebuts NCSEA's argument that establishing the integration services charge in this proceeding violates the prohibition on single-issue ratemaking, explaining that while Duke agrees that general rates charged by a utility should be set in a general rate case proceeding, this standard is irrelevant in this case where the rates to be established are rates paid by the utilities to QFs under PURPA. Duke argues that establishing the integration services charge is well within the Commission's authority under N.C.G.S. § 62-156(b)(2) as part of the State's implementation of PURPA. Duke Reply Comments at 80-86.

In response to parties' technical concerns regarding the Astrapé Study, Duke reiterates in its Reply Comments that the proposed integration services charge is a conservative first step in incorporating the appropriate integration price signal for intermittent solar resources on Duke's system. Specific to parties' concerns over the Astrapé Study modeling DEC and DEP as islands, Duke explains that the Public Staff's and witness Kirby's assumptions that Duke can rely upon external market assistance from other BAs, VACAR Reserve Sharing Group members, or transfers of non-firm energy under Duke's Joint Dispatch Agreement to meet regulation reserve requirements on a real-time, intra-hour basis is incorrect. In response to NCSEA's critique that the Astrapé Study is flawed because intra-hour interchange of power could potentially be achieved through "regional cooperation" in the form of an EIM, Duke states that DEC and DEP are not market participants in an EIM, and that no such market construct exists across the entire Eastern Interconnect. Duke also notes that the Idaho Study, identified by SACE as a reasonably acceptable integration study, similarly does not assume that regional cooperation exists to manage intra-hour volatility, despite Idaho Power participating in the Western EIM. Additionally, Duke ran a sensitivity analysis to assume an unrealistic best-case scenario of full intra-hour coordination and sharing of load following reserves between the DEC and DEP BAs, which resulted in only a modest 15% decrease in the ancillary service cost impacts due to the resource sharing benefit being included in both the base (No Solar) and change (with solar) cases with the Astrapé Study model.

In explaining the Companies' actual system operations and presenting these additional sensitivity analyses, Duke supports analyzing DEC and DEP as islands for purposes of the model and illustrates that it would be unreasonable to assume that the Companies could rely upon one another or other BAs to provide the additional ancillary services required to respond to increased intermittent solar penetration in real-time. Duke Reply Comments at 86-94.

Regarding SACE's critique that the Astrapé Study used only one year of historic volatility data of the solar portfolio from October 2016 to September 2017 to quantify future volatility, Duke explains that the Astrapé Study attempted to address how to represent the aggregated volatility of the solar fleet as it increases in size on a forward-looking basis. Noting that SACE witness Kirby aptly characterized the Astrapé Study as "model[ing] solar sites that do not yet exist and for which there is no actual data," Duke states that the question for the modeler, then, is whether to assume available solar volatility data from operating solar facilities today is reasonably representative of the volatility that will occur at higher penetrations of solar projects to be installed in the future. Duke also highlights that the Public Staff's comments that "Astrapé self-identified the issues with solar volatility and fleet diversity within the report and made a fair conclusion," recognizes that future solar volatility is more uncertain at the significantly higher Plus 1,500 MW penetration level, and that it is difficult to project intra-hour solar volatility for these higher penetration levels without historical data. In other words, and as detailed in the Astrapé Study, it is a general principle of forward-looking modeling that the further out into the future that results are modeled, the more uncertain the results become; thus, Duke asserts that the Astrapé Study is not unreasonable in that its most forward-looking scenario analyzed is the most uncertain scenario produced in the Astrapé Study. Duke Reply Comments at 102-05.

In response to the Public Staff's concern regarding the Astrapé Study's use of historic vintage intra-hour volatility data for the period October 2016 to September 2017, Duke explains that the data used was the best and most current data available at the time. The Companies do not dispute, however, that use of more current solar volatility data can impact assumptions over time, especially as market conditions around the types of solar facilities being built in North Carolina evolve in the future. For this reason, Duke advocates updating the historic volatility data biennially in future avoided costs proceedings, just as it updates other aspects of its avoided costs to recognize changing resource mixes, load forecasts, and gas forecasts to ensure that the solar resource data is up to date and accurate. As discussed above, Duke and the Public Staff agreed in the SISC Stipulation to biennially review the integration services charge in future avoided costs proceedings and to cap increases in the integration services charge to mitigate this impact on QFs. Duke Reply Comments at 108-10.

As to the issue of applying the integration services charge on an incremental or average basis, Duke explains that applying the charge on an alternative "incremental" basis would unfairly burden new solar capacity with the full cost of ancillary services needed based on total solar capacity. Duke notes that no party challenged the average cost rate design or advocated that assigning the higher incremental ancillary services costs would be more appropriate. Concerning the Public Staff's comments on the integration service charge impacting market participants' costs in future CPRE RFPs, Duke contends that this is a risk faced by all business owners that can't control 100% of the factors impacting their business, and that it isn't unique to solar generators or CPRE participants. Solar generators do have an advantage over other business owners, however, as the rate cannot be adjusted without the full review and approval of the Commission. Duke's objective with introducing this rate is not to burden solar generation with new charges; instead, the integration services charge is intended to more accurately reflect the costs caused by the characteristics of solar generators on the system and to minimize potential future subsidization by ratepayers. Duke Reply Comments at 102-08.

As to SACE witness Kirby's comments stating that the Astrapé Study inappropriately models contingency reserve requirements, Duke states that his argument is flawed and that he incorrectly states that the SERVM model does not use contingency reserves where there is a loss of a generator or other reliability issues. Thus, Duke dismisses SACE's criticisms of the Astrapé Study, explaining that the criticisms were based upon an incorrect characterization of the $LOLE_{FLEX}$ metric used in the Astrapé Study. In support of the reasonableness of the Astrapé Study, Duke presents an analysis showing that the incremental operating reserves determined to be required by the Astrapé Study to integrate increasing penetrations of solar were reasonably comparable to the 2016 Idaho Study advocated for by SACE as a more appropriate and reasonable solar integration study to be utilized in North Carolina. Duke also notes that the Idaho Study suggests that the probability metric is "relatively immaterial" because the modeling objective of the Astrapé Study is to maintain the system at the same level of reliability both before and after solar is added to the system. In sum, Duke argues that the Public Staff's and other intervenors' technical concerns should be dismissed, and that the Astrapé Study reasonably and accurately calculated the solar integration costs applicable to QFs, resulting in a reasonable and appropriate solar integration charge of $1.10/MWh for DEC and $2.39/MWh for DEP. Duke Reply Comments at 93-110, 113-15.

In his rebuttal testimony Duke witness Snider emphasized that while SACE witness Kirby and NCSEA witness Beach continue to challenge certain technical aspects of the Astrapé Study, there is no dispute amongst the expert witnesses that the integration of uncontrolled, intermittent, and variable solar generators is causing Duke to incur increased ancillary services cost and that — absent an appropriate charge being established — such costs will continue to be recovered from customers. Tr. vol. 2, 136-37.

In response to NCSEA witness Beach's position that the Commission should recognize that future solar generators will be more controllable and that battery storage can reduce or eliminate integration costs, witness Snider testified that the Commission must not lose sight of the fact that any "benefit" to the grid is, in fact, limited to eliminating the intermittency and volatility caused by the solar QF generator's operations that are creating these incremental costs in the first place. To address the potential for solar generators to reduce or eliminate their increased ancillary services costs on the system, witness Snider stated that Duke and the Public Staff agreed in the SISC Stipulation to the Controlled Solar Generator option, which would allow innovative QFs to avoid these charges. Witness Snider also noted that future changes to the design and operational characteristics of the solar fleet actually installed in North Carolina can be addressed in future biennial reviews and updates to the integration services charge. Witness Snider also rejected Witness Beach's recommendation that the integration services charge should not be approved without recognizing purportedly offsetting "benefits" of integrating solar generation. Unlike the reduced line losses actually avoided by distribution-connected QFs, which Duke continues to recognize in quantifying avoided energy costs, the categories of costs identified by witness Beach are speculative and not real costs that will be avoided from QF purchases. Therefore, they do not offset the actually quantified increase in ancillary services costs caused by solar QF generators; accordingly, witness Beach's reasoning for opposing the integration services charge should be rejected. Tr. vol. 2, 139-41, 146-47.

Witness Snider further opposed NCSEA witness Beach's position that the Commission should consider an ancillary services market like the Western EIM to enable QFs to provide ancillary services. First, he stated that consideration of an EIM market is beyond the scope of this limited PURPA proceeding and is highly unlikely to occur before the next biennial avoided cost proceeding, when Duke propose to next review and update the integration services charge. In the interim, Duke will continue to incur increased ancillary services costs associated with integrating solar generators into the DEC and DEP systems; the integration services charge assures that the costs of these incremental ancillary services requirements are recovered from the solar generators who are the cost causers versus from retail customers. Witness Snider also questioned whether an ancillary services market enabling third party QF developers to make new investments to provide such ancillary services could provide the cost-savings benefit to customers advocated by NCSEA in light of the fact that the Duke-owned fleet has sufficient available capacity to meet the relatively limited additional ancillary services requirements (26 MW in DEC and 166 MW in DEP) identified as currently needed to manage the incremental volatility of QF solar resources. Establishing a new ancillary services market would not benefit customers as they would continue to pay for the Duke fleet as well as new resources procured through a market or competitive solicitation to provide the ancillary services. Witness Snider also highlighted that the Controlled Solar Generator provisions of the SISC Stipulation provides solar QFs pricing signals to evaluate the "market opportunity" to make incremental investments that could enable Duke to avoid incurring the increased ancillary services requirements caused by the uncontrolled volatility and intermittency of their operations. Tr. vol. 2, 142-45.

Witness Wintermantel highlighted in rebuttal testimony that collaboration between Duke, Astrapé, and the Public Staff had resolved each of the Public Staff's previous concerns, and that the Public Staff now supports the methodologies and assumptions underlying the Astrapé Study. He then responded to SACE witness Kirby's argument that the $LOLE_{FLEX}$ metric inappropriately requires the system to maintain enough ramping capability to match five-minute load ramps in all but one period every ten years, reiterating that SERVM models the DEC and DEP systems assuming perfect foresight for the next five-minute time step, meaning that net load is frozen and generators are allowed to catch up to load. Given this perfect foresight, the SERVM model should attempt to carry enough reserves to match the five-minute ramps in all but one period in ten years; however, in reality, operators never have perfect foresight, so many five-minute balancing deviations are expected to occur every year. If Astrapé had added reserves consistent with the largest five-minute unexpected solar deviation in ten years, more than 109 MW of load following reserves, and more than 354 MW of load following reserves, would have been required in the DEC and DEP Existing plus Transition cases, respectively, rather than the 26 MW and 166 MW identified by the SERVM model for DEC and DEP. Tr. vol. 4, 86-88.

Witness Wintermantel further stated that the SERVM model is not even capable of identifying the frequency of five-minute balancing deviations, and that the balancing requirements imposed by the NERC CPS1 and BAAL standards do not conflict with the 0.1 $LOLE_{FLEX}$ metric.

Thus, the 0.1 $LOLE_{FLEX}$ metric is not designed as a measure of a system's compliance with NERC CPS1 and BAAL standards. However, the NERC balancing standards and $LOLE_{FLEX}$ metric should correlate, meaning that if $LOLE_{FLEX}$ is allowed to increase substantially, it is expected that the NERC CPS1 and BAAL standards would be violated more often. To further rebut witness Kirby's arguments, witness Wintermantel explained that Astrapé performed additional calculations at the request of the Public Staff that demonstrated that if the flexibility reliability were measured at 1.0 events per ten years — i.e. the metric was "relaxed" to be "less stringent" by being increased ten-fold — the average ancillary service costs would only decrease from $1.10/MWh to $1.03/MWh for DEC and $2.39/MWh to $2.35/MWh for DEP, illustrating the relative immateriality of the reliability level. Therefore, testified witness Wintermantel, witness Kirby's objection to the subjective nature of the $LOLE_{FLEX}$ metric was overstated, and even the Idaho Study supported by witness Kirby similarly recognized that the selected reliability level is "relatively immaterial" in terms of quantifying integration cost because both the base case and change case are subject to the same metric. Further, witness Wintermantel explained that Astrapé compared the results of the Idaho Study to the Astrapé Study, and that the results were reasonably similar. Lastly, concerning the Idaho Study, witness Wintermantel stated that witness Kirby's alternative comparison of operating reserves based on a function of solar penetration is an inappropriate comparison and therefore should be ignored because the studies employ two different modeling approaches. Tr. vol. 4, 88-97.

Witness Wintermantel further testified that witness Kirby also incorrectly compared the need for load following reserves to one-minute net volatility because load following reserves are intended to cover volatility over longer five-minute time steps. He stated that witness Kirby incorrectly concluded that modeling DEC and DEP as islands precludes the consideration of the benefits of interconnected systems, explaining that doing so would imply that neighboring BAs would bear the costs of Duke's integration of solar resources. He further stated that the SERVM model implicitly recognizes the benefits of participating in an interconnected system by modeling reserves in the no-solar case that are comparable to historical reserves. Moreover, solar integration studies in other jurisdictions also do not assume that more frequent and larger magnitude balancing deviations should be absorbed through interconnections. In response to witness Kirby's concerns that an automatic generation control (AGC) tuning effort undertaken by Duke's system operations staff conflicts with the assumptions made in the Astrapé Study, he explained that there is no conflict because the Astrapé Study does not penalize solar for one-minute movements because it is conducted on a five-minute basis with perfect foresight, citing witness Kirby's own statements explaining that it is infeasible to actually model NERC BAAL standards in real time. Lastly, witness Wintermantel testified that witness Kirby's formula related to intra-hour volatility lacks empirical evidence, and contended that given the uncertainty in an actual diversity benefit of solar resources, it is more appropriate to rely upon actual historical data to set ancillary services cost rates at the time of the study and to perform updates of the study every two years so that the data used is the most accurate. Tr. vol. 4, 97-103.

Witness Wintermantel further disagreed with NCSEA witness Beach's statements that "there is no evidence that the high penetration of wind and solar resources that the CAISO system has integrated in recent years has increased ancillary service cost," citing to CAISO's 2016 Annual Market Performance Report stating that ancillary service costs had nearly doubled from 2015. Witness Wintermantel additionally rebutted NCSEA witness Johnson's claims that Astrapé by modeling one site per grid zone potentially misses diversity across the fleet, explaining that the number of sites modeled would not have a significant impact because Astrapé was concerned with the intra-hour diversity that would not be captured in the hourly solar profiles developed with NREL data. In conclusion, witness Wintermantel disagreed with Witness Johnson's arguments that Astrapé inappropriately failed to consider possible configurations which might alleviate some volatility, explaining that solar developers were not massaging their configurations to favorably affect the integration costs of solar at this time. Tr. vol. 4, 103-07.

Duke witness Wheeler testified in opposition to arguments by SACE witness Kirby and NCSEA witness Beach that the cap on the integration services charge agreed to in the SISC Stipulation should be set at the average projected integration cost versus the higher incremental level of costs, as agreed to by the Duke and the Public Staff. Witness Wheeler explained that it is important to first recognize that Duke and the Public Staff are not recommending that the monthly integration services charge rate be set at the higher "incremental" or marginal cost level because the cost is caused by all uncontrolled intermittent generators and will eventually be paid by all intermittent generators as the rate is phased-in with newly executed PPAs. However, the potential cost risk to customers during the biennial period as new intermittent generation is added up to the point in time when Duke's ancillary services costs are again reviewed in the next biennial proceeding is equivalent to the marginal or "incremental" ancillary services cost associated with this added generation. He argued therefore that the integration services charge rate design fairly balances generator and ratepayer interests by collecting an average cost rate, while recognizing the actual cost impact of the new intermittent generator on system costs by using a marginal cost rate cap. Tr. vol. 2, 240-41.

Witnesses for the intervenors also challenged the Astrapé Study on the basis that the study was not peer reviewed by a third party. In response, Duke witness Snider asserted that the Astrapé study was made available to the Public Staff and intervenors in November 2018, providing 8 months' opportunity to review, and that the Public Staff ultimately found the study results to be reasonable. Witness Snider also claimed that based on his ten years of testimonial experience, the Astrapé Study received "more attention than any other study" he could remember in recent history. Further, witness Snider noted that engaging third parties such as the intervenors in this proceeding in a peer review process would not be independent as these parties would have a specific objective to minimize or eliminate the integration services charge. Duke witness Wintermantel also testified that the technical studies that his consulting firm conducts for utilities and state public utility commissions typically are not circulated to additional academic firms for validation. Finally, Public Staff witness Thomas testified that to the extent the Commission is inclined to require a technical review group similar in structure to the one utilized in the Idaho Study, its emphasis should be on including technical experts and academics, and it would not be appropriate to include renewable energy developers or their advocates in the process. He concluded, however, that after a "thorough review of the Astrapé study and its results," the Public Staff found that the charge was reasonably calculated and that it was appropriate to assess that charge at this time. Tr. vol. 3, 11-14; tr. vol. 4, 204-05; tr. vol. 6, 433; tr. vol. 7, 105.

In response to questions from NCSEA, Duke witness Wheeler testified that Duke's intent was for the integration services charge to apply to Tranche 2 of the CPRE Program; however, the Duke witnesses were unaware of whether the integration services charge would be applied to solar generators contracting to deliver power under the Green Source Advantage Program. Public Staff witness Thomas stated that the charge would be considered for an uncontrolled solar generator participating in the CPRE and GSA programs, but noted that there were complexities in implementing the integration services charge under the CPRE program and that the charge had not been previously discussed in the GSA proceeding. Tr. vol. 2, 290-91; tr. vol. 7, 131-35; *see also* tr. vol. 2, 350-51.

Discussion and Conclusions

PURPA directs the FERC to adopt rules that require electric utilities to offer to purchase electric energy from QFs at rates that (1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and (2) shall not discriminate against QFs. Further, the statute provides that no such rule adopted by the FERC shall provide for a rate which exceeds the incremental cost to the electric utility of alternative energy. 16 U.S.C. § 824a-3(b). "Incremental cost of alternative energy" means the cost to the electric utility of the electric energy, which, but for the purchase from the QF, such utility would generate or purchase from another source. 16 U.S.C. § 824a-3(d).

The FERC adopted 18 C.F.R. § 292.101, *et. seq.*, to implement these directives, and nothing in these rules requires any electric utility to pay a QF more than the utility's avoided costs, or "the incremental costs to an electric utility of the electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(6).

Additionally, pursuant to N.C.G.S. § 62-156 the Commission is directed to determine standard avoided cost rates for each electric public utility according to standards set forth in N.C.G.S. § 62-156(b) with respect to rates paid for energy and for capacity purchased from small power producers. With respect to the rates that a utility pays for energy, N.C.G.S. § 62-156(b)(2) provides that such rates "shall not exceed . . . the incremental cost to the electric public utility which, but for the purchase from a small power producer, the utility would generate or purchase from another source." With respect to the rates that a utility pays for capacity, N.C.G.S. § 62-156(b)(3) provides that such rates "shall be established with consideration of the reliability and availability of the power."

In the Sub 140 Phase One Order the Commission stated:

> The Commission agrees that integration of solar resources into a utility's generation mix results in both costs and benefits, many of which may be appropriate for inclusion in a utility's avoided cost calculations. The avoided costs associated with the energy and capacity produced by QFs have already been discussed and are generally applicable to all QFs. Solar QFs, however, may require the consideration of additional factors, such as the potential for avoided and deferred capacity costs for transmission and distribution systems, avoided transmission and distribution line losses, ancillary services and grid support. The Commission is aware that several studies regarding, and methods to calculate these costs and benefits, are currently under development. . . . In light of these developments and the potential

> for significant amounts of solar generation to be constructed in North Carolina in the next few years, the Commission determines that It is premature for DEC, DEP and DENC to include integration costs and benefits associated with increasing levels of solar integration in their service territories in the calculation of their avoided cost rates.

Sub 140 Phase One Order at 60.

In that proceeding Duke presented a study conducted by Pacific Northwest National Laboratory (PNNL Study) that analyzed the operational impacts to the DEC and DEP systems as installed solar generation continued to increase. Duke proposed that "integration costs" associated with the increased reserve requirements identified in the PNNL Study that result from the increase in net load variability due to solar penetration should be taken into account in calculating Duke's avoided energy cost rates. Sub 140 Phase One Order at 57. The Commission determined that no comprehensive evaluation of solar integration costs in North Carolina had yet been undertaken and concluded that it was premature to apply any selected findings that could be derived from the PNNL Study:

> The Commission finds that, while ultimately it may be appropriate for DEC, DEP and DENC to include the costs and benefits related to solar integration in their avoided cost calculations, such inclusion will be appropriate only when both the costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained. Accordingly, the Commission concludes that it is premature for DEC, DEP and DENC to include integration costs and benefits associated with increasing levels of solar integration in their service territories in the calculation of their avoided cost rates.

Sub 140 Phase One Order at 61. The Commission found, however, that it would be "appropriate for the costs and benefits attributed to solar integration as such integration becomes more pervasive to be more fully evaluated in detailed integration studies." *Id.* at 8.

In the 2016 Sub 148 Proceeding the Commission determined that the pace and level of QF development continuing unabated posed serious risks of overpayment by utility ratepayers and raised concerns as to the operational soundness of the Utilities' electric systems. 2016 Sub 148 Order at 15. The Commission also recognized that North Carolina was at a "critical crossroads regarding the integration, development, and customer costs of renewable generation, and specifically with regard to QFs powered by solar energy," noting that installed solar QFs on the combined Duke systems had rapidly increased from 125 MW in 2012 to 1,600 MW in 2016. *Id.* at 15-16. Recognizing the economic and regulatory circumstances facing QFs, Utilities, and ratepayers in 2016, the Commission approved a number of modifications to North Carolina's avoided cost framework. The 2016 Sub 148 Order directed the Utilities in this 2018 proceeding to propose schedules specific to QFs that provide intermittent, non-dispatchable power if the Utilities' cost data "demonstrates marked differences" in the value of the energy and capacity provided by these QFs. 2016 Sub 148 Order at 98. In the 2018 Scheduling Order, the Commission again directed the Utilities to consider factors relevant to the characteristics of QF-supplied power — specifically intermittent and non-dispatchable power — in designing rates to meet

PURPA's objectives of appropriately valuing Duke's incremental costs of alternative energy to be avoided from purchasing QF power.

Duke proposes the integration services charge in response to these directives in an effort to recognize integration costs that Duke is incurring and to appropriately value the energy and capacity provided by QFs eligible for Schedule PP. The integration services charge reflects the impact on operating reserves, or generation ancillary requirements, as increasing levels of variable and non-dispatchable solar capacity continue to be installed on the DEC and DEP systems. Duke notes that installed utility-scale QF solar capacity in DEC and DEP has continued to increase from 1,600 MW in 2016 to over 2,300 MW as of September 30, 2018, including almost 1,800 MW of uncontrolled PURPA solar installed in DEP alone. JIS at 6.

As a threshold matter the Commission addresses NCCEBA and NCSEA's arguments that the proposed integration services charge is inconsistent with state and federal law. First, NCCEBA and NCSEA argue that the proposed charge is unlawful "single-issue ratemaking." In their view, avoided cost rates are within the term "rates" defined pursuant to N.C.G.S. § 62-3(24), and the Commission can only revise rates of a public utility in four contexts: (1) a general rate case held pursuant to N.C.G.S. § 62-133; (2) a proceeding pursuant to a specific, limited statute, such as N.C.G.S. § 62-133.2; (3) a complaint proceeding pursuant to N.C.G.S. § 62-136(a); or (4) a rulemaking proceeding. Because this biennial avoided cost proceeding is none of those proceedings, NCCEBA and NCSEA conclude that the Commission lacks authority to approve the proposed integration services charge. Further, they argue that "nothing in the statutory avoided cost mechanism contemplates" the proposed integration services charge or a decrement to avoided cost rates. Specifically, NCCEBA and NCSEA argue that N.C.G.S. § 62-156(b)(2) does not authorize a charge that captures a utility's costs that are caused by, rather than avoided by, the purchase of electric power from QFs. Duke and the Public Staff urge the Commission to reject this view.

After careful review of the plain text of the relevant statutes the Commission concludes that the term "rates" as defined in N.C.G.S. § 62-3(24) does not include the avoided cost rates established in the Commission's biennial proceedings held pursuant to N.C.G.S. § 62-156. As Duke argues, "rates" as defined in Chapter 62 applies to "every compensation, charge, [etc.] . . . *demanded, observed, charged or collected by* any public utility" for public utility service, N.C.G.S. § 62-3(24) (emphasis added), not to the avoided cost rates paid by electric public utilities. The provisions of N.C.G.S. § 62-156 support this conclusion by its use of the word "rates" with modifiers such as "rates...established as provided in subsection (b) or (c)," "the standard contract avoided cost rates," "rates paid by an electric public utility," and "rates to be paid by electric public utilities." It is a well-established principle of statutory construction that a section of statute dealing with a specific situation controls with respect to that situation, as against other sections of statute which are general in their application. *LexisNexis Risk Data Mgmt. v. N.C. Admin. Office of the Courts*, 368 N.C. 180, 187, 775 S.E.2d 651, 656 (2015) (citing *In re Testamentary Tr. of Charnock*, 358 N.C. 523, 529, 597 S.E.2d 706, 710 (2004) and *State ex rel. Utils. Comm'n. v. Lumbee River Elec. Membership Corp.*, 275 N.C. 250, 260, 166 S.E.2d 663, 670 (1969)). Therefore, the Commission concludes that the more specific statute, N.C.G.S. § 62-156, applies to the establishment of the avoided cost rates paid by electric public utilities in this and similar biennial proceedings, and not the sections of the Public Utilities Act that apply generally to the establishment or adjustment of rates any public utility may charge for public utility service. Accordingly, the Commission further concludes that the doctrine of "single-issue rate making" does not apply in this or similar proceedings, and the Commission will continue to establish avoided cost rates consistent with the provisions of N.C.G.S. § 62-156 and the FERC regulations implementing PURPA.

NCCEBA and NCSEA also argue that the integration services charge cannot be approved as proposed because the charge would be updated for a QF every two years during its contract as a result of the Commission's determination of the appropriate calculation in a biennial avoided cost proceeding. In support of their argument NCCEBA and NCSEA cite the 2016 Sub 148 Order, where the Commission determined that Duke's proposed two-year reset in the avoided energy component of the standard offer rate should not be adopted. The Commission finds the following discussion from that Order to be illuminating on the issue here:

> The Commission notes that a QF's legal right to long-term fixed rates under Section 210 of PURPA is addressed in FERC's *J.D. Wind* Orders. FERC's intention in Order No. 69 was to enable a QF to establish a fixed contract price for its energy and capacity at the outset of its obligation. . . . Further, in *Windham*, FERC reiterated Order No. 69 requires certainty with regard to return on investment and, thus, a legally enforceable obligation must be long enough to allow QFs reasonable opportunities to attract capital from potential investors. Subsequent FERC actions or inactions in allowing states to approve short-term fixed rates in standard offer PURPA PPAs must also be acknowledged in resolving the issues in this case.

2016 Sub 148 Order at 68-69 (citations omitted).

The Commission agrees with NCCEBA and NCSEA and affirms its view of the FERC's *J.D. Wind* Orders, Order No. 69, and *Windham*, as articulated in the 2016 Sub 148 Order for the purposes of this proceeding. Like the biennial adjustment in avoided energy rates that was at issue in the 2016 Sub 148 Proceeding, the proposed integration services charge that adjusts every two years "adds an additional element of uncertainty" to QFs' "ability to reasonably forecast their anticipated revenue, which may make obtaining financing more difficult than a longer term, fixed-rate PPA." 2016 Sub 148 Order at 68-69. Duke and the Public Staff base their support for the adjustment in the integration services charge on the goal of most accurately reflecting the ancillary services costs that Duke is incurring and ensuring that its customers are not unfairly subsidizing QFs. While a laudable goal, the Commission concludes that this is a goal that must yield to the PURPA mandate to provide QFs a reasonable opportunity to obtain financing, as that requirement is understood and has been applied by the Commission. Therefore, the Commission declines to adopt the proposed adjustment in the integration services charge and will require Duke to implement a fixed integration charge for the duration of the QF's contract and to provide sufficient data for Commission review of a similar charge for evaluation in future biennial avoided cost proceedings.

NCCEBA and NCSEA next argue that the proposed integration services charge cannot be approved as a "stand-alone charge" because a "third component of avoided cost" is inconsistent with FERC's regulations that require only the purchase of energy and capacity. The implication, in NCCEBA and NCSEA's view, is that any integration services charge deducted from the avoided cost rate would have to be calculated as part of either the avoided energy or avoided capacity rate. The Commission agrees with NCCEBA and NCSEA that the integration services charge proposed as a separate line item charge calls into question compliance with FERC's regulations requiring utilities to purchase energy and capacity from QFs.[1] Therefore, the Commission concludes that the reasonably known and quantifiable costs of integrating intermittent solar generation should not be approved as a separate line item charge for the purposes of this proceeding.

In their final legal objection NCCEBA and NCSEA argue that the integration services charge cannot be approved as a decrement to Duke's avoided energy rate because the charge is not a "rate" as defined in 18 C.F.R. § 292.101(b)(5), does not involve the sale or purchase of energy or capacity, and is not encompassed in the factors to be considered as affecting avoided cost rates pursuant to 18 C.F.R. § 292.304(e). Duke and the Public Staff argue that the Commission should take a broader view of these regulations. For the following reasons the Commission agrees with Duke and the Public Staff. First, the Commission agrees that the FERC's definition of "rate" applies to "*any* price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or *any* rule, regulation, or practice respecting any such rate, charge, or classification, and *any* contract pertaining to the sale or purchase of electric energy or capacity." 18 C.F.R. § 292.101(b)(5) (emphasis added). Significantly, this definition is not limited to prices, rates, or charges paid by an electric public utility nor is it limited to prices, rates, or charges received by an electric public utility. Conversely, "rate" is not limited to prices, rates, or charges received by a QF, nor to prices, rates, or charges paid by a QF. Instead, the Commission concludes that "rates" as defined in 18 C.F.R. § 292.101(b)(5) broadly encompasses all economic transactions between QFs and an electric public utility within the implementation of PURPA and the rules, regulations, practices, and contracts involved in such a transaction. Properly established, these rates must, as reasonably accurately as possible, approximate economic indifference between a utility's purchase of energy and capacity from a QF and supplying the equivalent energy and capacity from another source, including self-generation. 2016 Sub 148 Order at 17.

Similarly, the Commission concludes that NCCEBA and NCSEA's view of the factors affecting rates for purchase is too narrow. As provided in 18 C.F.R. § 292.304(e):

> In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:
>
> (1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;
>
> (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

[1] The Commission is not prepared to categorically agree that FERC's regulations prohibit the approval of any rate or charge other than those offered for energy and capacity. For example, the Commission has historically approved an "administrative charge" and a "monthly seller charge" in DEC's and DEP's respective standard offer schedule tariffs. No party has argued that this charge is unlawful as inconsistent with FERC's regulations, and the Commission does not so conclude here. In addition, if NCCEBA and NCSEA's prediction comes to pass that including the integration services charge as a decrement to the avoided energy rate is fraught with administrative and procedural hurdles, the Commission may consider revisiting this issue in the future.

(i) The ability of the utility to dispatch the qualifying facility;
(ii) The expected or demonstrated reliability of the qualifying facility;
(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities;

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

The provisions of this regulation not only allow but require the Commission to consider both the costs that the utility avoids by purchasing from a QF and the costs that the utility may incur, not otherwise accounted for, as a result of purchases from a QF. Consistent with 18 C.F.R. § 292.304(e), evidence of costs that a utility may incur because of purchases from a QF may be presented for review by the Commission (1) as part of the data provided pursuant to 18 C.F.R. § 292.302(b), (c), or (d); (2) in accounting for the factors listed in 18 C.F.R. § 292.304(e)(2); or (3) in taking into account the relationship of the availability of energy or capacity from QFs as derived in 18 C.F.R. § 292.304(e)(2) to the ability of the electric utility to avoid costs. This conclusion is consistent with the Commission's determination in the 2014 Sub 140 Order that it may be appropriate for the Utilities to include the costs and benefits related to solar integration in their avoided cost calculations when both the costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained. The Commission affirms that conclusion here. Therefore, the Commission proceeds to weigh the record evidence related to the reasonableness of the accuracy of the quantification of the integration services charge and its development as a component of Duke's avoided energy rates.

After careful consideration of such evidence and that no party otherwise contested or disputed such evidence, the Commission determines that DEC and DEP are incurring increased intra-hour ancillary services costs to integrate the "Existing plus Transition" level of solar QFs into the DEC and DEP systems. Therefore, for reasons discussed above it is appropriate to require

DEC and DEP to account for these costs when calculating the costs and benefits resulting from the purchase of energy and capacity from solar QFs.

In determining whether the quantification of Duke's ancillary services costs is reasonable, the Commission finds the testimony of Duke witness Wintermantel, including the Astrapé Study he sponsored as an exhibit, to be quite persuasive. The independent review conducted by the Public Staff, as described by witness Thomas, lends further credibility to Duke's evidence. Further, the agreements reached in the SISC Stipulation reflect the give-and-take in negotiations, and the Commission finds the testimony in support thereof to be quite persuasive. Finally, while NCSEA witness Beach and SACE witness Kirby have advanced reasonable and well-articulated criticisms of this evidence, the Commission determines that Duke and the Public Staff have adequately addressed these criticisms sufficient to rebut these arguments. In summary, the Commission gives weight to the testimony of witnesses Wintermantel and Thomas, and based upon a review of the foregoing evidence and the entire record herein finds that the results of the Astrapé Study that an additional 26 MW of load following reserves are required to integrate 840 MW of solar in DEC at an average cost of $1.10/MWh, and that an additional 166 MW of load following reserves are required to integrate 2,950 MW of solar in DEP at an average cost of $2.39/MWh are reasonable for use in this proceeding. The Commission further finds that it is appropriate for Duke to prospectively apply the integration services charge to all new uncontrolled solar generators that commit to sell and deliver power into the DEC and DEP systems on or after November 1, 2018, and to any pre-existing solar QF not subject to the integration services charge committing to sell to Duke under a new PPA in the future.

As stated above, however, the proposed adjustment in the integration services charge cannot be approved as it is inconsistent with FERC's regulations implementing PURPA. Although the Commission agrees with NCCEBA and NCSEA on the legal result, the Commission does not agree that the provisions of the SISC Stipulation, which the Commission otherwise has determined are lawful and supported by evidence of record, should be discarded. The evidence in this proceeding demonstrates that the increased ancillary services costs are sufficiently known and quantifiable to be impacting the value of QF-supplied energy and capacity, and the Commission has concluded here and in past avoided cost proceedings that such costs must be reflected in the avoided energy or avoided capacity rates established in this and similar proceedings. Therefore, based upon the foregoing and the entire record herein, the Commission finds that it is appropriate to apply the integration services charge as a fixed amount of $1.10/MWh for DEC and $2.39/MWh for DEP during the term of the contracts for those QFs that establish a LEO during the availability of the rates established in this proceeding, and this cost or charge should be included in each utility's avoided energy costs.

The Commission next determines that the agreement reached in the SISC Stipulation allowing "controlled solar generators" the opportunity to avoid the integration services charge through inclusion of energy storage devices, dispatchable contracts, or other mechanisms that materially reduce or eliminate the intermittency of the output from the solar generators should be approved. The Commission agrees with the Public Staff and NCSEA's in its Initial Comments that where certain QFs have the technical capability to reduce the additional ancillary services caused by the operation of uncontrolled solar QFs, such QFs should be able to avoid the integration services charge. Inclusion of this provision enables such innovative solar QFs to appropriately avoid the charge, reflects the give-and-take in negotiations between the Public Staff and Duke, and sufficiently responds to intervenors' recommendations.

Further, as Duke witness Snider testified, allowing such opportunity also reflects reasonable cost causation principles; to otherwise require a QF to pay for increased ancillary services that it is not causing would be unfair and create a disincentive for QFs to seek to avoid the charge. The Commission also agrees that having the ability to avoid the integration services charge may incentivize the deployment by QFs of battery storage and other technologies that can benefit Duke's system operators and customers through more coordinated dispatch and operational control of intermittent QFs, which, in turn, benefits customers by increasing system reliability and reducing costs. The Commission also finds persuasive that this may offer QFs the opportunity to adjust their production hours to maximize their financial benefit, which, in a time of declining natural gas prices, helps to further ensure the financial viability of North Carolina's renewable energy industry.

The record reflects that the Public Staff invested significant time in investigating the Astrapé Study through discovery, technical discussions with Duke and Astrapé personnel, and requests for further post-Study analyses and validation, as well as through a comparison of the Astrapé Study to other recent integration studies across the country. Tr. vol. 6, 409. The Commission appreciates the Public Staff's thorough investigation in this regard and finds highly persuasive Public Staff witness Thomas' testimony that the Public Staff's undertook review of seven integration studies from other utilities to compare methodologies and assess how the studies were conducted, including issues such as whether the utilities were modeled as load islands and what metrics were used to evaluate the system impact of intermittent resources. This testimony indicates that Duke's proposed integration services charge is generally reasonable and within the range of other studies.

Therefore, the Commission finds that it is not appropriate for DEC or DEP to impose the integration services charge on QFs that qualify as "controlled solar generators" by demonstrating that their facility is capable of operating, and by contractually agreeing to operate, in a manner that materially reduces or eliminates the need for additional ancillary service requirements incurred by the utility. In making this finding, the Commission has again placed weight on the evidence presented by Duke and the Public Staff. The Commission agrees with Duke and the Public Staff that it is appropriate to allow "controlled solar generators" the opportunity to avoid the integration services charge. The Commission also agrees with NCCEBA and NCSEA that such a provision should be submitted for Commission review and approval, and therefore finds that is appropriate to require DEC and DEP to file with the Commission proposed guidelines for QFs to become "controlled solar generators" and thereby avoid the integration services charge.[1]

The Commission also finds merit in the Public Staff's recommendation that Duke should be required to continue to evaluate the potential benefits provided by QF resources, particularly as new technologies such as energy storage and smart inverters are incorporated into QF projects in

[1] Subsequent to issuance of the Supplemental Notice of Decision, as required by Ordering Paragraph No. 4 of that order, on November 18, 2019, Duke filed for approval its Requirements for Avoidance of SISC. The Commission will issue an order shortly in this docket allowing parties to comment on Duke's proposal.

North Carolina, as well as those existing technologies such as small hydroelectric QFs that may have dispatch capability. Therefore, the Commission will direct Duke to provide the Commission, in its initial filing made in the 2020 biennial avoided cost proceeding, with an evaluation of whether a QF that can sufficiently demonstrate and contractually obligates itself to operate in a manner that not only eliminates the need for additional ancillary service requirements, but also has the capability to provide those benefits at a lower cost than the utility's own conventional resources, should be appropriately compensated for those benefits.

In conclusion, the Commission approves of certain provisions of the SISC Stipulation and Duke's integration services charge to be applicable to all non-controlled solar generators that either have committed to sell or prospectively commit to sell to Duke under Schedule PP or negotiated avoided cost rates on or after November 1, 2018, until the date that Duke next files avoided cost rates for Commission review in the next biennial avoided cost proceeding. Consistent with the agreement reached between Duke and the Public Staff in the SISC Stipulation, the Commission will review and update Duke's average and incremental ancillary services costs in the next biennial avoided cost proceeding to accurately reflect changes to DEC's and DEP's ancillary services costs as incremental solar is installed on the DEC and DEP systems; however, for reasons discussed herein, the charge will be fixed for the duration of the contract, as appropriate, for QFs establishing a LEO during the availability of the avoided cost rates established in each biennial proceeding. The Commission further finds that it is appropriate to require DEC and DEP to calculate avoided energy rates that do not include an integration services charge and to include these rates that would be available to "controlled solar generators" as a part of the tariffs and standard contracts in this proceeding.

Finally, the Astrapé Study methodology used to quantify DEC and DEP's increased ancillary services costs and to calculate each utility's integration services charge presents novel and complex issues that warrant further consideration. Therefore, the Commission agrees with NCCEBA, NCSEA, and SACE that the Commission would benefit from the results of an independent technical review of the Astrapé Study to inform future biennial avoided cost proceedings where similar issues will be reviewed. Therefore, the Commission directs Duke to assemble a technical review committee to provide a review of the Astrapé Study. The technical review committee shall be comprised of individuals, not otherwise affiliated with Duke or any of its affiliates or organizations in which Duke is a member, who have technical expertise, knowledge, and experience related to the integration of solar generation as well as the development of complex research, development, and modeling. The committee should include personnel employed by the National Laboratories with relevant experience and expertise. The purpose of the work with a technical review committee is to provide an in-depth review of the study methodology and the model used for system simulations. The technical review committee should provide specific comments or feedback to Duke in the form of a report, which report is to be included in the initial filing made in Duke's 2020 biennial avoided cost proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 43 AND 44

The evidence supporting these findings of fact is found in DENC's verified Initial Statement and in the testimony of DENC witness Petrie, Public Staff witness Thomas, and NCSEA witness Johnson.

Summary of the Evidence

In the 2016 Sub 148 Order the Commission determined that "avoided capacity calculations could send better price signals to incentivize QFs to better match the generation needs of utilities," and required the Utilities to consider refinements to the avoided capacity calculation and to address these refinements in this proceeding. 2016 Sub 148 Order at 56. The Commission directed the Utilities to consider "a rate scheme that pays higher capacity payments during fewer peak-period hours to QFs that provide intermittent, non-dispatchable power, based on each utility's costs during the critical peak demand periods." *Id.* The 2018 Scheduling Order similarly directed the Utilities to "file proposed rate schedules that reflect each utility's highest production cost hours, as well as summer and non-summer peak periods, with more granularity than the current Option A and Option B rate schedules." 2018 Scheduling Order at 1-2.

In response to the Commission's directives DENC in its Initial Statement proposes changes to the rate schedules for both energy and capacity that offer additional granularity and improved price signals to QFs to better match DENC's generation needs. DENC proposes a revised rate structure that includes seasonal capacity rates and non-seasonal on- and off-peak energy rates. DENC Initial Statement at 29.

With regard to capacity rates, DENC bases its proposed capacity peak hours on the hours when system peak loads historically have occurred, and when system emergencies are most likely to occur. DENC proposes to allocate capacity costs 50% to the summer season, 40% to the winter season, and 10% to the shoulder season, maintaining a slightly higher cost allocation to the summer months due to the Company's participation in PJM, which is a summer peaking system. *Id.* at 30-31.

Consistent with its comments regarding Duke's proposed rate design changes, the Public Staff in its Initial Comments states that the pricing periods proposed in this proceeding are an improvement over the current Option B hours in terms of being reflective of historical marginal energy costs. Nevertheless, the Public Staff believes that energy rate mismatches are still likely that could result in QFs potentially being over- or under-paid for the energy generated. Public Staff Initial Comments at 47–48. As a result, the Public Staff proposes its own seasonal energy rates and hours.

Regarding DENC's proposed seasonal allocation of capacity payment costs and its selection of Capacity Peak Hours, the Public Staff finds them to be reasonable, but states that the reliance on the broader characteristics of the PJM region results in a misalignment of DENC's system with the seasonal allocation and Capacity Peak Hour, and recommends that DENC evaluate alternative seasonal allocation and Capacity Payment Hours that align more directly to its system (as opposed to the PJM system as a whole, which has different capacity needs from a utility operating in North Carolina). *Id.* at 60, 64.

NCSEA states that the Utilities do not adequately recognize how costs vary across different times of day. NCSEA proposes that instead of the Utilities' proposals, the Commission should adopt its proposed time-of-day periods, as well as an optional, real-time pricing tariff for QFs. NCSEA Initial Comments at 28.

In its Reply Comments, DENC responds to NCSEA's proposal to incorporate geographic price signals that provide an economic incentive for QFs to locate in areas that are most advantageous to the grid by noting that a QF may choose to sell its power under the Schedule 19-LMP tariff that is locational in nature and has hourly granularity in its market-based prices. DENC Reply Comments at 25.

DENC further states that it continues to believe that its original proposed energy seasons and peak hours designations are reasonable and appropriate, particularly for the purposes of the standard offer. It also states that in subsequent discussions with the Public Staff on this issue, the Public Staff has recognized that September is appropriately included in DENC's summer peak season. In addition, DENC notes that in those discussions the Public Staff has proposed expanding the "premium peak" summer and winter hours such that there are four premium peak summer hours in the afternoon and four premium peak winter hours, two in the morning and two in the evening. As a result of these discussions, DENC indicates that it is willing to accept the Public Staff's proposal, as modified, in the interest of achieving consensus on this issue. DENC notes that its initial proposal included the afternoon hours on weekdays and weekends in the Energy Peak Hours, but under the modified proposal, it will pay on-peak and premium peak avoided energy rates on weekdays only. *Id.* at 22-24. With regard to capacity, DENC states it is willing to use a 45/40/15 seasonal allocation of CT costs, which would continue to reflect DENC's participation in PJM and the recent strong winter peak loads, as well as the shift of May from summer to shoulder season for capacity. *Id.* at 37.

NCSEA witness Johnson testified in favor of real-time pricing during "extreme conditions." He acknowledged the Utilities' reply comments on this topic and agreed that the Utilities raised practical considerations that need to be considered, but asserted that those considerations do not justify rejection of his proposal. He further stated that DENC's LMP tariff is not as good a solution as NCSEA's proposal because of its linkages to volatile natural gas and other energy markets, and instead recommended that the Utilities submit proposed real-time pricing rates consistent with NCSEA's proposal at least six months before the next biennial proceeding. Tr. vol. 6, 231-36.

Public Staff witness Thomas testified that the Public Staff agrees with DENC's proposed rate design modifications. He further noted that while the rate design proposals for DENC and Duke agreed to by the Public Staff were nearly identical, the Public Staff supports continued consideration of the unique characteristics for each utility in rate design. At the hearing, witness Thomas confirmed that the Public Staff agrees in principal with the energy and capacity rate design presented in DENC witness Petrie's rebuttal testimony. Tr. vol. 6, 394; tr. vol. 7, 100.

DENC witness Petrie testified that NCSEA witness Johnson's proposal to implement real-time pricing "essentially asks for both long term fixed prices and short term variable prices," and would effectively result in "higher-of" pricing — that is, the higher of the known FP rates and the potentially volatile LMP rates for a certain number of hours during the year. Witness Petrie testified that DENC believes this type of hybrid pricing is not reasonable because it is unfair to customers both for the optionality benefits provided to QFs at the expense of customers, as well as for administrative complexity. Tr. vol. 5, 47-48.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission finds that the revised rate design changes proposed by DENC and agreed to by the Public Staff are responsive to the Commission's directives in the 2016 Sub 148 Order and the 2018 Scheduling Order by providing QFs with more granular price signals to incentivize QFs to better match DENC's generation needs. The Commission therefore will require DENC to file updated rate schedules consistent with the energy and capacity rate design described in DENC witness Petrie's rebuttal testimony.

With regard to NCSEA witness Johnson's recommendation that DENC provide a hybrid rate that includes some real-time pricing components, the Commission agrees that real-time pricing rates for QFs could better align the utilities' avoided cost rates to QF payments, but recognizes that such an option must be balanced with the Utilities' obligations under PURPA to provide a QF with the option to commit to deliver its power at the utility's avoided cost calculated either at the time of delivery or at the time the QF makes its legally enforceable commitment to deliver energy and capacity. The Commission notes that DENC continues to make available its Schedule 19-LMP rates for QFs, as well as offer standard, fixed rate contracts under Schedule 19-FP. The Commission finds that it is appropriate for DENC to continue to offer its Schedule 19-LMP as an alternative to avoided cost rates derived using the Peaker Methodology, with rates based upon market-clearing prices derived from the markets operated by PJM, subject to the same conditions as approved in the Commission's last biennial proceeding.

The Commission further finds that DENC's revised proposed seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons are appropriate for use in weighting capacity value between seasons, as these weightings continue to reflect DENC's participation in PJM and the recent strong winter peak loads, as well as the shift of May from summer to shoulder for capacity, and should be used in calculating DENC's avoided capacity rates in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 45

The evidence supporting this finding of fact is found DENC's verified Initial Statement and in the affidavit of NCSEA witness Beach.

Summary of the Evidence

DENC describes in its Initial Statement the methodology it used to calculate avoided energy costs under its proposed Schedule 19-FP. DENC states that it used the PROMOD production cost model to derive avoided energy costs for Schedule 19-FP, with those rates reflecting an adjustment to reflect the locational value of energy in DENC's North Carolina service area where QFs are located, plus a fuel hedging benefit and a re-dispatch charge. DENC Initial Statement at 7. DENC states that it used the PROMOD output results to calculate the levelized on-peak and off-peak long-term fixed energy rates under Schedule 19-FP. *Id.* at 8.

Regarding forward commodity prices, DENC states that consistent with past practice it developed its avoided energy costs using 18 months of forward market prices, 18 months of blended prices, and then ICF International prices exclusively starting in month 37 of the forecast period. DENC notes that the Commission found this approach to be reasonable in the 2016 Sub 148 Proceeding. *Id.* at 8-9.

DENC explains that consistent with the Commission's conclusions in the 2016 Sub 148 Order, it adjusted the avoided energy costs proposed in this proceeding to reflect the fact that LMPs in the North Carolina area of its service territory continue to be lower than the LMPs for the PJM DOM Zone. DENC provides updated data showing the continued disparity in LMPs, and states that it included the historical average congestion differentials for on- and off-peak periods in its calculation of proposed energy rates. *Id.* at 9-11.

DENC also notes that in the Sub 140 Phase One Order the Commission determined that it is appropriate to recognize hedging costs that are avoided as a result of energy purchases from QF generation. DENC explains that in the Sub 140 Phase Two Order the Commission required the Utilities to utilize the Black-Scholes Model, or a similar model, to determine the fuel price hedging value of renewable generation. Consistent with its proposal in the 2016 Sub 148 Proceeding, DENC proposes to continue to use the same Black-Scholes Option Pricing Model to determine fuel hedging benefits that was proposed by the Public Staff in the 2014 Sub 140 Proceeding, with a resulting fuel price hedging value of $0.30/MWh, which was assumed constant for all years of the Schedule 19-FP contract. *Id.* at 11.

In its Initial Comments the Public Staff confirms that DENC used the same method for calculating its avoided energy costs for Schedule 19-FP as it did in the 2016 Sub 148 Proceeding, and states that it reviewed DENC's PROMOD inputs and believes that the inputs into the model and the output data from the model are reasonable for the determination of DENC's avoided energy costs in this proceeding. Public Staff Initial Comments at 19. The Public Staff does not raise any concerns with DENC's forecasted natural gas prices, and states that DENC's calculation of the fuel hedge value is reasonable. *Id.* at 28.

In its Initial Comments NCSEA states that QFs displace natural gas-fired generation, decrease exposure to volatility in natural gas prices, and provide a long-term physical hedge for the term of the PPA. NCSEA contends that renewable generation provides a hedge not otherwise available in financial markets. NCSEA asserts that the Black-Scholes Model assumes displaced gas is re-priced at the prevailing market price five or ten times over a ten-year period, which does not provide as effective a hedge as the hedge actually provided by a 10-year PPA. NCSEA cites studies performed in 2013 for Xcel Energy's Public Service of Colorado, which arrived at a $6.60/MWh hedge benefit of distributed solar (Xcel Study) and to the 2015 Maine Public Utilities Commission's Distributed Solar Valuation Study (Maine Study). NCSEA uses the Maine Study's method to calculate a ten-year hedging benefit of renewable PPAs in North Carolina using NCSEA's proposed gas forecast, current U.S. Treasury yields as the risk-free investments, the Utilities' weighted average costs of capital, and a marginal heat rate of 7,250 Btu/kWh. With this method, NCSEA calculates an avoided fuel hedging cost of about $0.007/kWh. NCSEA Initial Comments at 21-23. In his affidavit, NCSEA witness Beach reiterates that renewable QF generation provides a long-term physical hedge to natural gas prices, and he argues that the natural gas hedging costs used in the avoided cost rates in the past are too low because they only represent the cost to fix gas prices for one or two years rather than the ten-year hedge provided by renewable QF PPAs. Witness Beach also supports the Maine Study's method to calculate hedging costs. Beach Affidavit at 4.

NCSEA asserts that a balanced fundamentals forecast should be based on (1) the ICF forecast utilized by DENC, and (2) the new 2019 forecast from EIA. In the alternative, NCSEA states that it "would not object to the use of DENC's similar forecast methodology" of 18 months of forwards transitioning to a fundamentals forecast beginning at 36 months for all of the Utilities. NCSEA Initial Comments at 19. In his affidavit, witness Beach expresses support for a forecasting approach similar to that of DENC, using forward market prices as the forecast for no more than the first two years and then transitioning to the average of a set of fundamental forecasts by year five and using fundamentals forecasts from several sources to avoid over-reliance on one approach. Beach Affidavit at 3-4.

In its Reply Comments SACE does not specifically critique DENC's calculated hedge value and acknowledges that the Black-Scholes Model is an industry-accepted methodology for calculating fuel hedging costs, but advocates that Utilities use a methodology such as that used in the Maine Study to the extent they are able. SACE Reply Comments at 4-5.

No party objected to DENC's continued application of the LMP adjustment to its avoided energy rates.

In its Reply Comments DENC states that the use of the ICF forecast to forecast energy prices in avoided cost proceedings has been accepted by the Commission since the 2012 Sub 136 Proceeding and that DENC believes the method remains appropriate. In particular, DENC notes that ICF forecasts are reputable and respected in the industry, and the EIA forecast recommended by NCSEA does not provide tailored forward pricing for the mid-Atlantic region in which DENC operates, as do the ICF forecasts. DENC Reply Comments at 4-5.

With regard to hedging, DENC details that use of the Black-Scholes Option Pricing Model to determine fuel hedging benefits was thoroughly reviewed and proposed by the Public Staff in the 2014 Sub 140 Proceeding. In response to NCSEA and witness Beach's recommendation that the value of hedging should be calculated based on the cost of executing hedges over the full ten-year PPA horizon, DENC references the Commission's finding in the Sub 140 Phase Two Order that hedging benefits should only be valued over the hedging terms actually used by the Utilities which, in DENC's case, is approximately 18 to 24 months in the future. DENC explains that the Xcel Study is inappropriate for use in this proceeding because the results are inflated as it looked 20 years into the future using relatively stale high gas prices. DENC further states that when the Xcel Study was conducted in 2013, the forecasted natural gas price for 2025 was approximately $7.50/MMBtu, while the current forecasted price for 2025 is $4.00/MMBtu. DENC also notes that it is not clear if the Xcel Study used the cost of call options to determine the hedge value, and that it appears instead to be a cash flow discounting exercise that does not accurately represent the value of reduced natural gas pricing volatility in the future. DENC notes that the Maine Study is similarly outdated, its authors note difficulties with the method and how it required "some simplifying assumptions," and it does not include the possibility of future downward movements in natural gas prices. The resulting hedge value would lead to unreasonably high energy rates paid to QFs. *Id.* at 6-8.

In its Reply Comments the Public Staff states that in the Sub 140 Phase One Order the Commission found that renewable generation provides fuel price hedging benefits and that these benefits should be valued over terms that are comparable to the Utilities' hedging terms. The Public Staff also notes that in compliance with the Commission's directive from that order, DENC included the avoided fuel hedging values in its avoided energy calculations. The Public Staff disagrees with witness Beach's recommendation that the benefit of the hedge should be calculated to approximate the hedge value over a ten-year term because the Utilities rely on hedge terms that are significantly shorter. The Public Staff states that the value of the hedge should be calculated over a term comparable to the Utilities' actual natural gas hedge contracts that can be avoided, as proposed by DENC. Public Staff Reply Comments at 8.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission finds that DENC's proposed avoided energy inputs are reasonable for the purposes of this proceeding. Therefore, the Commission concludes that these energy inputs should be approved. With respect to the fuel forecast DENC used in its modeling, the Commission agrees that DENC's method of using the ICF forecast to forecast energy prices in avoided cost proceedings, which the Commission has accepted since the 2012 Sub 136 Proceeding, continues to be appropriate. No party raised specific objections to DENC's approach, and the Commission declines to require DENC to adopt witness Beach's proposed method for the reasons discussed in DENC's Reply Comments.

With regard to hedging, in the Sub 140 Phase One Order the Commission concluded that there are hedging benefits associated with renewable generation, and that it is appropriate to recognize the hedging costs avoided due to energy purchases from QF generation in calculating avoided energy costs. Sub 140 Phase One Order at 8, 42. In the Sub 140 Phase Two Order the Commission found it appropriate that the Utilities should calculate these hedging benefits using the Black-Scholes Model or a similar method that values the added fuel price stability gained through each year of the term of the QF contract. Sub 140 Phase Two Order at 7, 30-31. Based on the record in this proceeding, the Commission finds that the Black-Scholes Model or a similar method continues to be appropriate to reflect hedging benefits in avoided cost rates. The Commission therefore concludes that DENC has appropriately calculated avoided hedging costs using the Black-Scholes Model, and accepts as reasonable and appropriate for this proceeding DENC's proposed hedging value of $0.30/MWh, which it assumed constant for all years of the Schedule 19-FP contract. The Commission declines to accept witness Beach's recommendation that the benefit of the hedge should be calculated to approximate the hedge value over a ten-year term. The Commission continues to find, as it did in the Sub 140 Phase Two Order, that hedging benefits should only be valued over the hedging terms actually used by the Utilities, and DENC relies on an 18- to 24-month hedge term. Because the Commission continues to find the Black-Scholes Model or a similar method to be reasonable for calculating hedge value, and for the reasons stated by DENC, the Commission concludes that the Xcel and Maine Studies are not appropriate for use in determining avoided hedging values for avoided cost rates in North Carolina.

Finally, based on the evidence presented by DENC updating the continued disparity in LMPs in its service territory, which no party contested here, the Commission finds that it continues to be appropriate for DENC to include the historical average congestion differentials for on- and off-peak periods in its calculation of proposed energy costs for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 46

The evidence supporting this finding of fact is contained in DENC's verified Initial Statement and in the testimony of DENC witness Petrie, Public Staff witness Thomas, NCSEA witnesses Beach and Johnson, and SACE witness Kirby.

Summary of the Evidence

In the 2016 Sub 148 Order the Commission concluded that "it is appropriate to require the Utilities to consider and propose additional rate schedules in the next avoided cost proceeding that are based upon a consideration of the characteristics of the power supplied by the QF and not the technology that the QF uses to generate electricity." 2016 Sub 148 Order at 98. The Commission directed that with their initial filings in this proceeding the Utilities address, among other issues, "consideration of a rate design that considers factors relevant to the characteristics of QF-supplied power that is intermittent and non-dispatchable." *Id.* at 110-11. The 2018 Scheduling Order reiterated that directive.

In its Initial Statement DENC notes that the addition of new QF generation can have an impact in two distinct areas: ancillary services and integration costs. DENC proposes to adjust the avoided energy cost payments to new QFs to reflect the increase in system supply costs, or re-dispatch costs, caused by these generators. DENC defines re-dispatch costs as the additional fuel and purchased energy costs incurred due to the unpredictability of events that occur during a typical power system operational day. DENC states that as more and more intermittent generation such as solar or wind is added to the grid, the level of uncertainty regarding re-dispatch costs increases due to the unpredictable output of these types of units caused by changes in cloud cover or changes in wind speed. DENC clarifies that it is not proposing to adjust avoided cost rates to specifically account for the potential costs or benefits related to changes in ancillary services requirements that occur due to increased levels of new QF generation on the system. DENC Initial Statement at 12-13.

To calculate the re-dispatch cost, DENC explains that in conjunction with the development of its 2018 IRP, it performed a simulation analysis to determine the cost impact on generation operations. It used hourly generation data from 26 solar sites currently interconnected to its system to develop generation profiles for these facilities. DENC performed the study at three levels of solar penetration to provide a range of results. It used the PLEXOS model to determine an overall system cost impact, which it calculated to be approximately \$1.78/MWh, and proposes to adjust avoided energy payments made to QFs under Schedule 19-FP by that amount. *Id.* at 13.

In its Initial Comments the Public Staff does not oppose the concept of a re-dispatch charge but makes a number of recommendations and raises certain concerns. First, the Public Staff argues that the avoided energy rate should not be reduced by separately calculated charges, and states that a consolidated charge would present difficulties for tracking costs of compliance with the Renewable Energy and Energy Efficiency Portfolio Standard (REPS). The Public Staff recommends that DENC collect and administer the re-dispatch costs separately from the avoided energy rate, similar to Duke's approach for the integration services charge. Second, while the Public Staff agrees that it is reasonable to calculate the re-dispatch charge using solar resource data, as solar is the dominant type of intermittent, non-dispatchable QF, it suggests that in the future DENC separately calculate the charge specific to each type of intermittent, non-dispatchable QF seeking to interconnect to its system. Public Staff Initial Comments at 30-32, 43-46.

As for its concerns, the Public Staff states that DENC's calculation of the charge, which reflects equal weighting of multiple cost categories and solar penetration scenarios, may not be reasonable. More generally, the Public Staff notes the Commission's conclusions in the Sub 140 Phase One Order that inclusion of costs and benefits related to solar integration in the Utilities' avoided cost calculations would be "appropriate only when both costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained." *Id.* at 32 (quoting Sub 140 Phase One Order at 60-61). The Public Staff acknowledges that some costs of QF energy and capacity are less discernable than others, and states that it may be appropriate for the Commission to consider evidence from other parties regarding what additional costs or benefits can be sufficiently known and verifiable such that they should be included in avoided cost rates. *Id.* at 32-33.

In its Initial Comments NCSEA asserts as it did with respect to Duke's integration services charge that the re-dispatch charge is inconsistent with previous Commission decisions and does not comply with PURPA. NCSEA points to the Commission's recognition in the Sub 140 Phase One Order that it may be appropriate to reflect the costs and benefits of integrating solar resources into the Utilities' avoided cost calculations. NCSEA Initial Comments at 32-33. NCSEA contends that DENC's proposed re-dispatch charge fails to comply with the 2016 Sub 148 Order because the charge does not take the form of a separate rate schedule. NCSEA also asserts that the proposal is inappropriately based on generation technology rather than QF characteristics, and that DENC admits such noncompliance in its Initial Statement. NCSEA also argues that the re-dispatch charge represents single-issue ratemaking because it is a "rate" under N.C.G.S. § 62-3(24) and should be set during a general rate case. NCSEA argues further that the charge is not a "rate" under 18 C.F.R. § 292.101(b)(5) because it does not involve the sale or purchase of electric energy or capacity, and that even if it is a rate under FERC rules it is not appropriate under 18 C.F.R. § 292.304(e). *Id.* at 34-35, 47-48. NCSEA also claims that the Utilities fail to accurately capture the effect that wind and solar resources have on market prices by reducing demand on regional markets for electricity and natural gas, thereby reducing market prices. *Id.* at 43-45.

In his affidavit NCSEA witness Johnson states that refining avoided cost rates to consider the costs and benefits associated with integrating solar resources is "not objectionable, per se," but takes issue with how the Utilities conducted their respective analyses. He claims, among other things, that the Utilities fail to take an unbiased approach, only consider negative impacts imposed by solar QFs, and ignore the geographic diversity of solar QFs that avoids T&D costs. With regard to DENC's re-dispatch charge, in contrast to NCSEA's own position he does not oppose the concept of a re-dispatch charge itself, acknowledging that "[i]t is reasonable to expect solar generation to increase re-dispatch costs somewhat, at least under some circumstances, because solar generation varies with cloud cover which cannot be forecast with perfect accuracy." Johnson Affidavit at 17-18. He asserts, however, that the proposed $1.78/MWh is too high because DENC (1) only partly considered the benefits of geographic diversity by only relying on 26 individual sites for its analysis, and (2) improperly weighted the average of multiple cost and solar penetration scenarios. He presents his own calculation of a re-dispatch charge of $0.69/MWh, based on removal of the PJM and generation-only cost categories of DENC's re-dispatch analysis and the 80-MW solar penetration scenario. *Id.* at 18-20.

In his affidavit NCSEA witness Beach similarly claims that the re-dispatch charge does not consider the benefits of integrating QF resources into the system. Witness Beach also asserts that appropriately located QFs will allow T&D costs to be avoided, citing an example using Duke's distribution substations to show how avoided T&D costs can be allocated to hours of the year using peak capacity allocation factors. Witness Beach also asserts a potential market suppression benefit of integrating QF power and recommends that the Commission direct the Utilities to study the ability of their T&D system to host distributed generation and storage resources. Beach Affidavit at 6-7.

In its Initial Comments SACE disagrees with DENC's methodology for determining the re-dispatch charge for several reasons, including using the 80-MW solar penetration level and averaging the results of the analysis. Based on these alleged flaws, SACE concludes that DENC fails to adequately support its re-dispatch charge and that the Commission therefore should reject it. SACE Initial Comments at 17-18.

In its Reply Comments DENC reiterates the basis for its re-dispatch proposal and states that applying the re-dispatch charge will help ensure that its customers pay for accurate avoided costs, since without the charge customers would overpay for QF output. DENC explains that in the analysis providing the basis for the proposed charge, it gave equal weight to each of the cost categories considered, which included all costs, PJM purchases/sales, pumped storage costs/revenues, and generator costs only. DENC states that it chose solar penetration levels of 80 MW, 2,000 MW, and 4,000 MW for the analysis, and describes the process it used to calculate the charge based on those levels. DENC Reply Comments at 8-11.

DENC states that while it proposes to apply the re-dispatch charge as a reduction to the avoided energy rate for purposes of administrative efficiency, if the Commission agrees with the Public Staff that it should be separated from the avoided energy rate, DENC could modify the administration of the charge to occur as a separate line item on a QF invoice. DENC also states that it is willing to evaluate the potential for calculating separate re-dispatch charges for other generation types in future cases. *Id.* at 9-10.

DENC states that it discussed its proposal with the Public Staff and addressed a number of the Public Staff's questions and concerns. DENC also states that in those discussions, the Public Staff recommended re-calculating the re-dispatch charge without considering an 80-MW solar penetration level and allocating 70% to the 2,000-MW scenario and 30% to the 4,000-MW scenario. DENC describes these points as representing the Public Staff's remaining concerns with the re-dispatch proposal. DENC states that it continues to believe that the approach it took in the simulation analysis with respect to cost category and solar penetration level selection and weighting to be reasonable and provides arguments in support of those aspects of its original approach to calculating the charge. DENC states that it believes it is appropriate to weight each category equally, as each plays a major role in the total re-dispatch cost related to distributed solar generation. DENC also explains the rationale for including each of the solar penetration levels and for weighting each level equally in the charge calculation. DENC concludes, however, that in the interest of reaching compromise on the issue and narrowing down the areas of dispute, it is willing to recalculate the re-dispatch charge for purposes of this proceeding with modified cost category and solar penetration scenario weightings, resulting in a re-dispatch charge of $0.78/MWh. *Id.* at 12-14.

In response to NCSEA, DENC first clarifies that its presentation of the re-dispatch proposal does not constitute an admission of noncompliance with the 2016 Sub 148 Order, but rather makes clear that the proposal is intended to quantify the added costs due to re-dispatching of units caused by the intermittency of solar QF output, and not to specifically account for potential costs or benefits related to changes in ancillary service requirements. DENC also states that in preparing the initial filing and developing the re-dispatch charge proposal, it carefully evaluated the Commission's directives in the 2016 Sub 148 Order. DENC acknowledges the Commission's directive for the Utilities to consider and propose additional rate schedules in the next avoided cost proceeding that are based upon a consideration of the characteristics of the power supplied by the QF and not the technology that the QF uses to generate electricity. DENC states that in developing its proposal DENC determined that it would be more efficient, and therefore benefit both the QF and DENC, to include the re-dispatch proposal in the existing rate schedule rather than to propose a separate rate schedule only for intermittent QFs. DENC states its belief that QF developers are generally sophisticated entities that can determine which parts of a standard avoided cost tariff apply to them. DENC also notes, however, that it will comply with any Commission determination that the re-dispatch charge and other aspects of the proposed standard tariffs applicable to intermittent QFs should be reflected in a separate rate schedule. *Id.* at 15-17.

DENC further explains that the charge was derived based on data associated with the intermittent, non-dispatchable QFs in its service area, all of which at this point in time are in fact solar QFs. DENC notes that while the proposed charge is actually "based upon a consideration of the characteristics of the power supplied by" these QFs (those characteristics being intermittency and unreliability), for purposes of North Carolina, where almost all intermittent non-dispatchable QF generation is solar, there is inevitably an overlap between the concepts of "generation technology" and "QF characteristics." DENC concludes that, practically, these terms present a distinction without a difference. DENC notes its willingness to evaluate the potential to calculate a re-dispatch charge for other types of intermittent, non-dispatchable QFs in a future proceeding. *Id.* at 17.

DENC also addresses NCSEA's contention that the re-dispatch charge is a "rate" under N.C.G.S. § 62-3(24) that should be set during general rate cases pursuant to N.C.G.S. § 62-133, and that it is not a "rate" under FERC rules implementing PURPA because it does not involve the sale or purchase of electric energy or capacity. As to the former, DENC shows that the re-dispatch charge is not a "rate" as that term is contemplated by Section 62-3(24), which contemplates charges for services or commodities offered by the utility to the public, as the charge is not so related, but instead reflects the impact to DENC's system of intermittent, non-dispatchable QFs from which

DENC is required by law to purchase energy. DENC notes that taken to its logical end NCSEA's argument would nullify N.C.G.S. § 62-156. As to the latter, DENC states that the charge is valid regardless of whether it qualifies as a "rate" under 18 C.F.R. § 202.101(b)(5) and explains that it is also consistent with the Section 202.304(e) because it properly considered the enumerated factors listed in the FERC regulations. *Id.* at 17-19.

In response to NCSEA's and witness Johnson's contentions regarding costs and benefits, DENC explains that due to their intermittent nature and concentration in its small North Carolina service territory, non-dispatchable QFs do not allow DENC to avoid T&D costs; due to the potential for additional line losses resulting from backfeeding, the opposite is more likely true. *Id.* at 19-21.

DENC further states that its willingness to recalculate the re-dispatch charge consistent with the Public Staff's recommendations should address SACE's concerns with the proposal. *Id.* at 21-22.

In its Reply Comments the Public Staff presents a summary of DENC's proposed charge and states that it is not convinced that DENC considered the appropriate cost and solar scenarios in its re-dispatch charge calculation. The Public Staff disagrees with the "no PJM," "no pumped storage," and "generator cost only" scenarios because those categories do not represent DENC's current operations. The Public Staff states that while these scenarios may be illustrative of the impact solar "might" have on system costs were DENC to leave PJM or decommission its Bath County pumped storage facility, they are not appropriate for use in specifying a charge to apply to non-dispatchable QFs today. The Public Staff notes that the higher re-dispatch charge associated with a "No PJM" scenario indicates the value of being able sell excess energy into the PJM market. The Public Staff also finds the 80-MW solar penetration scenario to be inappropriate because DENC already has several hundred megawatts of solar capacity installed — the 2,000 MW scenario is more likely in the future due to the higher probability that DENC's total system will realize this level of intermittent capacity, and the 4,000-MW scenario might be achieved in the more distant future due to Virginia's mandate of increased deployment of solar resources through the Grid Transformation and Security Act of 2018. To address these concerns, the Public Staff proposes that DENC give 100% weight to the "all costs" category and no weight to the other cost categories, and give 70% weight to the 2,000-MW solar penetration scenario, 30% weight to the 4,000-MW scenario, and none to the 80-MW scenario. The Public Staff also notes that the re-dispatch charge and Duke's proposed integration services charge may result in recovery of overlapping costs, and states that to the extent the Commission approves the broader application of these calculations in future proceedings, it is appropriate for the costs to be fully delineated to reduce any overlap. Public Staff Reply Comments at 20-23.

In its Reply Comments NCSEA agrees with SACE's position that DENC inappropriately averages costs associated with multiple solar penetration levels and combinations of assumptions, which results in an inflated charge. NCSEA also echoes some of the questions raised by the Public Staff in its Initial Comments. NCSEA states its opposition to any fixed charge that "allegedly" offsets costs to the grid due to intermittent QFs, reiterating its position that distributed generation, including solar, causes a net benefit to the grid and rate payers. NCSEA Reply Comments at 17-18.

In its Reply Comments SACE contends that the Utilities fail to analyze the potential benefits of solar integration, and therefore do not comply with the Commission's previous orders. SACE also agrees with NCSEA that QFs should be compensated for the full range of costs they allow the purchasing utility to avoid, including applicable T&D costs. SACE recognizes the Public Staff's concerns regarding an integration charge's potential impact on REPS and other programs' administration if the charge is embedded in the avoided cost rate, but ultimately supports DENC's approach of applying the re-dispatch charge, if approved, as a decrement rather than as a stand-alone charge. SACE suggests that the Commission could establish a procedure to remove any integration charge in the administration of the applicable REPS or other program to address this concern. SACE Reply Comments at 13-16.

In his direct testimony DENC witness Petrie stated that in the 2016 Sub 148 Order and the 2018 Scheduling Order the Commission found merit in the concept that evaluation of the Utilities' avoided costs should consider factors such as a QF's capacity, dispatchability and reliability, and the value of QF energy and capacity in establishing avoided cost rates. He clarified that DENC's proposal to adjust the avoided energy cost payments made to intermittent non-dispatchable QFs under Schedule 19-FP by $1.78/MWh applied to both standard offer QFs and larger QFs with negotiated PPAs. He also clarified that while the re-dispatch charge is complementary to Duke's proposed integratioo services charge, the charges are not the same, as DENC and Duke each analyzed a different aspect of the impact of resource intermittency on their respective systems. Tr. vol. 5, 15-18.

Witness Petrie noted that the Public Staff did not disagree with the re-dispatch charge in theory and responded to several of the Public Staff's concerns and recommendations consistent with DENC's Reply Comments. He testified that since the filing of initial comments, DENC and the Public Staff discussed the re-dispatch proposal, including how the generation portfolios were constructed, how the 85 PLEXOS model runs were used, and other issues raised by the Public Staff, which resolved most of the Public Staff's concerns. With respect to Public Staff's remaining concerns regarding the weighting of cost categories and selection of solar penetration weights, as it notes in its Reply Comments DENC is willing to re-calculate the re-dispatch charge with modified cost categories and solar penetration scenarios as recommended by the Public Staff, resulting in a $0.78/MWh re-dispatch charge. Tr. vol. 5, 19-22.

Witness Petrie responded to NCSEA's contention that the re-dispatch charge failed to comply with the 2016 Sub 148 Order. He stated that the re-dispatch charge is compliant with the 2016 Sub 148 Order's statement to "consider and propose additional rate schedules" because DENC did consider proposing new rate schedules, but determined that in the interest of efficiency, the re-dispatch charge should be included in the existing rate schedule. However, if the Commission determines that the re-dispatch charge and other aspects of the proposed standard tariffs applicable to intermittent QFs should be reflected in a separate rate schedule, DENC will comply with that determination. With respect to NCSEA's assertions regarding the focus on generation technology, he stated that the re-dispatch charge is based on data associated with the intermittent, non-dispatchable QFs in DENC's service area, all of which are solar QFs. Therefore, there is an inherent overlap between the concepts of "generation technology" and "QF characteristics," and for DENC's purposes those terms present a distinction without a difference. Tr. vol. 5, 22-24.

Witness Petrie stated that NCSEA and SACE's concerns regarding the actual derivation of the re-dispatch charge should be addressed by DENC's willingness to recalculate the charge as recommended by the Public Staff. He also responded that DENC did account for both costs and benefits associated with distributed solar generation in its re-dispatch analysis as well as in the basic avoided energy rate. He testified that the macro benefits to new solar generation, including zero fuel cost for solar generation, displacement of DENC owned generation, and PJM purchases during daytime hours, and the related fuel price hedge benefit were reflected in the production cost modeling and in the separate hedge value adder to the energy rates. He noted that DENC has not observed any benefits with respect to system dispatch and minute-to-minute operational control of the grid from the addition of intermittent resources, such as solar QFs, to its system that are not already accounted for in the avoided energy costs. Tr. vol. 5, 24-25.

Witness Petrie also responded to NCSEA witness Johnson's contentions regarding geographic diversity, explaining that the QFs evaluated for the re-dispatch analysis are in fact geographically dispersed throughout DENC's service area, including North Carolina. He stated further, however, that the North Carolina portion of that service area is relatively small, with very limited geographic diversity as compared to the rest of DENC's footprint. He noted that as a result, the intermittency of solar QFs located in North Carolina is not mitigated by their geographic diversity throughout DENC's service area. Witness Petrie also clarified that PJM market purchases and sales are accounted for in the re-dispatch study, as the PLEXOS model assumed DENC would sell excess power into PJM during the peak hours with higher LMP costs and make market purchased at low prices. In calculating the re-dispatch cost, DENC netted market purchases and sales against each other, which resulted in a net benefit to the solar re-dispatch cost. Tr. vol. 5, 25-26.

Witness Petrie concluded by noting that there are 72 solar QFs operating in DENC's North Carolina service area, representing approximately 501 MW of solar capacity. Once all of the QFs with which DENC has executed PPAs come online, that total will rise to 691 MW, which significantly exceeds DENC's 2018 average on-peak load of approximately 525 MW. He stated that DENC's proposed re-dispatch charge represents the first step in quantifying the costs of integrating these large volumes of solar generation onto its system, which was first addressed in the 2012 Sub 136 Proceeding. He stated that DENC will continue to work on this issue, but for purposes of this biennial period believes that the re-dispatch charge is fair to both QFs and DENC's retail electric customers because it will provide energy payments to QFs that better reflect DENC's actual avoided energy costs. *Id.* at 27-28.

In his testimony Public Staff witness Thomas described the re-dispatch charge as reflecting the deviations from the optimal dispatch order of DENC's fleet of dispatchable generation units due to fluctuations in the output of intermittent, non-dispatchable resources. He stated that similar to the changes in dispatch order caused by load certainty, the uncertainty of intermittent, non-dispatchable energy resources causes units to be dispatched out of least-cost dispatch order on an hour-to-hour basis, leading to increased fuel and purchased energy costs that are passed on to ratepayers. He also noted that unlike Duke's method of calculating the integration services charge, DENC's method of calculation does not measure system reliability. Tr. vol. 6, 373-74.

Witness Thomas testified that the re-dispatch charge is a reasonable attempt to quantify the costs incurred by intermittent generators but noted that the Public Staff identified potential concerns with the charge as proposed. He noted the Public Staff's suggestion of an alternate set of weightings resulting in a re-dispatch charge of $0.78/MWh, which the Public Staff believes better reflects the DENC system and actual costs incurred. He argued that including cost scenarios such as the "no PJM" scenario inappropriately excludes benefits provided by solar QFs due to DENC's membership in PJM. He acknowledged DENC's willingness to recalculate the charge with the Public Staff's recommended weightings. He recognized that the re-dispatch charge and Duke's integration services charge attempt to quantify different aspects of integrating intermittent generation and use different approaches but based on the Public Staff's review of these proposals stated that there is likely some overlap between them. *Id.* at 374-76.

In their comments filed in this proceeding, the Public Staff and NCSEA discuss whether or not solar QFs with battery storage capability should be subject to Duke's proposed integration services charge. The SISC Stipulation provides, in part, that certain QFs would be exempt the integration services charge if they can operate the facility in a manner that "materially reduces the need for additional ancillary service requirements," as determined by Duke, to include battery storage, dispatchable contracts, or other mechanisms. In his testimony, Public Staff witness Thomas testified that the Public Staff believes that certain technologies, such as energy storage, could if operated appropriately reduce or eliminate the intermittency of solar generator output, and recommended that to the extent a QF can materially demonstrate that it does not impose additional ancillary costs on the system, it should not be subject to the integration services charge or, "to a lesser extent," the re-dispatch charge. *Id.* at 376-81.

NCSEA witness Beach testified generally on the re-dispatch charge together with the Duke integration services charge. Witness Beach recommended that the Commission not adopt either of these proposed charges and asserted that any cost to integrate solar resources will be offset by benefits of these resources that he contended the Utilities have not recognized. Tr. vol. 5, 112.

In his testimony SACE witness Kirby asserted a lack of detail supporting the re-dispatch charge calculations; and he contended that DENC did not include an analysis of the benefits of solar projects. He also, however, testified that DENC's agreement to remove the 80-MW solar penetration scenario from its analysis and to solely use the "all costs" category for its re-dispatch charge analysis instead of averaging all four of its originally proposed cost categories helped alleviate his concerns on these fronts. Tr. vol. 5, 208-10.

In his rebuttal testimony, DENC witness Petrie testified that DENC remains willing to accept the Public Staff's recommended modifications to the re-dispatch charge calculation and resulting charge of $0.78/MWh for purposes of this proceeding. He noted that while NCSEA witness Beach generally recommends rejection of the re-dispatch charge, he does not offer any specific critiques of the charge itself. To the extent witness Beach's claims that the utilities did not properly consider and quantify the benefits of solar in presenting their proposed charges were made with respect to DENC, witness Petrie referenced his direct testimony and DENC's Reply Comments and testified that DENC has properly considered both costs and benefits in both the avoided cost rates and the re-dispatch charge. Tr. vol. 5, 37-40.

Witness Petrie also disagreed with any characterization of the charge as a "penalty." He stated that DENC's avoided energy costs are based on the difference in system production costs between a PROMOD model case without incremental QF energy deliveries and a case with a 100 MW flat block of zero-cost QF energy added to the system. He stated that because QFs do not deliver the same amount of energy every hour (i.e., they are intermittent and fuel limited), the rates derived from those model results should be adjusted to reflect the cost impact of the QF generation profile. He stated that the re-dispatch charge represents that adjustment, which improves the accuracy of the avoided energy rates and accounts for the way that the rates are calculated from the modeling results. With regard to SACE, witness Petrie reiterated that DENC did consider the benefits of solar facilities interconnected to its system but noted that DENC's willingness to recalculate the re-dispatch appeared to mitigate witness Kirby's concerns. Tr. vol. 5, 37-39.

Finally, witness Petrie addressed the Public Staff's suggestion that to the extent a QF can materially demonstrate that it does not impose additionally ancillary services costs on the system, it should not be subject to re-dispatch charge. He stated that although the addition of battery storage may potentially smooth the QF's output during certain hours, the shape of the energy output during the middle of the day, in between charging in the morning and discharging in the evening, will still exhibit a considerable amount of volatility, which the re-dispatch charge would account for. He noted that DENC has yet to study the actual effect of a battery on output, which would need to be calculated to determine any appropriate discount to the re-dispatch charge. He therefore argued that the recalculated $0.78/MWh charge should apply to all solar QFs in this biennial period and be updated as appropriate in future proceedings based on further modeling to analyze the impact of new solar QFs co-locating battery storage at their facilities. Tr. vol. 5, 40-42.

At the hearing, SACE witness Kirby recommended rejection of the re-dispatch charge until it is recalculated based on both the cost and benefits of integrating solar. DENC witness Petrie clarified in response to questions from counsel for SACE that in developing the re-dispatch charge, DENC focused only on re-dispatch costs and not ancillary services, and that he could not speak to whether Duke's integration services charge reflected some element of re-dispatch costs. He also clarified that DENC has no intention of double-counting re-dispatch costs, and that he expects DENC in the future to conduct a more comprehensive study that accounts for ancillary service costs. He also testified, and reiterated upon questioning by the Commission, that there are conceivable circumstances where it would be appropriate to not apply the re-dispatch charge to a QF that has installed battery storage. Witness Petrie also agreed in response to questions by counsel for the Public Staff that the re-dispatch charge could decline in the future. DENC witness Billingsley clarified in response to questions from SACE counsel that if approved the re-dispatch charge would apply prospectively only, including to QFs that renew their PPAs after the initial term has concluded. Tr. vol. 5, 80-82, 92-94, 100-03, 215.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, and for reasons similar to those discussed in other sections of this Order with respect to Duke's proposed integration services charge, the Commission finds that DENC's proposed re-dispatch charge, as modified to be $0.78/MWh, is reasonable for purposes of this proceeding.

As with Duke's proposed integration services charge, no party presented evidence to contradict that DENC is experiencing re-dispatch costs associated with the integration of intermittent, non-dispatchable QFs on its system. NCSEA witness Johnson specifically acknowledged that it is reasonable to expect solar generation to increase re-dispatch costs somewhat, at least under some circumstances, due to the variability of solar generation caused by cloud cover. With the exception of witness Johnson, NCSEA and SACE oppose the re-dispatch charge proposal, but do not present evidence to contradict it, particularly given DENC's agreement to recalculate the charge consistent with the Public Staff's recommendations. Given the evidence presented, the Commission concludes that the charge, modified as agreed to by DENC, should be accepted for purposes of this proceeding.

For reasons similar to those details above, the Commission concludes that the re-dispatch charge complies with PURPA and FERC's regulations implementing PURPA, N.C.G.S. § 62-156, and the Commission's orders issued in biennial avoided cost proceedings. As directed in the 2016 Sub 148 Order DENC has proposed an adjustment to its rates to account for the characteristics of intermittent, non-dispatchable QFs.

The Commission is not persuaded by the comments and testimony offered by NCSEA and SACE that DENC did not consider benefits as well as costs in developing the re-dispatch charge. The Commission finds DENC's filings and particularly witness Petrie's testimony highly persuasive on this point. DENC has already reflected certain benefits of solar, including hedging value, in the underlying avoided energy cost rate. Moreover, the re-dispatch charge does, as shown by DENC's testimony and other evidence presented, reflect benefits as well as costs. In contrast to intervenors who advocate for rejection of the re-dispatch charge, DENC provided data supporting the charge based on solar generation located on its own system. Evidence presented relating to the New England ISO, for example, is not relevant to this proceeding. For the reasons stated above, the Commission also declines to accept witness Beach's suggestion to direct the Utilities to study the ability of their T&D system to host distributed generation.

In addition, the Commission concludes that the re-dispatch charge complies with PURPA and FERC's regulations because the re-dispatch charge reasonably approximates utility indifference. With regard to DENC's approach to calculating the re-dispatch charge, the Commission concludes that the use of the re-dispatch analysis from the 2018 IRP was reasonable and appropriate. The analysis was based on actual historical data from solar facilities existing on DENC's system, which was analyzed over 85 model runs in various scenarios to develop the charge. In sum, the Commission finds that DENC has made a substantial and well-supported effort to comply with the Commission's directive, which is augmented by DENC's willingness to re-calculate the charge consistent with the Public Staff's recommendations. The resulting $0.78/MWh charge is close to the $0.69/MWh charge that witness Johnson calculated as an illustrative alternative. DENC has indicated that the charge represents its first step in quantifying the costs of integrating large volumes of solar PV generation onto its system, and that it will continue to evaluate these costs and benefits going forward. The calculation was made using the best information available at the time, but with further evaluation and refinements, as well as further changes in the development of QF projects, DENC acknowledges that it could decline in future proceedings. The Commission therefore agrees with witness Petrie that for purposes of this proceeding the re-dispatch charge is fair to both QFs and DENC's retail electric customers because it will provide payments to QFs that better reflect DENC's avoided costs.

The Commission recognizes the discussions regarding a potential overlap between the costs being borne by each utility that DENC's re-dispatch charge and Duke's integration services charge are intended to recover. In this proceeding, each utility has taken its own approach to evaluating and quantifying the costs to its system from intermittent, non-dispatchable QFs. Should DENC propose a revised charge or charges in the next biennial proceeding to address other costs to its system resulting from such QFs, the Commission will evaluate the reasonableness of such a charge at that time. Finally, DENC acknowledged that there could be circumstances where a QF, due for example to the addition of a battery, could justify an exception from the re-dispatch charge. As with Duke, the Commission finds it is appropriate to require DENC to file with the Commission a proposed protocol for avoidance of the re-dispatch charge.

In conclusion, the Commission finds that DENC's proposed re-dispatch charge of $0.78/MWh is reasonable for purposes of this proceeding. In the filing of rate schedules that it makes in compliance with this Order, DENC should reflect the modified re-dispatch charge of $0.78/MWh in its Schedule 19-FP, consistent with the decisions relevant to Duke's proposed integration services charge included in this Order, to the extent possible. In addition, the Commission will direct DENC to file a proposed protocol for avoidance of the re-dispatch charge similar to those protocols required from Duke.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 47

The evidence supporting this finding of fact is found in DENC's verified Initial Statement and in the affidavit of NCSEA witness Johnson.

Summary of the Evidence

In its Initial Statement DENC proposes to apply annual capacity payment caps that reflect the characteristics of intermittent non-dispatchable resources. DENC notes the 2016 Sub 148 Order directive that the Utilities only offer avoided capacity payments in years in which the utility's IRP shows a need for capacity and that the Utilities should propose schedules demonstrating any "marked differences in the value of the energy and capacity provided by these QFs." 2016 Sub 148 Order at 98. DENC states that because solar and wind generation is intermittent in nature, the capacity benefit of these resources is not equivalent to the capacity benefit of a conventional CT unit. DENC provides data supporting the lower capacity value offered by solar and wind QFs on its system. Specifically, DENC presents data showing the hourly system loads of the PJM DOM Zone on the peak day from the summer of 2018 overlaid with the aggregate output from DENC's solar contracts. This data demonstrates that even under favorable sun conditions on a hot summer day, these units could not deliver output at their full nameplate capacity during the hours when the power was needed most, showing that they do not fully displace the operation of dispatchable CT units. DENC also presents data showing the hourly system loads of the PJM DOM Zone on the peak day from the winter of 2017/18 overlaid with the aggregate output from DENC's solar contracts. This data demonstrates that on a peak day in winter the capacity value of the solar facilities was nearly zero, again showing that these resources do not displace CT generation at the time of winter morning and evening peaks. DENC Initial Statement at 20-21.

Based on this data, DENC proposes an annual payment cap reflecting the capacity value of intermittent QFs relative to fully dispatchable CT facilities. DENC clarifies that all QFs, regardless of technology, would continue to receive the same capacity rates, but the payments would be capped on an annual basis for QF resources at levels reflecting the operating characteristics and capacity value of these resources. DENC determined those levels by first calculating the levelized annual capacity value of a new CT, which it explains represents the maximum amount that a QF could receive for capacity if it generated at its rated capacity during all of the seasonal capacity on-peak hours, and which it based on 100% of the fixed costs of a new CT during the year that DENC has a capacity need. DENC then multiplied that benchmark capacity value of a fully dispatchable CT by percentage factors representing the capacity value relative to a CT for solar-tracking, solar-fixed tilt, and wind. These percentage factors — 23%, 16%, and 13%, respectively — were based on the average output from each of these types of resources during the critical peak winter and summer hours. The result is proposed capacity caps of $8.55, $5.95, and $4.83/kW per year for solar-tracking, solar-fixed tilt, and wind, respectively. DENC states that once an intermittent QF reaches the applicable limit for capacity payments on an annual basis, the cap would be triggered and the QF would receive no further capacity payments during that year of the contract term. Capacity payments would resume at the beginning of the next year of the contract term and continue through that contract year unless and until the point at which the annual cap is again reached. *Id.* at 22-24.

DENC notes that these caps are consistent with DENC's 2018 IRP and conform to the expected value of such facilities in PJM's capacity market. It also argues that they are consistent with FERC regulations that allow for the consideration of specific QF characteristics in determining avoided cost rates and with the complementary provisions of N.C.G.S. § 62-156. DENC explains that by having a single set of capacity rates, all QFs will see the same price signal, but application of the caps will allow capacity payments to be tailored to individual QF operating characteristics. DENC states that this would help ensure that rates paid to intermittent QFs reflect their actual capacity value and that customers not overpay for these QFs' output. DENC posits that this approach achieves the intent of the Commission's directive to consider establishing separate rate schedules for intermittent QFs, which is to recognize the limited capacity value of these QFs. DENC notes in addition that this approach will result in efficient administration of QF contracts by retaining a single set of standard seasonal capacity rates, with the cap applied only to intermittent QFs. *Id.* at 24-26.

In its Initial Comments the Public Staff objects to DENC's proposed cap. The Public Staff notes the steps taken by the Commission and General Assembly in 2017 to reduce the risk of overpayment for capacity to QFs. It also argues that capacity payments to an intermittent QF will inherently be lower than the capacity payments to a dispatchable QF if the seasonal allocation and capacity payment hours are accurately chosen to reflect the utility's seasons and hours of greatest capacity need. The Public Staff states that it reviewed generation data from 61 solar facilities representing over 430 MW in DENC's 2018 fuel factor proceeding, Docket No. E-22, Sub 558, and found that the average capacity factor during the twelve months ending June 2018 was 18.2%, with a maximum of 25.1%. The Public Staff also states that information DENC provided in discovery indicates that the capacity cap would affect tracking solar facilities with a capacity factor above 25.8%, which suggests that few QFs would actually hit the capacity cap. The Public Staff cautions, however, that this information is based on existing facilities that may have different efficiencies and operating characteristics than newer facilities eligible for these rates that may be constructed with more efficient inverters, more efficient panels, or other factors that may increase the output of their system relative to existing facilities. Public Staff Initial Comments at 60-62.

The Public Staff also questions DENC's approach of defining its seasonal allocation of capacity need to be consistent with its membership in the PJM market, when the capacity needs of the PJM market as a whole are different from the capacity needs of a utility operating in North Carolina. The Public Staff recommends that instead of the cap on capacity payments, DENC should evaluate alternative seasonal allocation and capacity payment hours that align more directly to DENC's system as opposed to the PJM system as a whole. *Id.* at 62-64.

In his affidavit, NCSEA witness Johnson claims that adopting more accurate price signals as he proposes would eliminate the potential that a QF will be over-compensated for capacity and therefore make DENC's proposed annual capacity payment cap unnecessary. Johnson Affidavit at 78.

In its Reply Comments, DENC explains that the proposed annual cap on capacity payments is an administratively efficient way to accomplish two goals. First, DENC argues that it links IRP principles to avoided cost payments. DENC states that it values solar capacity at 23% of nameplate capacity in its IRP, and that the cap accounts for that solar capacity value. Second, the cap provides a useful and reasonable way to reduce the risk that customers overpay for capacity beyond DENC's actual avoided costs. DENC acknowledges the progress made by House Bill 589 and the 2016 Sub 148 Order toward reducing the risk of customer overpayment, but states that that progress did not eliminate the need for the cap as a useful stopgap to prevent overpayment that could still occur due to potential imperfections in the rate design, peak hours selection, and CT seasonal cost allocations. DENC Reply Comments at 38.

In addition, noting the Public Staff's recognition that its calculated historical average solar capacity factor was based on existing solar facilities, DENC states that solar technology is advancing, and the lower historical capacity factors associated with existing units, many of which are fixed tilt, may not accurately represent future performance of solar resources, which could be tracking solar units. Given this uncertainty of new solar QF capacity factor performance in the future and the likelihood that new units will utilize tracking solar technology with higher capacity factors, DENC argues that the capacity payment cap would provide a good safeguard to protect customers from overpaying for capacity. *Id.* at 38-39.

Discussions and Conclusions

Based upon the foregoing and the entire record herein, the Commission agrees with the Public Staff that DENC's proposed capacity cap, which acts as a limit on payments, is unnecessary if DENC appropriately evaluates and adjust its seasonal allocation and capacity payment hours based on the specific characteristics of its system. Therefore, the Commission finds that it is inappropriate to approve DENC's proposed capacity cap for the purposes of calculating rates in this proceeding, and the Commission will direct DENC to appropriately revise its Schedule 19-FP rates to remove the capacity payment limits.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 48

The evidence supporting this finding is contained in DENC's verified Initial Statement and NCSEA witness Johnson's affidavit.

Summary of the Evidence

In its Initial Statement DENC acknowledges that in the 2016 Sub 148 Order the Commission ruled that it would require the Utilities to "address the PAF and to support their recommendations for PAF calculations based on their evidence of peak season equivalent availabilities for the utility fleets in total in [their] initial filings" in this proceeding. DENC proposes to use the fleet EA to determine the PAF, which it calculated to be 1.07 and applied to its proposed Schedule 19-FP capacity rates. DENC states that the EA represents the availability of the unit(s) during the defined period, and accounts for unit unavailability caused by planned, maintenance, and forced outages. DENC notes that it assumed peak seasons of June, July, August, and January-February in its PAF calculation, which PJM considers the critical months when system emergencies and performance assessment hours are expected. DENC Initial Statement at 32-33.

In its Initial Comments the Public Staff asserts that each utility's PAF should incorporate the respective utility's prospective EFOR, and not be based solely on historical availability data. It recommends that the Commission direct the Utilities to refile their fleet weighted average peak month EFORs using five years of historical data and at least five years of prospective data. The Public Staff asserts that the Utilities' historical data supports the use of June through August as summer peak months and December through February as winter peak months (and notes that DENC excluded December from its winter peak months). The Public Staff acknowledges, however, that DENC's proposed PAF of 1.07 based on historic operational data is an increase from DENC's 1.05 PAF approved by the Commission in the 2016 Sub 148 Order. Public Staff Initial Comments at 69-70.

In its Initial Comments NCSEA states that a PAF is used to ensure that QFs are not discriminated against in favor of rate-based generation and that the PAF should consider the availability of rate-based generation during all critical peak hours. NCSEA notes that the Commission states in its 2016 Sub 148 Order that the availability of a CT is not determinative for the purpose of calculating a PAF. NCSEA and witness Johnson, in his affidavit, also state that the Commission in that order discussed alternatives for calculating the PAF in future proceedings and indicates a preference for consistency between avoided cost filings and other routine filings. Witness Johnson notes the peak months used by the Utilities in their respective PAF calculations, but he does not oppose DENC's calculation or make a recommendation to the Commission specifically regarding DENC's PAF. NCSEA Initial Comments at 30-32.

In its Reply Comments the Public Staff states that although it initially advocated for the use of at least five years prospective EFOR data to bring to the forefront the "peak season" concept, subsequent to filing its Initial Comments the Public Staff better recognized the fundamental differences between EA and EFOR and the challenges associated with comparing the two separate metrics. The Public Staff also recognizes the difficulty of adding a prospective element to the PAF calculation as it would introduce subjectivity. As a result, the Public Staff proposes that if a rate-based metric is applied, the use of three to five years of historic data is appropriate. The Public Staff also asserts that an EFOR metric does not properly address other types of outages that can occur during a peak season and suggests that other reliability metrics used by NERC such as the EUOR or WEUOR could be an appropriate metric that takes into account outages that can occur during peak periods such as forced outages, maintenance outages, and derates. The Public Staff states that EUOR removes planned outages from the base calculation and therefore would not give a negative indication of utility unit performance during the critical peak seasons. Based on discussions with the Utilities, however, the Public Staff recommends that the Commission approve the initial PAF calculations proposed by the Utilities in their respective Initial Statements, but also direct the Public Staff, Utilities, and parties in this proceeding to discuss whether another metric, such as EUOR, may be a more appropriate reliability metric to support quantification of the PAF in future avoided cost proceedings. Public Staff Reply Comments at 14-16.

In its Reply Comments DENC opposes the Public Staff's suggestion of the weighted equivalent unplanned outage rate (WEUOR) to determine the PAF. DENC states that the WEUOR is an obscure metric that DENC does not calculate and that the EA metric DENC used is more appropriate based on the 2016 Sub 148 Order. DENC argues that the PAF should be determined based on three years of EA history as that measure provides the most meaningful information because it is actual, observable, and recent as opposed to five years of data which is less relevant due to generation unit changes such as unit fuel conversions. Prospective EA data, DENC details, would add subjectivity and unnecessary complication to the PAF calculation. DENC supports the Public Staff's shift away from using a prospective component in the PAF calculation. DENC Reply Comments at 39-40.

DENC also states that the peak periods it used in its PAF calculation correspond with the months PJM considers to be the peak months from a system operations perspective, when system emergencies would likely occur, and when planned outages would not be scheduled. DENC states that including December or March in its calculation would mean the majority of months in a year would be "peak" months, and that DENC uses these months for planned outages in order to spread out the spring and fall outages. DENC argues that including December or March data would increase the PAF and unfairly burden electric customers with increased QF capacity costs due to the Company's efforts to efficiently plan outages for its generation units. DENC states that including March and December would also run counter to the Commission's finding in the 2016 Sub 148 Order where the Commission states that "Public Staff's witnesses use of availability factor is flawed because it includes planned outages that a utility intentionally schedules for off-peak shoulder periods when electricity demand is low." DENC Reply Comments at 41-42 (quoting 2016 Sub 148 Order at 55).

In its Reply Comments NCSEA states that the calculation of the PAF should be forward-facing to account for technological improvements. NCSEA Reply Comments at 12. In its Reply Comments SACE asserts that based on historical data, the Utilities should include June and

September in their summer peak months and March and December in their winter peak months. SACE Reply Comments at 8.

Discussion and Conclusions

In the 2016 Sub 148 Order the Commission directed the Utilities to address the PAF and support their recommendations for PAF calculations based on evidence of peak season equivalent availabilities for their fleets in total in their initial filings in this proceeding.

Based upon the foregoing and the entire record herein, the Commission finds that DENC has satisfied this directive, and that its proposed PAF of 1.07 is appropriate for use in calculating its avoided capacity costs in this proceeding. Therefore, the Commission concludes that DENC's PAF of 1.07 should be approved for the reasons articulated by DENC and the Public Staff. The Commission finds persuasive the comments of DENC and the Public Staff as to the value of basing the PAF calculation on historical as opposed to prospective data. The Commission also finds that DENC's rationale for its assumed peak seasons to be reasonable, as those seasons represent the critical months that PJM considers to be the peak months from a system operations perspective when system emergencies would likely occur and when planned outages would not be scheduled.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 49 – 52

The evidence supporting these findings of fact is found in Duke's verified JIS and in the testimony of Duke witnesses Snider and Johnson, Public Staff witness Hinton, and SACE witness Glick.

Summary of the Evidence

A part of its Initial Statement Duke includes an amended Schedule PP PPA and Terms and Conditions to address modifications to a QF Facility that seeks to install battery storage or otherwise increase its energy output. Duke amends the Terms and Conditions for new PPAs to state that it may terminate or suspend purchases of electricity from the QF for "any material modification to the Facility without the Company's consent or otherwise delivering energy in excess of the estimated annual energy production of the Facility." JIS DEC Exhibit 4 and DEP Exhibit 4. The Terms and Conditions do not specifically define the term "material modification." A material modification is, however, a term defined in the NCIP.

Duke states that the right to sell power under the pre-existing PPA and standard offer rates should be limited to the QF as configured when it established a LEO and originally entered into the PPA. Duke states that adding batteries or other technologies for the storage and later injection of energy to an existing QF that has committed to sell power under then-effective PPA rates is an example of a material modification that could constitute an event of default resulting in termination of the PPA at Duke's election. JIS at 35. Amendments to Section 1.4 of the Schedule PP PPA and Section 4 of the Terms and Conditions propose to clarify that modifying a QF to increase the AC energy output or the delivered DC capacity of the facility would be an event of default. *Id.* at 38.

Duke specifically amends the terms and conditions to clarify the term "Contract Capacity" to include the estimated annual energy production of the facility. Duke further states that any such increase to the "Contract Capacity" will not be allowed if the QF seeks to retain its pre-existing standard offer PPA at "stale and significantly higher avoided cost rates." *Id.* at 35. Duke believes it would be inappropriate to compensate capital investment made today based "on stale avoided cost rates that were established many years in the past and which far exceed the currently-effective avoided cost rates." *Id.* at 35-36. Acceptance of such modifications would materially increase the financial obligations of Duke's customers at rates significantly above the current avoided cost.

In its Initial Comments the Public Staff agrees with Duke that the increased energy output of a QF that adds storage should be subject to the rates determined in the most recently effective avoided cost docket. Public Staff Initial Comments at 73. The Public Staff states that allowing a QF to increase its energy output by adding storage could significantly change the total cost of the QF's energy and capacity to the detriment ratepayers if, for example, the facility adds energy during on-peak periods as reflected in prior tariffs that do not reflect the utility's highest production cost hours today. *Id.* at 74, fn. 111. The Public Staff is concerned, however, that Duke's approach to requiring a new PPA at current avoided cost rates for the entire facility would disincentivize the adoption of new energy storage technologies at existing facilities, which also have the potential to benefit ratepayers by allowing the QF to operate it in such a way to provide energy and capacity during periods when the utility faces high production costs or critical demand. Further benefits could include operational controls that may also help to reduce the impacts associated with the intermittent, uncontrolled output from solar-only facilities. *Id.* at 74, fn. 112.

The Public Staff agrees with Duke that a QF seeking to add any new capability for energy output after execution of a System Impact Study (SIS) Agreement or execution of an Interconnection Agreement following the Fast Track Process or Supplemental Review pursuant to the NCIP should be required to receive authorization from the utility in order to ensure that the addition does not negatively impact the safe and reliable operation of the grid. *Id.* at 75. The Public Staff notes, however, that Duke does not specifically define the term "material modification" in its amendments to the Terms and Conditions. As that term is also used in the interconnection proceeding, the Public Staff recommends that Duke define the term explicitly. *Id.* at 77-78.

The Public Staff proposes an alternative approach to separately meter any additional energy output from the original facility and compensate the additional output at the then-current Commission-approved avoided cost rates without requiring the existing facility to forfeit payments under the terms of its pre-existing PPA. *Id.* at 76. The Public Staff states "that designating the addition of energy storage at an existing facility as a new and separate facility may result in unintended consequences, including loss of eligibility as a standard offer QF or a FERC-certified QF." *Id.* The Public Staff is also concerned that having multiple PPAs at the same site may result in timeframes that do not align, potentially causing confusion regarding QF eligibility *Id.* at 76-77.

In its Initial Comments NCSEA states that Duke provides "no limitation or quantification" on its proposed "unilateral authority to void a PPA if a QF increases its annual energy production above an estimated production number stated in the PPA," and that that "occurs on a regular basis for QFs." NCSEA Initial Comments at 55. NCSEA further states that the annual production number, which Duke proposed to use as the Contract Capacity, is an estimate that will vary up and down due to a variety of circumstances. *Id.* NCSEA asserts that it is commercially unreasonable to require that a QF never exceed its estimated annual energy production without risking termination of the PPA.

NCSEA argues that Duke's proposal violates PURPA's requirement that a utility purchase all of a QF's output provided that the QF does not exceed its nameplate capacity. *Id.* NCSEA disagrees with Duke's assertion that the right to sell under PURPA should be limited to the facility that established a LEO and originally entered the PPA. NCSEA states that the CPCN requirement was not intended to lock QFs into construction of a facility exactly as described in the CPCN application. *Id.*

In its Initial Comments SACE states that Duke's changes to the Terms and Conditions are troubling because coupling battery storage technologies with intermittent generation will allow the QF to sell energy and capacity at times of greatest value to the utility, grid operators, and ratepayers. SACE Initial Comments at 14. SACE further states that Duke's barriers to storage deployment discriminate against QFs, create economic inefficiencies, and miss opportunities to add value to the grid. *Id.*

In its Initial Comments NC WARN disagrees with Duke's changes to the Terms and Conditions that provide for early contract termination for changes in Contract Capacity or energy output, and states that the proposed amendments would give Duke the ability to deny a QF's request to add battery storage to an existing solar project for any reason and without limitations. NC WARN Initial Comments at 4.

In its Reply Comments Duke maintains the position that allowing QFs to add storage would disadvantage customers and result in potentially significant additional future payments to QFs in excess of current and projected avoided costs. Duke clarifies that the changes to the Schedule PP PPA and the Terms and Conditions are due to recent inquiries from developers of operating QFs desiring to make new investments in their facilities, such as installing additional solar panels, replacing existing panels with panels with greater capacity (known as "over-paneling"), or proposing to co-locate battery storage at a facility, and represent what Duke believes is already the case under the existing language — that Duke will not agree to modifications that will increase its and its customers' obligations to purchase energy at prior avoided cost rates. Duke Reply Comments at 134. Duke provides a chart depicting various scenarios and the overpayment risk to installing storage at existing QFs. *Id.* at 135, fig. 11.

Duke proposes to add the following new defined term "Material Alteration" to its amended Terms and Conditions to more clearly define what constitutes a material change to a facility:

> (f) "Material Alteration" as used in this Agreement shall mean a modification to the Facility which renders the Facility description specified in this Agreement inaccurate in any material sense as determined by Company in a commercially reasonable manner including, without limitation, (i) the addition of a Storage Resource; (ii) a modification which results in an increase to the Contract Capacity, Nameplate Capacity (in AC or DC), generating capacity (or similar term used in the Agreement) or the estimated annual energy production of the Facility (the

> "Existing Capacity"), or (iii) a modification which results in a decrease to the Existing Capacity by more than five (5) percent. Notwithstanding the foregoing, the *repair or replacement of equipment at the Facility (including solar panels) with like-kind equipment, which does not increase Existing Capacity or decrease the Existing Capacity by more than five percent (5%) shall not be considered a Material Alteration.*

Id. at 139 (emphasis added). The proposed definition will allow the repair or replacement of equipment at a facility with "like-kind equipment" to clarify that developers and owners may undertake routine operations and maintenance and replace equipment if the facility is impacted by storm damage. *Id.* at 139-40.

Regarding the Public Staff's recommendation in its Initial Comments to explore separately metering battery storage and compensating additional output at the current avoided cost rate, Duke states that it does not support the Public Staff's recommendation to allow amendments to prior standard offer PPAs to accommodate the addition of storage for contractual, technological, and regulatory policy reasons. First, contractually, Duke believes that a material alteration of a facility would require the consent of utility, and the failure to obtain consent would be a material breach of the contract. Second, from a technological perspective, Duke states that its current metering system does not have the capability to segregate or estimate the production of a solar QF separate from a co-located battery storage facility. Furthermore, if the battery is shifting the time of energy delivered it could result in inequities. For example, under the levelized rate concept, there would be overcompensation being paid to the QF because there would be higher deliveries and payments in the early years prior to the installation of battery storage when levelized rates are artificially high. Third, from a regulatory policy perspective, QFs and their investors have often selected the longest possible term of 15-year contracts in order to benefit from locking in higher avoided cost rates that are now projected to significantly exceed future avoided costs. Duke believes it would be inequitable to allow those facilities to leverage the current contractual relationship to sell more energy or to shift energy output in ways that were not contemplated when the contract was entered. *Id.* at 145-46. Finally, Duke states that it agrees with the Public Staff that there would be challenges in determining the eligibility for QF status as a small power production facility under PURPA. The potential co-location of battery storage with a solar facility raises federal and regulatory policy questions that have not fully been answered, including eligibility for 5-MW projects adding generation that will increase nameplate capacity of the facility as a whole and the potential violation of the half-mile rule. *Id.* at 147-48.

In its Reply Comments NCSEA states that energy storage is now cost-competitive and that there is likely to be substantial deployment before the next avoided cost biennial proceeding. NCSEA agrees with the Public Staff and SACE that the proposed additions to the PPA and Terms and Conditions regarding energy storage and increases to energy output are overly and unduly restrictive. NCSEA Reply Comments at 21-22. NCSEA agrees with SACE that the replacement of older solar panels with newer solar panels should not be considered a material modification that would require the QF to enter a new PPA. *Id.* at 22. NCSEA disagrees with the Public Staff's suggestion that increased energy output be separately metered and compensated at the most recently effective avoided cost rate. NCSEA asserts that the fact that a QF could increase its total revenue generated through the addition of energy storage is an insufficient reason "to violate the

PURPA rights of QFs." *Id.* A QF that is already providing electricity to the grid has already met the requirements to establish a LEO and adding energy does not void the LEO. *Id.* at 22-23.

SACE states in its Reply Comments that it agrees with the positions of the Public Staff, NCSEA, and NC WARN that a number of Duke's proposed amendments to the Schedule PP Terms and Conditions will likely discourage QF development, including the addition of energy storage. SACE states that it agrees with the Public Staff that it is not appropriate for a QF that adds storage to forfeit its existing PPA or to characterize the addition of energy storage as a new and separate facility. SACE Reply Comments at 17-18. SACE states that it does not consider it "appropriate at this time to require existing QFs that add storage or replace existing solar panels, but which do not exceed their AC capacity, to enter into new contracts with new avoided cost rates." *Id.* at 18. SACE believes "[r]equiring QFs to enter into bifurcated avoided cost rates when the QF is not exceeding its original AC capacity is inconsistent with PURPA's requirements." *Id.* Furthermore, SACE agrees with the Public Staff that "material modification" is undefined and that the term should be defined further with stakeholder input for the purposes of avoided cost contracts. SACE agrees with NCSEA that material modification is more appropriately addressed in the interconnection proceeding and believes that to the extent material modification is used in avoided cost contracts that Duke's definition is overly broad. *Id.*

On June 14, 2019, the Commission directed the parties to file testimony specifically addressing the avoided cost rate schedule and contract terms and conditions that would apply when a QF proposes to add battery storage. Three specific scenarios were identified for consideration: (i) where a QF has established a LEO to sell power to a utility, (ii) where a QF has executed a PPA with a utility to sell its power over a specified term, and (iii) where a QF has commenced operations and is now selling the electric output of the facility to the relevant utility pursuant to an established LEO and executed PPA.

Duke witness Snider testified that the proposed changes to the PPA and Terms and Conditions are meant to clarify that operational QFs should not be allowed to modify their generating facility in order to increase generation and that to allow that would be "unjust and unreasonable and would result in significant customer overpayment relative to the incremental generation value being put to the grid." Tr. vol. 2, 87. Witness Snider stated that the modifications are necessary to protect customers from overpayment at rates that exceed the utility's current avoided cost and that power being delivered today from QFs date as far back as the 2010 avoided cost proceeding, Docket No. E-100, Sub 127. *Id.* In quantifying the potential impacts to customers, witness Snider stated that Duke is committed to purchasing the full contracted-for output from over 3,600 MW of currently or to-be installed QF generating facilities, "all of which are subject to rate schedules approved in Docket No. E-100, Sub 140 or earlier vintages." *Id.* at 88.

Duke witness Johnson testified that Duke is not making any further changes to the proposed PPA and Terms and Conditions than those modifications proposed in Duke's Reply Comments. *Id.* at 261. He reiterated that Duke added the defined term "Material Alteration" in response to comments of the intervenors to more clearly describe what changes or alterations an operating QF can make in the normal course of operations and to signify when the QF must obtain prior authorization from Duke. *Id.* The addition of a Storage Resource, as that term is now also defined in the Terms and Conditions, would be a Material Alteration. *Id.* at 263. Witness Johnson also stated that Duke has clarified in the definition of Material Alteration that any changes, including routine maintenance, to existing facilities will be evaluated in a commercially reasonable manner. *Id.*

In response to the scenarios presented in the Commission's June 14, 2019 Order, witness Snider testified that a "committed" QF may not integrate battery storage without first obtaining Duke's consent, and, in all three scenarios, should enter into a new or modified PPA at the most recent avoided cost rates. Tr. vol. 2, 162-63. He further testified that "[a]llowing QF investors to integrate battery storage systems or any other technology that materially alters a QF's energy output or shifts power production under stale, legacy avoided cost rates would result in increased payments to QFs that exceed current avoided costs, in direct contravention of PURPA and HB 589's standard offer rate requirements." *Id.* at 166.

Witness Snider stated that once the LEO is established, both the QF and the utility are bound for the duration of the LEO or the contract. Duke believes it is inconsistent with PURPA and state law for a QF to rely upon an existing LEO to make new investments. Witness Snider cited FERC Order No. 69 in its implementation of PURPA, which states that while a LEO provides certainty to the QF and ensures it is not "deprived of benefits of its commitment as a result of changed circumstances," that it "can also work to preserve the bargain entered into by the electric utility." *Id.* at 167.

DENC witness Billingsley testified that DENC has not made any changes to the Schedule 19 tariffs or PPAs to specifically address the addition of battery storage. Tr. vol. 5, 58. DENC's position regarding all three scenarios presented in the Commission's June 14, 2019 Order is that a QF that seeks to add storage to a proposed or existing facility that has established a LEO or entered into a PPA would be required to establish a new LEO or execute a new PPA at current avoided cost rates. *Id.* Witness Billingsley testified that a QF that seeks to expand its maximum capacity or energy production, or to shift its hours of production under existing rates and terms would burden the Company and its customers with newly obligated overpayments at stale avoided cost rates in contravention of PURPA's requirement that utilities not pay more than their avoided cost for QF output. *Id.* at 59. The addition of battery storage would exacerbate the overpayment burden that the utility already faces, and "contradicts the requirement of PURPA that purchases at avoided cost rates be fair to both QFs and the utility (and its customers)." *Id.*

Witness Billingsley stated that nearly all solar QFs that executed PPAs during the Sub 136 and Sub 140 vintage biennial periods elected Option B, and that those hours no longer represent the utility's highest capacity value hours. Allowing existing QFs to deliver energy from storage during those periods with higher capacity payments would be contrary to the recent movement towards more granular rate design that would incent QFs to deliver energy during a higher value set of hours. *Id.* at 62-63. Witness Billingsley, when asked whether some of DENC's concerns would be alleviated if existing QFs were incentivized to produce energy during the newly proposed peak periods, agreed that DENC would like to send price signals during peak hours. *Id.* at 89.

Public Staff witness Hinton testified that the Public Staff reviewed the addition of the term "Material Alteration" and other changes made to the Terms and Conditions in Duke's Reply Comments and found that they addressed earlier concerns raised by the Public Staff and NCSEA.

He stated that the Public Staff is generally supportive of Duke's modifications but emphasized that a "degree of reasonableness" is appropriate regarding equipment replacement and repairs made by QFs. Witness Hinton testified that it is important that the modifications to the Terms and Conditions do not have the effect of discouraging efficient investments made by QFs, but also "recognize that material alterations made without reconsideration of the facility's interconnection study, and the avoided cost rates that are applicable to the QF, would be inappropriate." Tr. vol. 6, 321.

Public Staff witness Metz testified that the complementary function of energy storage, when paired with intermittent generation, can reduce needed system reserves by improving predictability of energy output, alleviate other challenges to the electrical grid, and increase the overall dependable capacity. Therefore, witness Metz stated that it is the Public Staff's position that "energy storage coupled with solar generation has the potential to provide benefits to ratepayers and should be appropriately encouraged and fairly treated." Tr. vol. 6, 349. He further testified that the challenge to the Commission is how to allow battery storage development with both future and existing solar QF generation and provide its benefits in a way that is fair to ratepayers. *Id.* at 330. He stated that he agrees with the Utilities that a "QF proposing to integrate battery storage should: (a) not be allowed to do so without the utility's consent; and (b) be required to enter into a new or modified power purchase agreement (PPA) at the Companies' then-current avoided cost rates." *Id.* at 331. Witness Metz stated that paying for additional energy and capacity at old, higher avoided cost rates that no longer reflect the actual avoided costs of the utility would be unfair to ratepayers, as they would "no longer be indifferent between energy supplied by a QF and energy generated by the utility." *Id.* at 333. However, witness Metz did not agree with the Utilities that a QF that adds storage or increases output should lose its eligibility for the rates it established for its original facility output (contract capacity and energy). *Id.* at 332. Rather, any "additional energy" put to the electrical grid from an already existing QF, whether commercially operational or studied as part of the facility's original interconnection request, should be compensated at the most current avoided cost rates and schedules. *Id.* at 349.

Witness Metz testified that it is possible for a QF to produce "additional energy" without adding battery storage by deciding to "re-panel" or "over-panel" to increase its DC capacity, which does not necessarily increase nameplate capacity due to inverter settings and other utility equipment limitations. These modifications, however, can result in faster ramp rates and increased "clipped" energy. *Id.* at 334-35. Witness Metz stated that under the proposed definition of Material Alteration, over-paneling and re-paneling would likely not be considered a Material Alteration so long as Existing Capacity is not increased. In response to questions by the Commission, witness Metz stated that it was possible to add energy storage without increasing the overall output of the facility, but there would have to be validation of certain equipment and contractual terms and conditions developed to ensure the Facility's output is not increased. *Id.* at 433.

With regard to adding storage and separately compensating the additional energy output of the facility, witness Metz testified that there are multiple possibilities to measure the output of co-located batteries, but that it would likely require further restrictions of commercial terms and conditions and may prove uneconomical. Witness Metz stated that in addition to engineering and technical challenges, impacts on the interconnection queue as well as the applicable contract terms and conditions would have to be further considered. *Id.* at 344. For example, if an existing facility sought to add battery storage and took the position that the storage could be separately measured, a methodology would have to be created to develop a baseline of current output for comparison purposes and incorporated into the commercial terms and conditions. *Id.* at 345. Witness Metz proposed a focused stakeholder discussion with an accelerated timeline to explore and develop a deployable energy storage solution for existing QFs and to identify specific challenges that prevent the commercial viability of adding energy storage to existing facilities. *Id.* at 351.

Ecoplexus witness Wallace testified that Ecoplexus agrees with the approach recommended by the Public Staff in its Initial Comments to separately meter any additional output at the then-current Commission-approved avoided cost rates without requiring the existing facility to forfeit payments under the terms of its current PPA. Tr. vol. 5, 347. He stated that there are multiple methods to measure the energy output of a battery system, including: (1) "transferring that data directly from the Energy Management System provided by the battery storage provider through network communications onsite;" and (2) "add[ing] a DC meter to the storage output so that energy output could be compensated at the current avoided cost rates and separated from the pre-existing PPA." *Id.* In the first option, the battery management system (BMS) collects information in real time and delivers it to the Energy Storage System (ESS), which processes and analyzes the data. BMS and ESS integrators provide a cloud-based system for monitoring, sharing, and displaying data. *Id.* at 347-48. In the second option, a DC meter could be added for each storage block in addition to the AC revenue meter installed at the point of interconnection, which will remain in place. *Id.* at 349. While witness Wallace stated that there "are no ANSI or IEEE standards in place for DC-meters," there are companies "that can meet [the] ANSI C12.1 accuracy specification." *Id.* Witness Wallace testified that if DC energy can be measured with revenue grade accuracy, a "simple ratio can be calculated and used at the [utility's] AC meter to decipher energy from the array as opposed to energy from the storage system to ensure the proper rate is assigned." *Id.* at 350. Lastly, he noted two outstanding issues that would need to be discussed and considered collaboratively: (1) a metering and communications standard, and (2) commercial PPA terms, and suggested a stakeholder process with a formal proposal to be submitted to the Commission within 150 days. *Id.* at 351.

NCSEA witness Norris testified that energy storage will play an increasingly significant role in enabling "a more affordable, reliable, and sustainable electricity system." Tr. vol. 6, 124. He stated that NCSEA and Cypress Creek believe that "it is incumbent upon the Commission to make decisive regulatory interventions to remove barriers to market entry for energy storage," and that it is of substantial importance in this State for committed QFs because more utility-scale solar is installed in North Carolina than any other state except California. *Id.* at 125. Witness Norris testified that "there is nothing in the standard offer terms and conditions that prohibits a QF from making equipment changes that change the schedule of the output," and "there is nothing in the standard offer QF PPA that prohibits or requires the Utility's consent for equipment changes." *Id.* at 150. He stated that "it is the view of NCSEA that committed generators are fully entitled to add storage under the terms and conditions of the standard offer PPA." *Id.* However, NCSEA offered to accept the alternative arrangement proposed by the Public Staff that output from the storage equipment would be compensated at the most recently determined avoided cost rate. *Id.* at 151. However, the avoided cost rate sought by NCSEA is the ten-year avoided cost rate. Under NCSEA's approach, the modified PPA would also maintain the remainder of the original PPA's terms and conditions, including the remaining PPA tenor. This would properly value the capacity and will allow the QF to attract financing. A five-year avoided cost rate would "undercut or fully eliminate the capacity value of the storage equipment and make it wholly unfinanceable." *Id.* at 147.

Witness Norris testified that the Utilities' position that any committed generator that adds storage must terminate its existing PPA or LEO and seek an entirely new PPA would "wholly obstruct the addition of storage resources." *Id.* at 151. He stated that ratepayers could benefit from the addition of storage by "including bulk energy time shifting, peak capacity deferral, interconnection efficiency, [and] reduced solar curtailment" among other benefits. *Id.* at 152. Witness Norris also testified that the addition of battery storage could smooth the production curve in a way that could obviate the need for the integration services charge. *Id.* at 177.

Witness Norris disagreed with DENC witness Billingsley's assertion that a QF with a LEO under the Sub 136 or Sub 140 tariffs should not be able to deviate from the configuration specified in its CPCN or FERC Form 556 without losing its LEO. Witness Norris stated that if a QF changes its facility, it must file an updated form and inform the Commission, but that hundreds of such amendments have been made and approved by the Commission or recertified by the FERC without voiding the established LEO.

In his testimony SACE witness Glick recommended that the Commission reject Duke's proposed changes to the Terms and Conditions, require Duke to honor existing contracts with QFs that integrate battery storage, and develop a modified rate design proposal for existing QFs that seek to integrate battery storage. *Id.* at 287-88. Witness Glick stated that as long as the QF does not increase its AC capacity, then "the utility has no reasonable basis to regulate the operation of individual components on the operator side of the meter." *Id.* at 274.

In joint supplemental rebuttal testimony, Duke witnesses Snider, Johnson, and Wheeler reiterated Duke's position that a committed QF proposing to integrate energy storage should not be able to do so without the utility's consent and should enter into a new PPA at current avoided cost rates. Tr. vol. 2, 176. Duke witness Snider testified that Duke is not opposed to entering a new PPA or negotiating a modified PPA if an existing QF proposes adding storage. *Id.* Witness Snider disagreed with NCSEA that the addition of storage to operating QFs will inherently create benefits for consumers. *Id.* at 181-82. Witness Snider stated that under the compromise position, even if "all the complex federal and state regulatory issues, contract law issues, and technical interconnection and metering issues" are resolved, customers will at best only be indifferent to adding storage because "it would be procured from an uncontrolled must-take QF generator being dispatched to maximize revenue and being paid at the utility's full avoided cost value rather than at competitively bid prices." *Id.* at 183.

Witness Snider further testified that if the Commission accepts the compromise, the QF owner seeking to add storage should be required to offer additional consideration that benefits customers in exchange for Duke agreeing to modify the existing commitment to purchase. *Id.* at 184-85. With regard to NCSEA's position that the Utilities should offer a standard offer avoided cost rate for additional output from a storage facility of ten years, witness Snider stated that this is a deviation from the express requirements of House Bill 589. *Id.*

Duke witness Wheeler stated that he has several concerns with Ecoplexus' proposal to measure energy storage output on the DC side of the power inverter and point of interconnection with the Duke system. *Id.* at 147-48. First, it is Duke's business practice to install metering exclusively on the utility's side of the point of interconnection; if it is installed on the QF side, the QF would have the opportunity to change the operation of the equipment without the utility's knowledge or control. Second, as witness Wallace admits, no ANSI standards currently exist to judge the accuracy of the meter data logger proposed in witness Wallace's testimony. Tr. vol. 2, 147-49.

Duke witness Johnson testified that he disagrees with NCSEA's assertion that energy shifting is currently allowed under Duke's avoided cost tariffs. *Id.* at 202-04. He stated that a unilateral change such as adding storage to a committed facility without obtaining Duke's consent would be an event of default. *Id.* at 204.

In responsive testimony, Public Staff witness Metz noted that Duke should clarify the definition of "Material Alteration" by adding a set of commas to make it unambiguous that a decrease of only 5% would not be considered a material alteration whereas any increase would be a material alteration. Tr. vol. 5, 338, fn. 22. Witness Johnson testified that Duke has no objection to witness Metz's recommendation for the grammatical clarification. Tr. vol. 2, 204.

In supplemental rebuttal testimony, DENC witness Billingsley stated, "[T]he Company believes that allowing the existing solar generation facility to continue to receive the original rates for which it was eligible while applying current rates to the output from the battery addition, appears a reasonable approach." Tr. vol. 5, 69. He also stated that DENC would be willing to participate in a working group to address various technological and commercial challenges, and that these issues would need to be studied and addressed before the "compromise approach could be fully implemented." *Id.* at 69-70.

Discussion and Conclusions

With regard to Duke's proposed changes to its Terms and Conditions, the Commission distinguishes between the two issues in contention between the parties: (1) whether regular maintenance of a facility or repair after a storm is a material change that can lead to default of the existing PPA; and (2) whether upgrading the facility to increase its energy output by re-paneling, over-paneling, or co-locating energy storage is a material change that can trigger default of the existing PPA. Duke in its Reply Comments adds the defined term "Material Alteration" to the Schedule PP PPA and Terms and Conditions to more clearly define the instances of what is a material change that requires the utility's consent, and that without consent may lead to default of an existing PPA.

With regard to the first issue, the Commission shares the concerns raised by the intervenors and the Public Staff regarding the term "Material Alteration." The Commission agrees with the Public Staff that QFs often complete maintenance on their facilities that could increase the energy or capacity such as replacing existing solar panels with newer panels, or re-paneling, without first obtaining the consent of the utility, and that this type of maintenance should not trigger a default of the existing PPA. The Commission concludes that Duke has adequately addressed these concerns with the defined term "Material Alteration" which expressly allows replacement of "like-kind" equipment and provides that material alterations will be evaluated by DEC and DEP in a "commercially reasonable manner."

The Commission also agrees with Duke, DENC, and the Public Staff that the right to sell power under a pre-existing PPA and standard offer rates should be limited to the facility that originally entered into the PPA. The Commission finds the evidence and positions in opposition to Duke and the Public Staff's view to be unpersuasive. However, the Commission also agrees with NCSEA that the CPCN requirement was not intended to lock QFs into the construction of a facility exactly as described in the CPCN application, and that the Commission has approved amendments to CPCNs without voiding the facility's LEO. As NCSEA argues, those amendments are usually limited in scope and do not involve changes to the facility that would require reconsideration of the facility's interconnection study or substantially increase the lifetime energy output or revenue potential of the facility.

For existing PPAs, material changes to the capacity of the QF should be authorized by the utility. However, as stated above the evaluation of any material alteration should be treated in a commercially reasonable manner. The Commission agrees that regular maintenance and repair of a facility after a storm, or similar instances that occur on a normal basis, should be treated within the normal course of operations and should not be considered a change that would allow the utility to void the existing PPA. For the reasons articulated by the Public Staff, the Commission finds that this modification to the Terms and Conditions is reasonable. Therefore, the Commission will approve the use of these revised Terms and Conditions.

Turning to the second issue, the Commission agrees with the Utilities and the Public Staff that it is inappropriate to compensate QFs for new capacity and energy at prior avoided cost rates under contracts that do not reflect current avoided costs and do not align price signals with the highest needed capacity windows. However, the Commission recognizes the concerns raised by several intervenor-parties and the Public Staff that requiring existing or "committed QFs" to enter into a new PPA and forfeit prior, higher avoided cost rates will discourage QFs from adding storage, which if allowed under new rate design hours, could allow intermittent generation to sell energy and capacity at times of greatest value to the utility and its ratepayers.

The Commission finds persuasive NCSEA's argument that removing barriers to energy storage is particularly important in North Carolina because the amount of utility-scale solar that is already installed surpasses that of any other state except California. The Commission also notes the testimony of NCSEA's witnesses that energy storage is now a cost-competitive option, that there is likely to be a substantial deployment of storage before the next avoided cost biennial proceeding, and that energy storage will play a significant role in enabling a more affordable, reliable, and sustainable electricity system. NCSEA's witnesses further testified that NCSEA is willing to accept the "compromise" suggested by the Public Staff to explore separately metering battery storage and compensating additional output at the then-current avoided cost rate. NCSEA states though, that this may not be an economically viable alternative at this time and that the Commission would need to ensure that those QFs received the ten-year avoided cost rate for the additional output. The Commission determines that it is premature to resolve this issue at this time.

Instead, for reasons discussed further below, the Commission will seek more detailed discussion on this issue through the stakeholder process required by this Order.

The Commission disagrees, however, with SACE that a QF should be allowed to add energy storage and be compensated at prior avoided cost rates for the additional energy added to the system not contemplated in the original PPA. As stated above the addition of energy storage to an existing QF is a material change to the terms of the prior contract and requires the utility's consent. Allowing a QF to modify its facility to substantially increase energy output and be compensated at prior avoided cost rates would result in significant overpayment beyond the current avoided cost, which would be unfair to ratepayers.

The Commission agrees with all the parties that allowing QFs to add storage at bifurcated avoided cost rates raises a multitude of challenging administrative and regulatory issues, including the development of metering and communication standards and new commercial PPA terms, that have not been fully considered in this proceeding. For that reason, the Commission finds that it is also premature at this time to decide whether the compromise position is appropriate. Rather, the Commission finds it appropriate to continue to investigate the proposed compromise as a potential solution to properly encourage the addition of battery storage in a manner that is fair to ratepayers.

The Commission is encouraged by Duke and DENC's willingness to enter a new PPA or negotiate a modified PPA if an existing QF proposes adding storage. The compromise appears to be a reasonable approach to resolve the various technological and commercial challenges. Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate for the parties to further discuss how to integrate storage with solar through a stakeholder process that would specifically address the complexities of modifying existing facilities that request to add capacity through the co-location of batteries. Therefore, the Commission directs Duke to organize a stakeholder group and will require Duke and DENC to report to the Commission on the results of the process on or before September 1, 2020.[1] The Commission directs the Public Staff to report on the organization of the stakeholder process, as well as the schedule, through an appropriate filing in this docket within 30 days of the date of this Order. The Commission's goal for the stakeholder process is to create a forum to: (a) identify critical issues that are barriers to the addition of energy storage to existing facilities, (b) develop solutions that will encourage deployment of energy storage, (c) further identify specific challenges that prevent the commercial viability, and (d) provide certainty to QFs that are considering the addition of an energy storage component to their electric generating facilities. The stakeholder process should be comprehensive in its consideration of all use cases for adding an energy storage component to a committed QF's electric generating facility. The report shall address, at a minimum, the following categories:

[1] In light of the present public health emergency resulting from the impacts of COVID-19, the Commission directs Duke to conduct the stakeholder group virtually.

I. Technology
   (a) Identify the metering challenges for AC and DC measured systems.
   (b) Propose solutions for AC and DC measured systems.
   (c) Analyze cost of design and implementation for both the facility and utility.
   (d) Identify and quantify specific ancillary services that can be provided by QFs coupled with energy storage.

II. Commercial
   (a) Report on what existing commercial terms and conditions are preventive barriers for implementation.
   (b) Propose solutions to remove or mitigate preventive barriers.
   (c) Report on how to accomplish billing and payment for separately metered systems.

III. Regulatory
   (a) Identify and propose solutions to regulatory barriers, including without limitation whether the addition of energy storage to an existing QF requires an amendment to the QF's CPCN or a wholly separate CPCN for the energy storage facility.
   (b) Propose the appropriate avoided cost rates and terms of the PPA applicable to the energy storage element of an existing QF coupled with energy storage.
   (c) Propose how costs should be recovered (or payment made) for identifiable and quantifiable specific ancillary services provided by the QF coupled with energy storage.

The report shall identify the areas of consensus reached among the stakeholders, and with respect to those areas where the stakeholders fail to reach consensus, the Commission will require Duke to provide the Commission with a recommended resolution. To the extent the Public Staff does not agree with any of the recommendations in the report, the Commission directs the Public Staff to file a separate report setting forth its recommendation(s) and basis therefor on September 1, 2020. The Commission will proceed as appropriate in considering the report(s) of the stakeholder group's activity.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 53

The evidence supporting this finding of fact is found in the verified Joint Comments and Proposed Rates of WCU and New River and the entire record herein.

In their Joint Comments WCU proposes to continue to pay variable rates based on its wholesale cost of power; New River proposes to continue to offer variable rates based on DEC's Schedule PP, but will not recover the administrative charge to suppliers found in Schedule PP. WCU and New River each further propose to offer long-term fixed price rates approved for DEC's Schedule PP, but again, New River will not recover the administrative charge found in Schedule PP. DEC is WCU's all requirements supplier, and it is indirectly New River's through Blue Ridge Electric Membership Corporation (Blue Ridge). Joint Comments at 2-3.

For both WCU and New River this is the same approach approved by the Commission in the 2016 Sub 148 Proceeding. As further provided in the 2016 Sub 148 Proceeding, N.C.G.S. § 62-156, as amended, provides for long-term contracts of up to ten years under the standard offer, as implemented by DEC in that docket and found above to be appropriate for use in this proceeding No parties filed any comments or objections to WCU's and New River's proposals.

The Commission therefore concludes, based upon the foregoing and the entire record herein, that WCU's and New River's rate proposals based on DEC's Schedule PP should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC, DEP, and DENC shall offer long-term levelized capacity payments and energy payments for ten-year periods as standard options to all non-hydroelectric QFs contracting to sell 1 MW or less capacity. The standard ten-year levelized rate option should include a condition making contracts renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors, or (2) set by arbitration;

2. That DENC shall continue to offer, as an alternative to avoided cost rates derived using the Peaker Method, avoided cost rates based upon market-clearing prices derived from the markets operated by PJM, subject to the same conditions as approved in the Commission's 2006 Sub 106 Order and most recently restated in the 2016 Sub 148 Order;

3. That DEC, DEP, and DENC shall offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (a) participating in the utility's competitive bidding process, (b) negotiating a contract and rates with the utility, or (c) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding;

4. That DEC and DEP shall file revised Schedule PP tariffs reflecting the energy and capacity rate design consistent with the April 18, 2019, Rate Design Stipulation between Duke and the Public Staff;

5. That, for the purposes of calculating avoided capacity rates in this proceeding, DEC should use seasonal allocation weightings of 90% for winter and 10% for summer, and DEP should use seasonal allocation weightings of 100% for winter.

6. That Duke's assumptions regarding the availability of DSM programs for reducing winter peak demand are reasonable and appropriate for the purposes of calculating avoided capacity rates in this proceeding, but Duke should place additional emphasis on defining and implementing cost-effective DSM programs that will be available to respond to winter demands;

7. That Duke shall evaluate methods to better align the Utilities' avoided cost rates with actual real-time system conditions to enable QFs to maximize their facilities' value to ratepayers through real-time pricing or other tariffs that provide more granular rate structures and price signals, and if found to be appropriate, should offer an RTP-based avoided cost tariff as an optional alternative to their Schedule PP in the next avoided cost proceeding;

8. That the requirements of Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6) shall be waived, and that until such time as the Commission adopts revisions to these Rules applicants for a certificate of public convenience and necessity pursuant to Rules R8-64 and R8-71(k) should, instead of the information currently called for in Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6), submit the "projected annual hourly production profile for the first full year of operation of the renewable energy facility in kilowatt-hours, including an explanation of potential factors influencing the shape of the production profile, including fixed tilt or tracking panel arrays, inverter loading ratio, over-paneling, clipped energy, or inverter AC output";

9. That in the next biennial avoided cost proceeding, the Utilities shall evaluate and apply, consistent with the conclusions reached in this Order, cost increments and decrements to the publicly available CT cost estimates, including the use of brownfield sites, existing infrastructure, decrements for electrical and natural gas connections, and other balance of plant items, to the extent it is likely that this existing infrastructure is used to meet future capacity additions by the utility;

10. That DEC, DEP, and DENC shall continue to calculate avoided capacity costs using the Peaker Method and include a levelized payment for capacity over the term of the contract that provides a payment for capacity in years that the utility's IRP forecast period demonstrates a capacity need, consistent with N.C.G.S. § 62-156(b)(3);

11. That DEC and DEP shall use a PAF of 1.05 and DENC a PAF of 1.07 in their respective avoided cost calculations for all QFs other than hydroelectric QFs with no storage capability and no other type of generation.

12. That DEC and DEP shall use a PAF of 2.0 in their avoided cost calculations for hydroelectric QFs with no storage capability and no other type of generation;

13. That the Utilities, with input from the Public Staff, shall evaluate appropriateness of using other reliability indices, specifically the EUOR metric, to support development of the PAF prior to the next biennial avoided cost filing;

14. That DENC shall continue to calculate rates that reflect the elimination of the line loss adder of 3% from its standard offer avoided cost payments to solar QFs on its distribution network;

15. That DEC and DEP shall continue to include a line loss adder in their standard offer avoided cost calculations for distribution-connected QFs, but shall study the effects of QFs on their distribution grid to determine the extent of backflow at substations prior to the next biennial avoided cost proceeding;

16. That the Utilities, for purposes of determining the first year of capacity need for negotiated contracts and for CPRE Tranche 2, shall update their avoided capacity calculations to reflect any changes in the utility's first year of undesignated capacity need as presented in their next IRP;

17. That beginning with the 2020 IRP, the Utilities shall include a specific statement of capacity to be used to determine the first year of avoidable capacity need in the next biennial avoided cost proceeding;

18. That the Utilities shall amend their standard offer rate schedules to recognize that a swine or poultry waste-fueled generator, or a hydroelectric facility with a capacity of 5 MW or less in capacity that has a power purchase agreement in effect as of July 27, 2017, which commits to sell and deliver energy and capacity for a new fixed contract term prior to the termination of the QF's existing contract term is avoiding a future capacity need for these designated resource types beginning in the first year following the QF's existing PPA, pursuant to N.C.G.S. § 62-156(b)(3), as amended. For other types of QF generation, the Utilities shall recognize a QF's commitment to sell and deliver energy and capacity over a future fixed term as avoiding an undesignated future capacity need beginning only in the first year when there is an avoidable capacity need identified in DEC's, DEP's, or DENC's most recent IRP;

19. That the Utilities shall continue to assume an in-service date in the first year following the filing of new avoided cost tariffs for standard offer QFs. A utility and QF negotiating a PPA may agree to a presumed in-service date for rate calculation purposes that takes into account the future in-service date of the QF generator, not to exceed two years in the future;

20. That DEC and DEP shall continue to calculate their avoided energy costs using forward natural gas prices for no more than eight years before using the fundamental forecast data for the remainder of the planning period, and DENC shall use its proposed fuel forecasting methodology in calculating avoided energy costs in this proceeding;

21. That DEC and DEP shall consider site- and project-specific characteristics during contract negotiations with QFs not eligible for the standard offer contract and include a T&D capacity adder if a project can provide real and measurable avoided transmission benefits;

22. That the integration services charges proposed by DEC ($1.10/MWh) and DEP ($2.39/MWh) shall be used in calculating rates in this proceeding as a decrement to DEC and

DEP's avoided energy rates, which shall apply prospectively for the duration of the contract, consistent with the conclusions reached in this Order;

23. That DEC and DEP shall not apply the integration services charge to a QF that qualifies as a "controlled solar generator";

24. That Duke shall include in its initial filings in the next biennial avoided cost proceeding an evaluation of whether a QF that can sufficiently demonstrate its ability, and contractually obligates itself, to operate in a manner that provides positive ancillary service benefits at a lower cost than the utility's own conventional resources, should be appropriately compensated for those benefits, and an identification of mechanisms to quantify the ancillary service benefits that such innovative QFs can provide;

25. That Duke shall submit the Astrapé Study methodology to an independent technical review as described in this Order and include the results of that review and any revisions to that methodology that is supported by the results of that review in its initial filing in the 2020 avoided cost proceeding;

26. That DENC's proposed rate design shall be used in calculating DENC's rates in this proceeding;

27. That DENC's proposed seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons shall be used in calculating DENC's rates in this proceeding;

28. That DENC's proposed input assumptions to be used in determining its proposed energy rates, including those related to fuel hedging activities and the LMP adjustment shall be used in calculating DENC's rates in this proceeding;

29. That DENC's proposed re-dispatch charge of $0.78/MWh shall be used in calculating DENC's rates in this proceeding;

30. That Duke's proposed modifications to its Terms and Conditions are approved;

31. That, Duke shall organize a virtual stakeholder process to address issues related to the addition of energy storage at an existing QF as described in this Order. The Public Staff shall make a filing, within 30 days of the date of this Order, on the organization and schedule for this stakeholder process. The Utilities, and Public Staff as necessary, shall report the results of the stakeholder process to the Commission through an appropriate filing in this docket on or before September 1, 2020;

32. That WCU's and New River's proposals to offer variable rates based upon their wholesale cost of power and to offer long-term fixed price rates that track DEC's Commission-approved avoided cost rates for QFs interconnected at distribution are approved; and

33. That, within 30 days after the date of this Order, the Utilities shall file revised versions of their rate schedules and standard contracts in redline and clean versions that comply with the rate methodologies and contract terms approved in this Order, to become effective 15 days after the filing date unless specific objections as to the accuracy of the calculations, except to the extent that filings previously submitted in response to the Notice of Decision and Supplemental Notice of Decision accurately reflect the conclusions reached in this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of April, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Joann R. Snyder, Deputy Clerk

DOCKET NO. E-100, SUB 158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018	)))	ORDER DENYING MOTION FOR RECONSIDERATION

BY THE COMMISSION: On June 15, 2020, the North Carolina Sustainable Energy Association (NCSEA) and the North Carolina Clean Energy Business Alliance (NCCEBA) filed a Joint Motion for Reconsideration and Clarification of the Commission's April 15, 2020 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in the above-captioned docket (April 15 Order). As detailed below, the Commission denies the motion for reconsideration of the April 15 Order but provides clarification and orders that certain filings be made in the next avoided cost proceeding.

STANDARD OF REVIEW

In their Joint Motion, NCSEA and NCCEBA request reconsideration pursuant to N.C. Gen. Stat. § 62-80 of four issues as described below that were decided by the Commission in its April 15 Order. As provided in N.C.G.S. § 62-80, "[t]he 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." The Commission's decision to rescind, alter, or amend an order upon reconsideration under N.C.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, 293-94, 494 S.E.2d 621, 626, *rev. denied*, 348 N.C. 78, 505 S.E.2d 886 (1998).

ISSUES FOR RECONSIDERATION

Solar Integration Services Charge Technical Review Committee

In the April 15 Order the Commission found that it is appropriate to require Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP, and together with DEC, Duke or the Companies), to prospectively apply an integration services charge (or solar integration services charge (SISC)) to all new uncontrolled solar generators that commit to sell and deliver power into the DEC and DEP systems on or after November 1, 2018. April 15 Order at 12 (Finding of Fact No. 35). The Commission approved amounts for DEC's and DEP's SISC based upon the results of a Solar Ancillary Services Study performed by Astrapé Consulting (Astrapé Study). As explained in the Commission's discussion:

> After careful consideration of such evidence and that no party otherwise contested or disputed such evidence, the Commission determines that DEC and DEP are incurring increased intra-hour ancillary services costs to integrate the "Existing plus Transition" level of solar [qualifying facilities (QFs)] into the DEC and DEP systems. Therefore, for reasons discussed above it is appropriate to require DEC and DEP to account for these costs when calculating the costs and benefits resulting from the purchase of energy and capacity from solar QFs.
>
> In determining whether the quantification of Duke's ancillary services costs is reasonable, the Commission finds the testimony of Duke witness Wintermantel, including the Astrapé Study he sponsored as an exhibit, to be quite persuasive. The independent review conducted by the Public Staff, as described by witness Thomas, lends further credibility to Duke's evidence. Further, the agreements reached in the SISC Stipulation reflect the give-and-take in negotiations, and the Commission finds the testimony in support thereof to be quite persuasive. Finally, while NCSEA witness Beach and [Southern Alliance for Clean Energy (SACE)] witness Kirby have advanced reasonable and well-articulated criticisms of this evidence, the Commission determines that Duke and the Public Staff have adequately addressed these criticisms sufficient to rebut these arguments. In summary, the Commission gives weight to the testimony of witnesses Wintermantel and Thomas, and based upon a review of the foregoing evidence and the entire record herein finds that the results of the Astrapé Study that an additional 26 MW of load following reserves are required to integrate 840 MW of solar in DEC at an average cost of $1.10/MWh, and that an additional 166 MW of load following reserves are required to integrate 2,950 MW of solar in DEP at an average cost of $2.39/MWh are reasonable for use in this proceeding. The Commission further finds that it is appropriate for Duke to prospectively apply the integration services charge to all new uncontrolled solar generators that commit to sell and deliver power into the DEC and DEP systems on or after November 1, 2018, and to any pre-existing solar QF not subject to the

> integration services charge committing to sell to Duke under a new [purchase power agreement (PPA)] in the future.

Id. at 92-93. The Commission further found, however, as follows: (1) "The Astrapé Study methodology used to quantify DEC's and DEP's increased ancillary services costs and to calculate each utility's integration services charge presents novel and complex issues that warrant further consideration," and (2) "It is appropriate to require DEC and DEP to submit the Astrapé Study methodology to an independent technical review and to include the results of that review and any revisions to the methodology that is supported by the results of that review in its initial filing in the 2020 biennial avoided cost proceeding." *Id.* at 12-13 (Findings of Fact Nos. 40, 42).[1] The Commission, therefore, ordered Duke to "submit the Astrapé Study methodology to an independent technical review . . . and include the results of that review and any revisions to that methodology that is supported by the results of that review in its initial filing in the 2020 avoided cost proceeding." *Id.* at 136 (Ordering Paragraph No. 25). As more fully described in the order:

> [T]he Commission agrees with NCCEBA, NCSEA, and SACE that the Commission would benefit from the results of an independent technical review of the Astrapé Study to inform future biennial avoided cost proceedings where similar issues will be reviewed. Therefore, the Commission directs Duke to assemble a technical review committee to provide a review of the Astrapé Study. The technical review committee shall be comprised of individuals, not otherwise affiliated with Duke or any of its affiliates or organizations in which Duke is a member, who have technical expertise, knowledge, and experience related to the integration of solar generation as well as the development of complex research, development, and modeling. The committee should include personnel employed by the National Laboratories with relevant experience and expertise. The purpose of the work with a technical review committee is to provide an in-depth review of the study methodology and the model used for system simulations. The technical review committee should provide specific comments or feedback to Duke in the form of a report, which report is to be included in the initial filing made in Duke's 2020 biennial avoided cost proceeding.

Id. at 95.

Motion for Reconsideration

In their Joint Motion NCSEA and NCCEBA continue to assert that the Astrapé Study contained methodological flaws and suffered from insufficient review, and they applaud the Commission's decision to direct Duke to assemble a technical review committee to review the Astrapé Study. NCSEA and NCCEBA protest, however, that there is no requirement for transparency as to the formation of the technical review committee, and they request the opportunity to observe and monitor the process as it progresses, including the ability to join conference calls, receive notifications and status updates, and review draft documents that are

[1] These findings of fact were first made in the Supplemental Notice of Decision issued in this docket on October 17, 2019 (Findings of Fact Nos. 11-12).

provided by the committee to Duke. NCSEA and NCCEBA state that they desire transparency as to the individuals chosen by Duke to make up the committee, including how their credentials fit the list of criteria set forth by the Commission, and believe that intervenors should be afforded the opportunity to provide comments regarding the makeup of the technical review committee as well as the process through which the committee reviewed the study and provided results to Duke. Lastly, NCSEA and NCCEBA state that Duke should include intervenor comments provided to Duke regarding the committee selection and process as part of the report that Duke will include in its initial filing in the 2020 avoided cost proceeding.

Discussion and Conclusions

As noted above, the requirement for an independent technical review of the Astrapé Study methodology was set forth in the Supplemental Notice of Decision in October. In the April 15 Order the Commission laid out specific, detailed expectations for the makeup of the technical review committee: "The committee should include personnel employed by the National Laboratories with relevant experience and expertise." The Commission is seeking an unbiased, objective, third-party expert review and analysis of the methodology employed by Astrapé to quantify DEC's and DEP's increased ancillary services costs and to calculate each utility's integration services charge. The Commission expects a truly independent review by knowledgeable experts and for Duke to provide to the Commission the committee's own report setting forth its observations and conclusions. The Commission is not expecting Duke to simply hire another consultant but to give over the Astrapé Study methodology to this independent review committee and step away, letting the committee perform its review and analysis.

Intervenors will have the opportunity to review and comment on the committee's makeup and report after the report is filed in the 2020 avoided cost proceeding. The Commission is not persuaded that additional involvement of intervenors in the selection of experts for the committee or in the review process is necessary or helpful, but might instead impair the efficiency of the effort and timely review of the Astrapé Study methodology. The request to reconsider its earlier decisions regarding the selection and intervenor participation in the activities of the technical review committee is, therefore, denied.

Seasonal Allocation Weighting

As noted in the April 15 Order the Commission required Duke to address in its initial filings in this proceeding consideration of issues that impact DEC's and DEP's avoided capacity rates, such as the weighting of capacity value between the summer and non-summer seasons. Such information, including the availability of capacity or energy from a QF during the system daily and seasonal peak loads (including dispatchability, reliability, and the individual and aggregate value of energy and capacity from QFs), as well as the relationship of the availability of energy and capacity from the QF to the ability of the utility to avoid costs, is one of a number of factors to be considered in determining avoided costs. April 15 Order at 27.

On April 18, 2019, Duke filed an Agreement and Stipulation of Partial Settlement with the Public Staff pertaining to rate design methodology (Rate Design Stipulation). In the Rate Design Stipulation, Duke and the Public Staff agreed that it is reasonable and appropriate for the

Companies' seasonal and hourly allocations of capacity payments to be based upon the loss of load risk identified in the Astrapé Capacity Value of Solar study, as filed in support of the Companies' 2018 Integrated Resource Plans (IRPs) in Docket No. E-100, Sub 157. The proposed avoided capacity rates recognized that approximately 90% of DEC's loss of load risk occurs in the winter, while approximately 100% of DEP's loss of load risk occurs in the winter.

In its order the Commission found that the proposed avoided energy and avoided capacity rates presented in the Rate Design Stipulation are reasonable and appropriate. *Id.* at 29. The Commission agreed with Duke and the Public Staff that the use of the loss of load risk values to establish seasonal allocation factors is appropriate, as it aligns with cost causation principles. *Id.* at 27. The Commission further stated that these stipulated rates are responsive to the Commission's direction to develop a rate design that sends stronger price signals to incent QFs to better match the generation needs of utilities. *Id.* at 29. The Commission, therefore, concluded that these agreements should be approved as part of acceptance of the Rate Design Stipulation and specifically found that DEC's and DEP's proposed seasonal allocations are appropriate for use in weighting capacity value between winter and summer to calculate DEC's and DEP's avoided capacity rates in this proceeding. *Id.* at 8 (Finding of Fact No. 6).

The Commission also agreed that these factors change over time and that it is appropriate that the resource adequacy studies, along with all inputs and modeling assumptions, should be updated for use in the 2020 biennial IRP filings and taken into account in the 2020 avoided cost proceedings. Thus, as in the last avoided cost proceeding, Docket No. E-100, Sub 148, the Commission stated that it will continue to review these issues in future avoided cost proceedings. *Id.* at 27-28.

On the related issue of the availability of winter demand-side management (DSM) programs, the Commission agreed with Duke witness Snider that significant differences can exist between utilities, including climate, heating sources, industrial demand, and avoided costs, among others, as well as between portfolios of DSM programs targeting providing summer and winter capacity. *Id.* at 28. The Commission found that Duke's assumptions regarding the availability of DSM programs for reducing winter peak demand are reasonable and appropriate for use in calculating avoided capacity rates in this proceeding. *Id.* at 9 (Finding of Fact No. 7). However, as discussed in the 2018 IRP proceeding, Duke should place additional emphasis on defining and implementing cost-effective DSM programs that will be available to respond to winter demands, and the Commission required Duke to address this issue in its initial statements filed in the 2020 biennial avoided cost proceeding. *Id.* at 27.

Motion for Reconsideration

In their Joint Motion NCSEA and NCCEBA note the significant interplay between the studies, models, and assumptions used in the Companies' IRPs and the Companies' determination of avoided cost rates. NCSEA and NCCEBA argue, as they and others did in comments and testimony in this and recent IRP proceedings, that "Duke must improve its assumptions and analysis regarding resource adequacy and seasonal planning, including through the implementation of robust demand side management, energy efficiency, and ancillary services markets to protect from the elusive cold winter morning peak."

In its April 6, 2020 order in the IRP docket, Docket No. E-100, Sub 157, the Commission directed that updated resource adequacy studies be filed along with the Companies' 2020 IRPs, including additional detail and support for both the studies' inputs and outputs. Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans, *2019 Integrated Resource Plan Update Reports and Related 2019 REPS Compliance Plans*, No. E-100, Sub 157, at 12 (N.C.U.C. Apr. 6, 2020) (2019 IRP Order). NCSEA and NCCEBA believe that the Commission should require Duke to make these same filings in the 2020 avoided cost docket to promote efficiency and transparency in the 2020 avoided cost docket and appropriately acknowledge the fundamental overlap between these issues in both the avoided cost and IRP proceedings.

Moreover, although NCSEA and NCCEBA agree with the Commission's statements in this and the IRP proceedings that Duke should place additional emphasis on defining and implementing cost-effective DSM programs that will be available to respond to winter demands, they protest that the April 15 Order "does not require evidence-based solutions or robust transparency to the underlying model, such as the information described in the 2019 IRP Order on resource adequacy studies." NCSEA and NCCEBA express concern "that without this guidance from the Commission, Duke may lack sufficient direction or incentive to conduct a robust analysis of DSM programs that will facilitate the development of meaningful solutions to Duke's infrequent but heavily weighted winter peaking events."

Discussion and Conclusions

The Commission agrees with NCSEA and NCCEBA and has itself emphasized in recent proceedings the significant interplay between the IRP and avoided cost proceedings and the need for consistency between the studies, models, and assumptions used in these proceedings. The Commission's expectation is, as it has been for some time now, that the same models and analyses will be utilized in both the IRP and avoided cost proceedings to achieve this consistency.

In its April 15 Order the Commission again stressed that the studies utilized in the IRP proceeding, particularly the resource adequacy studies required to be updated for the 2020 IRP proceeding, should be taken into account in determining avoided costs in the next proceeding. Although the Commission could simply take judicial notice of the studies filed in the IRP proceeding, to emphasize the importance and relevance of this nexus even further, the Commission will require as requested by NCSEA and NCCEBA that the updated resource adequacy studies, together with any additional detail and support for the study inputs and outputs, be filed in both the 2020 IRP and avoided cost proceedings.

With regard to NCSEA and NCCEBA's concern that the Commission's statements in the April 15 Order that Duke should place additional emphasis on defining and implementing cost-effective DSM programs that will be available to respond to winter demands lack sufficient guidance or direction, the Commission further notes that in the 2020 IRP proceeding, Docket No. E-100, Sub 165, the Commission required Duke to file its 2020 Market Potential Study performed by Nexant. Order Requiring Filing of Report, *2020 Biennial Integrated Resource Plans and Related 2020 REPS Compliance Plans*, No. E-100, Sub 165 (N.C.U.C. June 11, 2020). Duke filed Nexant's energy efficiency and demand-side management market potential studies for Duke

Energy North Carolina and Duke Energy South Carolina with the Commission in the 2020 IRP docket on June 23, 2020. The Commission will require that these studies, as well as the resource adequacy studies, also be filed in the 2020 avoided cost proceeding.

The studies referenced above shall be relevant and admissible in both the 2020 IRP and avoided cost proceedings. To the extent that there is any question about transparency, all such studies shall be subject to full discovery or other review by any other parties in either docket, subject, if applicable, to appropriate nondisclosure agreements.

Capacity Payments for Renewing Qualifying Facilities

With regard to the calculation of avoided cost capacity rates, House Bill 589, Session Law 2017-192 (HB 589), provides that "[a] future capacity need shall only be avoided in a year where the utility's most recent biennial [IRP] has identified a projected capacity need to serve system load and the identified need can be met by the type of small power producer resource based upon its availability and reliability of power," but it expressly carves swine and poultry waste generation out from this requirement based upon their designated need to meet REPS compliance. N.C.G.S. § 62-156(b)(3). Section 3(a) of House Bill 329, Session Law 2019-132 (HB 329), adds to N.C.G.S. § 62-156(b)(3) an additional carve out for "legacy" hydroelectric QFs of 5 MW or less selling and delivering power under QF PPAs in effect as of July 27, 2017. Section 3(b) of HB 329 further provides that "[t]he exception for hydropower small power producers from limitations on capacity payments established in G.S. 62-156(b)(3), as amended by Section 3(a) of this act, shall not be construed in any manner to affect the applicability of G.S. 62-156(b)(3) as it relates to any other small power producer."

In the April 15 Order the Commission found, in interpreting N.C.G.S. § 62-156(b)(3), as amended by HB 329, that only certain QFs — (1) those fueled by swine or poultry waste, or (2) hydroelectric facilities 5 MW or less in capacity that have a power purchase agreement in effect as of July 27, 2017 — which commit to sell and deliver energy and capacity for a new fixed-term contract prior to the termination of the QF's existing contract term are avoiding the Utilities'[1] future capacity need for these designated resource types beginning in the first year following expiration of the QF's existing PPA. For other QFs, it is appropriate for the Utilities to recognize a QF's commitment to sell and deliver energy and capacity over a future fixed term as avoiding an undesignated future capacity need beginning only in the first year when there is an avoidable capacity need identified in DEC's, DEP's, or DENC's most recent IRPs. April 15 Order at 10-11 (Findings of Fact Nos. 23-24).

Motion for Reconsideration

In their Joint Motion NCSEA and NCCEBA seek reconsideration of the Commission's findings regarding the rights of certain QFs to continue to receive full capacity payments upon execution of a subsequent PPA. NCSEA and NCCEBA argue that the Commission misinterpreted the recent amendments to N.C.G.S. § 62-156(b)(3) in limiting this right to swine waste, poultry

[1] In the April 15 Order and in this Order, Dominion Energy North Carolina (DENC) together with DEC and DEP are referred to as the Utilities.

waste, and legacy small hydro facilities. Rather, argue NCSEA and NCCEBA, the amended statutory language mandating that small hydro QFs must be allowed to receive full capacity payments does not preclude the Commission from making a determination that other QF generators with existing PPAs, and which are currently providing capacity to the utility, may continue to receive full capacity payments upon execution of a renewal PPA. Reiterating statements made through testimony and in their post-hearing briefs, NCSEA and NCCEBA believe that it would be highly inefficient, discriminatory, and poor public policy to allow the utility to make arrangements to fill any capacity need created at the expiration of an existing QF contract without first giving that QF the opportunity to continue to serve that capacity need.

Noting that the Commission rejected their previous proposal that existing QFs be given an absolute right to continue being paid for capacity by committing to do so three years before their existing PPAs expire, NCSEA and NCCEBA request that the Commission reconsider its decision on this issue and adopt a different solution to ensure that existing QFs are not discriminated against and, in particular, that utilities not be able to make other arrangements for meeting a capacity need arising due to the expiration of existing PURPA PPAs. NCSEA and NCCEBA state that it would be unfair and inefficient if, prior to the expiration of PURPA PPAs, Duke could say that it is forecasting a capacity need solely for that reason and then build a new gas plant (or other generation) without giving the QFs the opportunity to supply the capacity need being created by the expiration of their PPAs.

NCSEA and NCCEBA request that the Commission modify the order to require that each time Duke or DENC identifies a future capacity need based upon expiring QF PPAs, those QFs with expiring PPAs be given an opportunity to commit to supplying that need, without priority right to do so relative to new QFs. NCSEA and NCCEBA recognize that allowing any sort of guarantee to an existing QF may be unfair and prejudicial against new QFs, and they further request that the Commission order Duke, DENC, and the Public Staff to work with them and other intervenors to develop a preferred process for allocating limited capacity rights among QFs.

Discussion and Conclusions

As NCSEA and NCCEBA acknowledge, and as demonstrated in the Commission's discussion in the April 15 Order, this issue was fully litigated in this proceeding and addressed through the testimony of multiple parties' witnesses, including their own, and in post-hearing briefs.

House Bill 589 amended N.C.G.S. § 62-156(b)(3) in 2017 to provide:

> A future capacity need shall only be avoided in a year where the utility's most recent biennial integrated resource plan filed with the Commission pursuant to G.S. 62-110.1(c) has identified a projected capacity need to serve system load and the identified need can be met by the type of small power producer resource based upon its availability and reliability of power, other than swine or poultry waste for which a need is established consistent with G.S. 62-133.8(e) and (f).

House Bill 329 amended N.C.G.S. § 62-156(b)(3) in 2019 to add an exception for "hydropower small power producers with power purchase agreements with an electric public utility in effect as of July 27, 2017, and the renewal of such a power purchase agreement, if the hydroelectric small power producer's facility total capacity is equal to or less than five megawatts (MW)." Thus, the amendments to N.C.G.S. § 62-156(b)(3) enacted by HB 589 and HB 329 provide that facilities utilizing swine or poultry waste and certain small hydro facilities always receive a capacity credit, even when a utility's most recent IRP has not identified a projected capacity need; all other facilities only avoid future capacity needs and receive capacity payments when a utility's most recent IRP has identified a projected capacity need.

All parties agree that the expiration of a wholesale contract can affect the timing of a utility's first capacity need. In making this determination, Duke witness Snider stated that Duke has assumed in its IRPs that upon expiration of any third-party wholesale purchase contract, capacity is reduced by the amount of the capacity provided by the expiring wholesale purchase contract in the year following contract expiration. He further stated that 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. He pointed out that there is no guarantee for Duke and its customers that a QF will be able to provide energy and capacity after expiration of the PPA, as QF owners have the right at the end of a contract to make their unrestricted decision as whether to renew their PPAs, cease business, or sell their energy and capacity to another buyer. In response to NCSEA witness Johnson's claim that Duke's approach to contract renewals is discriminatory, witness Snider contended that, actually, witness Johnson's approach was discriminatory in that it would favor existing QFs over new capacity resources, including new QFs.

Public Staff witness Hinton reviewed Duke's assumptions regarding expiring PPAs, and he stated that Duke uses the same assumptions for all wholesale contracts — i.e., that the contracts would expire and the capacity would no longer be available — in establishing its first year of capacity need for avoided cost purposes. The Public Staff stated that Duke's IRPs indicate a reduction in capacity from expiring biomass and hydro PPAs in the planning period, which effectively decreases each utility's available capacity and increases the need for undesignated future resources, but that the IRPs assume an increase in capacity from solar facilities. Witness Hinton stated that while this assumed increase in capacity regarding solar PPAs may be appropriate for planning purposes, it is inappropriate for determining the first year of capacity need as it could elongate the time before there is a capacity need. Public Staff witness Hinton disagreed with NCSEA that the Utilities should assume that all QF contracts renew and that existing QFs should be entitled to a capacity payment beginning in the first years of their new contract term. The Public Staff pointed out that this issue would have no impact on avoided capacity rates in this proceeding but would become more and more important in future years.

The Commission adopted the Public Staff's recommendation that the utilities file a formal Statement of Need in future IRP proceedings. The Commission agreed with Duke and the Public Staff that QFs commit to deliver their power for a specified term and that it would be imprudent resource planning to assume that QFs are obligating themselves to deliver capacity and energy past the end of their contract term. The Commission further agreed that it would be discriminatory between QFs to assume that a pre-existing QF has a priority right to enter into a new contract to sell and deliver capacity over a new term versus the rights of any other QF to commit itself to avoid the utility's capacity need. The Commission concluded that for types of QF generation which do not meet a designated capacity need specified by the General Assembly, it is appropriate for QFs electing to obligate themselves to deliver power for a new contract term to be considered as avoiding undesignated new generation projected to be needed in the future to serve the utility's system load.

The Commission fully considered all the evidence and arguments presented by the parties on this issue, and NCSEA and NCCEBA have provided no new evidence, arguments, or other basis upon which to overturn the Commission's decision on reconsideration.

Material Alterations

In its Joint Initial Statement Duke amended its Schedule PP PPA and Terms and Conditions to provide that any material modification to a QF, including the addition of batteries or other technologies for the storage and later injection of energy, without Duke's consent would constitute an event of default resulting in termination of the PPA at Duke's election. Further, Duke proposed amendments to Section 1.4 of the Schedule PP PPA and Section 4 of the Terms and Conditions to clarify that modifying a QF to increase the AC energy output or the delivered DC capacity of the facility would be an event of default.

In response to objections by the Public Staff and other intervenors, in its March 27, 2019 Reply Comments Duke proposed to modify Section 4 of its amended Terms and Conditions to refer to a new defined term, "Material Alteration," to more clearly define what constitutes a material change to a QF. The new definition of Material Alteration provided in Section 3(f) is as follows:

> "Material Alteration" as used in this Agreement shall mean a modification to the Facility which renders the Facility description specified in this Agreement inaccurate in any material sense as determined by Company in a commercially reasonable manner including, without limitation, (i) the addition of a Storage Resource; (ii) a modification which results in an increase to the Contract Capacity, Nameplate Capacity (in AC or DC), generating capacity (or similar term used in the Agreement) or the estimated annual energy production of the Facility (the "Existing Capacity"), or (iii) a modification which results in a decrease to the Existing Capacity by more than five (5) percent. Notwithstanding the foregoing, the repair or replacement of equipment at the Facility (including solar panels) with like-kind equipment, which does not increase Existing Capacity or decrease the Existing Capacity by more than five percent (5%), shall not be considered a Material Alteration.

In the April 15 Order the Commission approved Duke's proposed modifications to the Standard Terms and Conditions, April 15 Order at 136 (Ordering Paragraph No. 30), and made the following findings of fact:

> 49. The proposed modifications to the Standard Terms and Conditions proposed by Duke, including the definition of Material Alteration, are reasonable and appropriate. In determining whether updates to a facility are a Material Alteration that would lead to the termination of the existing PPA, Duke should evaluate those changes in a commercially reasonable manner and with a "degree of reasonableness" regarding any increase in capacity that results from equipment replacement and repairs.
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> 50. Prior to increasing their output consistent with the Terms and Conditions of their existing PPAs, "Committed" solar QFs (i.e., facilities that have (i) established a legally enforceable obligation (LEO); (ii) executed a PPA; or (iii) commenced operation and sale of the electric output of the facility) that seek to add storage or otherwise materially increase their output by re-paneling or over-paneling should obtain the utility's consent, contingent on an evaluation of the potential impacts to the utility's system or other customers.
>
> 51. Material alterations to committed facilities that increase a utility's obligations to purchase energy at prior avoided cost rates are inappropriate and would unfairly burden ratepayers with increased payments to QFs that exceed current avoided cost rates. However, it is premature at this time to determine whether the Public Staff's compromise position that existing solar facilities that add storage by co-locating a battery behind the meter should be compensated at the current avoided cost rates is appropriate.
>
> 52. It is appropriate for the parties to continue to discuss the technical, regulatory, and contractual complexities of separately metering the energy output from energy storage equipment that is co-located at existing solar facilities for further consideration by the Commission.

April 15 Order at 13-14 (Findings of Fact Nos. 49-52).

Motion for Reconsideration

In their Joint Motion NCSEA and NCCEBA seek reconsideration of a number of issues related to the new provision on Material Alteration. First, NCSEA and NCCEBA object to the retroactive application of the new Material Alteration provision to existing standard offer contracts. NCSEA and NCCEBA state that the April 15 Order ignores the fact that contracts are binding legal documents that must be interpreted based on what they actually say, not on what Duke or the Commission believes they should say. NCSEA and NCCEBA argue, after detailing a comprehensive review of previous standard offer contracts, that the documents that comprise the Sub 136 and Sub 140 PPAs do not, under any reasonable interpretation, impose the limitations on QFs that Duke requested and that the Commission has agreed to make to Duke's form PPA and

Terms and Conditions going forward. NCSEA and NCCEBA further argue that these modifications, if applied to existing contracts, constitute major substantive changes to the rights and obligations of Duke and QFs relative to the terms of prior standard offer contract documents and that the Commission should reconsider its decision to impose these new and altered terms on QFs retroactively.

NCSEA and NCCEBA next object to the inclusion of a reduction in capacity of more than 5% as a Material Alteration, especially given Duke's repeated complaints about the proliferation of solar QF generation. NCSEA and NCCEBA state that this limitation effectively amounts to a minimum sizing of the QF and note that the Commission has never previously deemed this to be appropriate.

NCSEA and NCCEBA further note the terms and conditions allow replacements with "like-kind" equipment but lack a definition of "like-kind" or any guidance as to how it is to be interpreted. NCSEA and NCCEBA request that the Commission modify the April 15 Order to define the term "like-kind" to mean "any equipment of the same general nature, and being used for the same general purpose, as the original equipment."

NCSEA and NCCEBA further question why a QF should require Duke's approval to add a battery storage device where there is no increase in the output of the facility. NCSEA and NCCEBA argue that there is no risk of ratepayers having to pay for additional energy at a higher, outdated avoided cost rate. To the extent that the battery allows for shifting of delivery from one time period to another, NCSEA and NCCEBA state that Duke witness Snider asserted that ratepayers are indifferent to this result. Accordingly, NCSEA and NCCEBA request the Commission reconsider its decision and find that added battery storage with no increase in energy output of the facility does not require utility approval.

NCSEA and NCCEBA additionally protest that the Commission has provided no guidance as to what would constitute reasonable grounds for the utility to deny a request for a Material Alteration. NCSEA and NCCEBA cite an apparent concern regarding the payment of old, higher rates as a result of a Material Alteration, and they request that the Commission direct Duke to address this issue in the ongoing storage retrofit stakeholder process required by the Commission and that such issue discussion also include a discussion about increased output from other types of material alterations, including repaneling.

Lastly, NCSEA and NCCEBA note, as provided in Finding of Fact No. 49 of the April 15 Order, that any changes to existing facilities will be evaluated in a commercially reasonable manner. However, in Duke's compliance filing, Section 4(e) of the Terms and Conditions state that Duke may decline to approve a Material Alteration in "its sole discretion." This provision in the compliance filing is inconsistent with Duke's representations and the Commission's order and should be changed.

Discussion and Conclusions

Changes to existing contracts

Like NCSEA and NCCEBA, the Commission also reviewed the terms and conditions of prior avoided cost PPAs as well as the comments, testimony, exhibits, and briefs filed in this proceeding in reaching its decisions in the April 15 Order. The Commission, however, disagrees with NCSEA and NCCEBA; the April 15 Order does not improperly modify existing Standard Offer PPAs to include the provision on Material Alterations and limit a QF's ability to add battery storage to an existing facility.

As NCSEA and NCCEBA note, in the 2012 avoided cost proceeding, Docket No. E-100, Sub 136, DEP filed a rate tariff — Cogeneration and Small Power Producer Schedule CSP-29 — which incorporates specific energy and capacity credits for various contract terms, an Application for Standard Contract by a Qualifying Cogenerator or Small Power Producer, and Terms and Conditions for the Purchase of Electric Power. In the Application, which when accepted by DEP becomes an Agreement to purchase from the "qualifying generating facility" described therein, the owner of the QF requests that DEP purchase its output in accordance with the rate tariff and the Terms and Conditions, "a copy of each being attached and made a part of this Agreement." The Terms and Conditions "provide a mechanism through which [DEP] will agree to purchase energy or capacity or both from an Eligible Qualifying Facility as defined in Company's CSP Rate Schedule." Section 1(c) of the Terms and Conditions specifically provides:

> <u>Application of Terms and Conditions, Schedules, and Riders</u> — All Purchase Agreements in effect at the time of the approval hereof or that may be entered into in the future, are made expressly subject to these Terms and Conditions, and subject to all applicable Schedules and Riders, and any changes therein, substitutions thereof, or additions thereto lawfully made, provided no change may be made in rates or in essential terms and conditions of this contract except by agreement of the parties to this contract or by order of the North Carolina Utilities Commission.

As NCSEA and NCCEBA further note, DEC's filing in the Sub 136 avoided cost proceeding did not include a separate Terms and Conditions, but did include a rate tariff — Schedule PP-H (NC) Hydroelectric Qualifying Facilities Purchased Power or Schedule PP-N (NC) Non-Hydroelectric Qualifying Facilities Purchased Power — and a Purchased Power Agreement. The Agreement, like DEP's, obligates DEC to purchase the electric power generated by the QF. Section 2 of the Agreement provides:

> <u>Rate Schedule and Service Regulations</u>. The sale, delivery, and use of electric power hereunder, and all services of whatever type to be rendered or performed in connection therewith, shall in all respects be subject to and in accordance with all the terms and conditions of the Company's Rate Schedule [PP-H][PP-N], Electricity No. 4, North Carolina Revised Leaf No. [91][92], [Variable Rate][5-year Fixed Long-Term Rate], [10-year Fixed Long-Term Rate] [15-year Fixed Long-Term Rate] Option [A][B] for [Distribution][Transmission] Interconnection ("Rate Schedule") and its Service Regulations, both of which are now on file with

the North Carolina Utilities Commission ("Commission"), and are hereby incorporated by reference and made a part hereof as though fully set forth herein. Said Rate Schedule and Service Regulations are subject to change, revision, alteration or substitution, either in whole or in part, upon order of said Commission or any other regulatory authority having jurisdiction, and any such change, revision, alteration or substitution shall immediately be made a part hereof as though fully written herein, and shall nullify any prior provision in conflict therewith.

In the next avoided cost proceeding, Docket No. E-100, Sub 140, DEC and DEP adopted more similar documents, with each filing a rate tariff, a Purchase Power Agreement, and Terms and Conditions for the Purchase of Electric Power. Section 1(b) of DEC's and DEP's Terms and Conditions filed in the Sub 140 docket are substantially identical to Section 1(c) of DEP's Sub 136 Terms and Conditions, and Section 2 of the Purchase Power Agreement is substantially identical to Section 2 of DEC's Purchased Power Agreement except that it includes a reference to the Terms and Conditions rather than the Service Regulations. This model has been consistently used by DEC and DEP in subsequent avoided cost proceedings, including this proceeding, Sub 158.

A proper reading of each of these contracts provides that the terms and conditions of the contract, other than the specific rates, "are subject to change, revision, alteration or substitution, either in whole or in part, upon order of [the] Commission . . ., and any such change, revision, alteration or substitution shall immediately be made a part hereof as though fully written herein, and shall nullify any prior provision in conflict therewith." For DEC, the initial change was one approved in the rate tariff; for DEP and subsequent DEC tariffs, the change was in the Terms and Conditions. Here, the Commission approved an amendment to the Terms and Conditions to add the provision regarding Material Alterations. This amendment to the Terms and Conditions does not "interpret the existing PPA terms and conditions in a manner different than their strict contractual language" and does not violate a QF's right to sell energy and capacity under an existing PPA as the facility was described at the time the agreement was entered into and at the rates set forth in that agreement. Thus, not only are such changes consistent with the language of prior agreements, they were contemplated and specifically included in the contract language. Parties are on notice and presumably aware upon entering the agreement that certain terms and conditions are subject to change by the Commission. The Commission, therefore, denies reconsideration on this issue and affirms its finding that the modifications to the Standard Terms and Conditions proposed by Duke, including the definition of Material Alteration, are reasonable and appropriate

A QF cannot demand strict compliance with the agreement with a modified facility. NCSEA and NCCEBA's analysis of previously approved Standard Offer PPAs erroneously focuses on "estimated annual energy production" and not on changes that would increase the capacity of the facility. In describing the Sub 140 Terms and Conditions, NCSEA and NCCEBA quote the modification that "[t]he Seller shall not change its generating capacity . . . without receiving the Company's consent," but then allege that "[t]he Sub 140 Terms and Conditions do not prohibit or require DEC/DEP approval of changes to the Facility's DC rating, changes in the time of delivery, or equipment modifications."

A Material Alteration to a facility should result in a review of payments under the existing contract. The Commission agreed that allowing a QF to modify its facility to substantially increase energy output and be compensated at prior avoided cost rates would result in significant overpayment beyond the current avoided cost, which would be unfair to ratepayers. The Commission did not adopt the compromise position proposed by the Public Staff for bifurcated avoided cost rates, but the Commission did find it appropriate to continue to investigate the proposed compromise as a potential solution to properly encourage the addition of battery storage in a manner that is fair to ratepayers.

Reduction of capacity

As discussed above, a Material Alteration includes any deviation from the description of the facility in the original PPA. A decrease in capacity may have operational or planning impacts on the utility the same as capacity increases. NCSEA and NCCEBA have provided no new evidence, arguments, or other basis upon which to overturn the Commission's decision on reconsideration. The Commission, therefore, affirms its prior finding that Duke's proposed definition of Material Alteration, including a modification which results in an increase in the estimated annual energy production of the QF (Existing Capacity) or a decrease by more than five percent is appropriate and denies reconsideration on this issue.

Definition of "like-kind"

The Commission stated in the April 15 Order that the owner of a QF should be allowed to maintain the facility during the term of the contract, including repair and replacement of parts and equipment. The definition of Material Alteration specifically provides that "the repair or replacement of equipment at the Facility (including solar panels) with like-kind equipment, which does not increase Existing Capacity or decrease the Existing Capacity by more than five percent (5%), shall not be considered a Material Alteration." The Commission concluded that this language in the definition of "Material Alteration," which expressly allows replacement of "like-kind" equipment and provides that Material Alterations will be evaluated in a "commercially reasonable manner," adequately addressed NCSEA and NCCEBA's concerns.

While the Commission agrees that the term "like-kind" may include "any equipment of the same general nature, and being used for the same general purpose, as the original equipment," to define "like-kind" as such appears unnecessary and may actually limit its application as it is impossible to anticipate every scenario that might be encompassed within a "like-kind" replacement. NCSEA and NCCEBA ask, for example, whether a mono-facial solar PV panel may be replaced with a bi-facial panel of the sort commonly being use today. As stated in the definition of Material Alteration, the answer turns on whether the repaneling changes the Existing Capacity. Duke shall act in a commercially reasonable manner regarding Material Alterations and does not have unfettered discretion in determining whether a replacement is with like-kind equipment, and any aggrieved party who believes the utility improperly applied the term "like-kind" may file a complaint with the Commission.

The Commission, therefore, is not persuaded that it is appropriate to adopt a specific definition of like-kind for the purpose of interpreting the Material Alteration provision added to DEC's and DEP's Terms and Conditions and denies reconsideration on this issue.

Addition of battery with no increase in output

NCSEA and NCCEBA base their argument on this issue on testimony by Duke witness Snider which they believe indicates that ratepayers are indifferent to the extent that a battery allows for shifting of delivery from one time period to another. Upon review of witness Snider's testimony, the Commission does not agree with NCSEA and NCCEBA's interpretation. His testimony assumes different pricing during different delivery hours, and he states that ratepayers are indifferent to whether the utility purchases energy at avoided cost rates or generates the energy itself. The testimony cited by NCSEA and NCCEBA does not address potential changes in the delivery of energy under existing PPAs made possible by the addition of storage, even where the capacity is not increased, which may result in additional costs to ratepayers. In other testimony Duke witness Snider clearly states that such time-shifting would be detrimental to ratepayers. In his Supplemental Testimony, for example, Duke witness Snider states:

> For example, the addition of battery storage to an existing QF that has committed to sell under the legacy "Option B" avoided cost rate design would allow the QF to generate/discharge more power during legacy "on-peak" periods that no longer align with the Companies' highest marginal cost hours. In other words, absent the QF entering into a modified or new PPA reflecting Duke's current avoided costs and rate design, the addition of a battery storage system to an existing QF obligates the Companies, and thus their customers, to pay the QF for new and additional output in certain hours at rates exceeding the utility's now-current avoided costs, in a manner that was not contemplated by either the QF or the interconnecting utility at the time the QF originally committed to sell its output.

Tr. vol. 2, 166.

While finding that it was premature to decide whether the Public Staff's hybrid rate proposal is appropriate, the Commission found that it is appropriate to continue to investigate the proposed compromise as a potential solution to properly encourage the addition of battery storage in a manner that is fair to ratepayers. The Commission directed stakeholders to virtually meet and consider issues related to the addition of battery storage, including specific technology, commercial, and regulatory issues, and then to report to the Commission on the results of the stakeholder process.

As stated above, a Material Alteration specifically includes the addition of a Storage Resource even where there is no increase in the total energy output of the QF. The Commission found in the April 15 Order that Duke's proposed modifications to the Standard Terms and Conditions, including the definition of Material Alteration, are reasonable and appropriate and finds here that NCSEA and NCCEBA have provided no new evidence, arguments, or other basis upon which to overturn the Commission's decision on reconsideration.

Issues to be discussed in stakeholder process

As noted above, the Commission specifically directed Duke to virtually convene a stakeholder group to consider the various technical, commercial, and regulatory challenges associated with the addition of battery storage at an existing facility. The Commission further required Duke and DENC to report to the Commission on the results of the process by September 1, 2020. The question of other Material Alterations that increase the output of a facility, such as repaneling, also raise the issue of how to compensate the QF for the increased output; however, this issue is beyond the scope of the initial stakeholder discussions and should not be taken up at this time. It is possible that such discussions may be taken up at a later time, but the Commission's focus, as expressed in the April 15 Order, and its directions to the stakeholder group are upon barriers to the addition of battery storage. The stakeholder group has already convened and held several meetings on the issues before it, and the Commission is not persuaded that additional issues should be put before the stakeholder group at this time.

Compliance filing: "In its sole discretion"

As directed by the Commission, Duke made a compliance filing on November 1, 2019, in response to the October 7, 2019 Notice of Decision and October 17, 2019 Supplemental Notice of Decision issued by the Commission in this proceeding. In response to the April 15 Order, Duke made a further compliance filing stating that the filings submitted on November 1, 2019, "accurately reflect the conclusions reached" in the Commission's April 15 Order. No party objected to Duke's November 1, 2019 compliance filing, and no party objected to its May 15, 2020 compliance filing.

In its March 27, 2019 Reply Comments and its November 1, 2019 compliance filing, Duke includes the following language related to Material Alteration:

3. <u>DEFINITIONS</u>

(f) "Material Alteration" as used in this Agreement shall mean a modification to the Facility which renders the Facility description specified in this Agreement inaccurate in any material sense as determined by Company in a commercially reasonable manner including, without limitation, (i) the addition of a Storage Resource; (ii) a modification which results in an increase to the Contract Capacity, Nameplate Capacity (in AC or DC), generating capacity (or similar term used in the Agreement) or the estimated annual energy production of the Facility (the "Existing Capacity"), or (iii) a modification which results in a decrease to the Existing Capacity by more than five (5) percent. Notwithstanding the foregoing, the repair or replacement of equipment at the Facility (including solar panels) with like-kind equipment, which does not increase Existing Capacity or decrease the Existing Capacity by more than five percent (5%) shall not be considered a Material Alteration.

4. CONTRACT CAPACITY

(e) Any Material Alteration to the Facility, including without limitation, an increase in the Existing Capacity, a decrease in the Existing Capacity by more than five (5) percent or the addition of energy storage capability shall require the prior written consent of the Company, which may be withheld in the Company's sole discretion, and shall not be effective until memorialized in an amendment executed by the Company and the Seller.

Thus, while the definition in Section 3 provides that Duke will determine whether a change is a Material Alteration "in a commercially reasonable manner," Section 4 allows Duke to withhold consent for the Material Alteration "in its sole discretion."

This distinction was made in testimony at the hearing. Upon cross-examination by counsel for SACE, Public Staff witness Metz was asked about this apparent discrepancy and explained that commercial reasonableness is provided in the definition of Material Alteration, or the determination of whether a change is a Material Alteration, but the decision whether to approve the change is left to the utility and its determination of system impact as the operator of the electric grid. Tr. vol. 7, 23-25, 27-28. Similar testimony was elicited on further cross-examination of witness Metz by counsel for Duke. Tr. vol. 7, 84-86.

NCSEA and NCCEBA raise this issue as simply a change that was overlooked by Duke in making its compliance filing — a matter that should have been raised at the time the initial compliance filing was made including that language on November 1, 2019. However, this was not merely an oversight, as this issue was raised at the hearing on cross-examination of Public Staff witness Metz. It is clear — and Duke conceded as such — that the determination of whether a change is a Material Alteration is to be made in a commercially reasonable manner, and that is embodied in the definition of Material Alteration in Section 3 of the Terms and Conditions. The decision whether to allow the Material Alteration is within Duke's sole discretion as the electric grid operator. Again, any aggrieved party may file a complaint with the Commission.

The Commission, therefore, concludes that it fully considered all of the evidence and arguments presented by the parties on this issue, and NCSEA and NCCEBA have provided no new evidence, arguments, or other basis upon which to overturn the Commission's decision on reconsideration.

CONCLUSION

After careful consideration, the Commission finds good cause to deny NCSEA and NCCEBA's motion for reconsideration. As provided herein, however, the Commission will require Duke to file its resource adequacy studies, together with any additional detail and support for the study inputs and outputs, and the Nexant energy efficiency and demand-side management market potential studies in both the 2020 IRP and avoided cost proceedings.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of July, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

Commissioners Kimberly W. Duffley, Jeffrey A. Hughes, and Floyd B. McKissick, Jr., did not participate.

DOCKET NO. E-100, SUB 163

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
2019 REPS Compliance Plans and	)	ORDER APPROVING 2018 REPS
2018 REPS Compliance Reports	)	COMPLIANCE REPORTS AND
	)	ACCEPTING 2019 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. Subsection 62-133.8(c) sets out the perecntage 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 28 and November 1, 2019, the following municipal electric power suppliers, electric membership corporations, and utility compliance aggregators filed their 2018 REPS compliance reports and 2019 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; NTE Carolinas, LLC (NTE), on behalf of the Town of Black Creek, the Town of Lucama, the Town of Sharpsburg, the Town of Stantonsburg, and the Town of Winterville (NC Towns); and the North Carolina Electric Membership Corporation (NCEMC), on behalf of its member cooperatives and four other electric power suppliers.[1]

On December 3, 2019, NTE filed an updated 2018 REPS compliance report.

On April 17, 2020, FPWC filed an updated 2018 REPS compliance report.

On April 23, 2020, the Public Staff filed comments addressing the following: the 2018 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 2019 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 2018

[1] In its 2018 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. Beginning with the 2018 REPS compliance year, Halifax EMC has joined NCEMC's REPS compliance members and is included in NCEMC's plan. The Town of Enfield is a wholesale customer of Halifax EMC, and Enfield's REPS requirements are included as part of Halifax EMC's REPS requirements.

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 2018 REPS compliance reports filed by EnergyUnited, FPWC, NCEMC, NCEMPA, NCMPA1, NTE, 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, with exception of the swine and poultry waste set-aside.

NCEMC filed reply comments on April 29, 2020.

REPS REQUIREMENTS FOR EMCS AND MUNICIPALITIES

For 2018, 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 ten percent of its 2017 retail sales by using renewable energy or by reducing energy consumption through implementation of DSM or EE measures. Within this ten 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 2018 REPS compliance reports and 2019 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 2018, the solar set-aside requirements provide that each EMC and municipality shall supply 0.2 percent of its 2017 retail sales through the use of solar energy resources. Pursuant to the authority granted to the Commission in N.C.G.S. § 62-133.8(i)(2), the 2018 swine and poultry waste set-aside requirements were modified 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. On December 16, 2019, the Commission issued a further order in Docket No. E-100, Sub 113 (2019 Delay Order), which 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 to 300,000 MWh and delaying the scheduled increases by one year, as well as reducing the scheduled increase in 2019 to 500,000 MWh.

In its comments, the Public Staff states that all of the EMCs and municipalities met the solar set-aside requirements. The Public Staff notes the swine waste requirement continues to be difficult for the electric power suppliers to achieve in the near future. However, only FPWC, NCEMC, and Waynesville (representing around 48% of total 2018 sales for the Muni/EMC Suppliers) expressed doubt as to their ability to meet the poultry waste set-aside for 2019.

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

Subsections 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 2018, 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 2018. The Public Staff summarizes REPS compliance and compliance costs for 2018 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 2021.

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

Subsection 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 REPS 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 REPS compliance reports and REPS 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, and NCEMC 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.

The Public Staff notes that after enactment of the Energy Independence and Security Act (EISA) in December 2007, the U.S. Department of Energy (DOE) adopted revised energy conservation standards for general service light bulbs. This increased efficiency standard would have become effective on January 1, 2020; however, the DOE withdrew the revised lighting standards before they could become effective finding that they were not economically justified.

The Public Staff then discusses the rapid transformation of the EE lighting market and states that the EE lighting market in North Carolina appears to be transforming at a faster rate than was initially recognized. The Public Staff credits this fast transformation to changes to federal lighting standards since 2007 and to customer preference for LED lighting. The Public Staff asserts that the lighting market has substantially transformed to the point that non-specialty LED lighting should be considered the baseline standard for general service bulb technologies. Therefore, as in prior dockets, 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 only the specialty LED bulb technologies should qualify, and should be reflected in future EMC and municipality REPS compliance plans, starting with the upcoming filing due September 1, 2020.

NCEMC filed reply comments on April 29, 2020, objecting to the Public Staff's recommendations that only specialty LED bulb technologies should qualify as a means for generating EECs for REPS compliance after 2020. NCEMC argues that LED bulb technologies are not yet the baseline, noting the DOE's change of position and determination not to implement revised energy conservation standards beginning in January of 2020. NCEMC states that the DOE's final determination is a significant change of circumstances that should be noted by the Commission as a strong indication that the federal government does not recognize that a "market transformation" from CFLs as baseline to LEDs as baseline has as of yet, not occurred.

NCEMC also notes that the Public Staff raises as one of the goals of EE programs raising "customer awareness of and confidence in EE technologies, and to encourage customers to adopt EE measures on their own." While the Public Staff indicates that North Carolina has reached that point, NCEMC provided examples of its members' recent social media efforts to continue to build customer awareness and confidence in LEDs stating that such efforts by its members calls "into question whether LED adoption has truly become 'routine' and 'baseline' in the service areas of NCEMC's REPS Compliance Members."

In Docket No. E-100 Sub 159, in its Order Approving 2017 REPS Compliance Reports and Accepting 2018 REPS Compliance Plans issued on August 13, 2019, the Commission found that it would allow electric suppliers to address whether EECs from lighting measures should be required to address, in their M&V study process, whether a new baseline for lighting-based EE programs is appropriate "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." The Public Staff determined that the M&V study process presented by the three electric suppliers claiming EECs were satisfactory. NCEMC indicates that its plan to update its M&V study during the 2021-2022 timeframe has not changed, especially in light of the DOE's withdrawal of its revised lighting standards, its desire to keep administrative costs down, and the current COVID crisis' negative impact on electric cooperative finances.

The Commission appreciates the Public Staff's attention to the EEC's M&V 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. For this reason, in the August 13, 2019 order approving the 2017 REPS compliance reports, the Commission provided the EMCs and municipalities an additional year to review and adjust to the new requirements. However, based on the current negative economic impact facing the EMCs and municipalities as a result of the COVID pandemic, the decision by the DOE not to adopt revised lighting standards, and the satisfactory M&V support provided by the three electric suppliers that included EEC programs in their 2018 REPS compliance reports, the Commission finds that it will delay adopting the Public Staff recommendation regarding M&V process study requirements for support of EEC lighting measures for one additional year. Therefore, the Commission will adopt the Public Staff recommendation effective for the REPS compliance filings due to be filed on September 1, 2021. Additionally, the Commission finds that based on the DOE's decision to withdraw its revised lighting standards, the Commission will not adopt the Public Staff's recommendation that non-specialty LED lighting should be considered the baseline standard for general service light bulb technologies at this time, declining to adopt LED as the baseline at this time. Finally, the Commission finds the Public Staff's comments on these issues quite helpful and directs the Public Staff to 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.

2018 REPS COMPLIANCE REPORTS

Each EMC and municipality (or its utility compliance aggregator) required to do so filed in this docket the 2018 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 2018 general REPS requirements of N.C.G.S. § 62-133.8(c) and the 2018 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 2018 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 2018 REPS obligations and reporting requirements, the Commission reviewed and considered the 2018 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 28, 2019, EnergyUnited filed its 2018 REPS compliance report. EnergyUnited's report demonstrates that EnergyUnited's 2017 total retail sales were 2,517,130 MWh; therefore, EnergyUnited's general REPS obligation of ten percent of 2017 retail sales is 251,173 RECs, and its solar set-aside requirement, based on 0.2 percent of 2017 sales, is 5035 RECs. Further, EnergyUnited's share of the 2018 poultry waste requirement is 5,473 poultry waste RECs. EnergyUnited's 2018 REPS compliance sub-account in NC-RETS demonstrates that EnergyUnited met its 2018 REPS requirements by submitting the required number of RECs for retirement based upon the foregoing sales levels and REPS requirements.

In its April 23 comments, the Public Staff states that EnergyUnited's Report and its NC-RETS-account indicate that it met its REPS requirements for 2018. The Public Staff notes that EnergyUnited included EECs from two programs, the Commercial Lighting Program and the Heat Pump Rebate Program and supported the number of EECs generated by these programs through the use of a 2009-11 Bellwether Management M&V report and an Energy Star savings calculator, which the Public Staff found acceptable. The Public Staff also notes that EnergyUnited has updated the calculations to reflect the most current applicable standards and recommend the Commission approve EnergyUnited's 2018 REPS Compliance Report.

Based upon the foregoing and the entire record in this proceeding, including EnergyUnited's 2018 REPS compliance report, the data in EnergyUnited's 2018 REPS compliance sub-account in NC-RETS, and the comments of the Public Staff, the Commission finds that EnergyUnited complied with its 2018 REPS requirements, and that the RECs and EECs in EnergyUnited's 2018 REPS 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 2018 REPS compliance report should be approved.

FPWC

On August 30, 2019, FPWC filed its 2018 REPS compliance report. On April 17, 2020 FPWC filed a revised 2018 REPS compliance report correcting some typographical errors. FPWC's report indicates that FPWC's 2017 total retail sales were 1,967,324 MWh; therefore, FPWC's general REPS obligation of ten percent of 2017 retail sales is 196,733 RECs, and its solar set-aside requirement, based on 0.2 percent of 2017 sales, is 3,935 solar RECs. Further, FPWC's share of the 2018 poultry waste requirement is 4,668 poultry waste RECs. FPWC's 2018 REPS compliance sub-account in NC-RETS demonstrates that FPWC met its 2018 REPS requirements by submitting the required number of RECs for retirement based upon the foregoing sales levels and REPS requirements.

The Public Staff states that FPWC's Report and its NC-RETS sub-account indicate that it met its REPS requirements for 2018. The Public Staff noted that FPWC did not use any EECs for REPS compliance in 2018 but has the following four EE programs that generate EECs: (1) Refrigerator Incentive Program (RIP), (2) Residential Heating, Ventilation, and Air Conditioning (HVAC) Program, (3) Energy Efficient Lamp Distribution Program, and (4) Light Emitting Diode (LED) Street Light Program. The Public Staff stated that FPWC has performed EM&V and banked EECs for the LED Street Lighting Program and the Residential HVAC Program. For EM&V, FPWC used data from version 8 of the 2018 Mid-Atlantic Technical Reference Manual 8 (Mid-Atlantic TRM), which the Public Staff states that it finds acceptable. Finally, the Public Staff recommends that the Commission approve FPWC's 2018 REPS compliance report.

Based on the foregoing and the entire record herein, the Commission finds that FPWC has complied with its 2018 REPS requirements, and that the RECs and EECs in FPWC's 2018 REPS compliance sub-account in NC-RETS should be retired. The Commission further finds that FPWC's 2018 REPS compliance report includes the information and supporting documentation required by Commission Rule R8-67(c), and, therefore, the Commission concludes that FPWC's 2018 REPS compliance report should be approved.

NTE

On November 1, 2019, NTE filed its 2018 REPS compliance report. Subsequently, on December 3, 2019, NTE filed a supplemental 2018 REPS compliance report, containing completed information on total incremental costs incurred during the calendar year. NTE's report indicates that NTE's 2017 total retail sales were 113,374 MWh; therefore, NTE's general REPS obligation of ten percent of 2017 retail sales is 11,338 RECs, and its solar set-aside requirement, based on 0.2 percent of 2017 sales, is 277 solar RECs. Further, NTE's share of the 2018 poultry waste requirement is 266 poultry waste RECs. NTE's 2018 REPS compliance sub-account in NC-RETS demonstrates that NTE met its 2018 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 NTE's Report and its 2018 NC-RETS sub-account indicate that it met the REPS requirements for 2018. The Public Staff notes that NTE did not use EECs for REPS compliance in 2018. Further, the Public Staff recommended approval of NTE's 2018 REPS compliance report.

Based upon the foregoing and the entire record in this proceeding, including NTE's 2018 REPS compliance report, the data in NTE's 2018 REPS compliance sub-account in NC-RETS, and the comments of the Public Staff, the Commission determines that NTE complied with its 2018 REPS requirements, and that the RECs and EECs in NTE's 2018 REPS compliance sub-account in NC-RETS should be retired. Further, the Commission finds that NTE's 2018 REPS compliance report includes the information and supporting documentation required by Commission Rule R8-67(c), and, therefore, the Commission concludes that NTE's 2018 REPS compliance report should be approved.

NCEMC

On August 29, 2019, NCEMC filed its 2018 REPS compliance report. NCEMC's compliance report indicates that NCEMC's 2017 total retail sales were 12,973,377 MWh; therefore, NCEMC's general REPS obligation of ten percent of 2017 retail sales is 1,297,338 RECs, and its solar set-aside requirement, based on 0.2 percent of 2017 sales, is 25,947 solar RECs. Further, NCEMC's share of the 2018 poultry waste requirement is 29,433 poultry waste RECs. NCEMC's 2018 REPS compliance sub-account in NC-RETS demonstrates that NCEMC met its 2018 REPS requirements by submitting the required number of RECs for retirement based upon the foregoing sales levels and REPS requirements.

In its April 23 comments, the Public Staff states that NCEMC's 2018 REPS compliance report and its NC-RETS sub-account indicate that it met its REPS requirements for 2018. 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;

(2) 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 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. (GDS), as well as other customer-specific reports.[1]

The Public Staff further recommends that the Commission approve NCEMC's 2018 REPS compliance report, including the M&V results for the EECs NCEMC earned in 2018.

Based upon the foregoing and the entire record in this proceeding, including NCEMC's 2018 REPS compliance report, the data in NCEMC's 2018 REPS compliance sub-account in NC-RETS, and the comments of the Public Staff, the Commission determines that NCEMC complied with its 2018 REPS requirements, and that the RECs and EECs in NCEMC's 2018 REPS compliance sub-account in NC-RETS should be retired. Further, the Commission finds that NCEMC's 2018 REPS compliance report includes the information and supporting documentation required by Commission Rule R8-67(c), and, therefore, the Commission concludes that NCEMC's 2018 REPS compliance report, including the M&V results for EECs earned in 2018, should be approved.

NCEMPA

On August 28, 2019, NCEMPA filed its 2018 REPS compliance report. NCEMPA's compliance report states that NCEMPA's total 2017 retail electric sales were 7,013,038 MWhs. Based on ten percent of its 2017 retail sales, NCEMPA's 2018 REPS obligation is 701,304 RECs, and, based on 0.2 percent of NCEMPA's total 2017 retail sales, its solar set-aside obligation is 14,027 solar RECs. NCEMPA's share of the poultry waste set-aside requirement is 16,098 poultry waste RECs. Consistent with these requirements, the data in NC-RETS indicates that NCEMPA submitted the required number of RECs for retirement based upon the foregoing sales levels and REPS requirements.

In its April 23 comments, the Public Staff states that NCEMPA's 2018 REPS compliance report and NC-RETS compliance sub-account indicate that NCEMPA met its REPS requirements for 2018. 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 2018 REPS compliance report.

Based upon the foregoing and the entire record in this proceeding, including NCEMPA's 2018 REPS compliance report, the data in NC-RETS, and the Public Staff's comments, the Commission determines that the NCEMPA municipalities met their 2018 REPS obligations, and, therefore, the RECs in NCEMPA's 2018 REPS compliance sub-account in NC-RETS should be

[1] 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.

retired. Further, the Commission finds that NCEMPA's 2018 REPS compliance report includes the information and supporting documentation required by Commission Rule R8-67(c). The Commission, therefore, concludes that NCEMPA's 2018 REPS compliance report should be approved.

NCMPA1

On August 28, 2019, NCMPA1 filed its 2018 REPS compliance report. NCMPA1's compliance report states that NCMPA1's total 2017 retail sales were 4,933,026 MWhs. Based on ten percent of its 2017 total retail sales, NCMPA1's 2017 REPS obligation is 493,303 RECs. Based upon the 2018 solar set-aside requirement of 0.2 percent, NCMPA1's solar set-aside obligation is 9,867 solar RECs, and its share of the poultry waste set-aside requirements is 11,235 poultry waste RECs. Consistent with these requirements, the data in NC-RETS indicates that NCMPA1 met its 2018 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 2018. The Public Staff notes that NCMPA1 implements EE programs, it no longer tracks EE savings or uses EECs for compliance due to high M&V costs. The Public Staff recommends that the Commission approve NCMPA1's 2018 REPS compliance report.

Based upon the foregoing and the entire record in this proceeding, including NCMPA1's 2018 REPS compliance report, the data in NC-RETS, and the Public Staff's comments, the Commission concludes that the NCMPA1 municipalities met their 2018 REPS obligations, and, therefore, the RECs in NCMPA1's 2018 REPS compliance sub-account in NC-RETS should be retired. Further, the Commission finds that NCMPA1's 2018 REPS compliance report includes the information and supporting documentation required by Commission Rule R8-67(c). The Commission, therefore, concludes that NCMPA1's 2018 REPS compliance report should be approved.

TVA

On October 22, 2019, TVA filed its 2018 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 2018 REPS compliance report indicates that its total 2017 retail sales were 582,800 MWhs. Based upon the ten percent requirement, TVA's 2018 REPS requirement is 58,280 RECs. Based on the solar set-aside requirement of 0.2 percent, TVA's 2018 solar set-aside requirement is 1,166 solar RECs. TVA's share of the 2018 aggregate poultry waste set-aside requirement is 1,357 poultry waste RECs. The data in TVA's 2087 compliance sub-account in NC-RETS evidences that TVA met its REPS requirements for 2018 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 2018 REPS compliance report and NC-RETS compliance sub-account demonstrates that TVA met the REPS requirements for 2018. The Public Staff notes that TVA did not use any EECs for REPS compliance in 2018, 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 2018 REPS compliance report.

Based upon the foregoing and the entire record in this proceeding, including TVA's 2018 REPS compliance report, the data in NC-RETS, and the Public Staff's comments, the Commission determines that TVA's electric distributors met their 2018 REPS requirements, and that the RECs and EECs in TVA's 2018 REPS compliance sub-account in NC-RETS should be retired. Further, the Commission finds that TVA's 2018 REPS compliance report includes the information and supporting documentation required by Commission Rule R8-67(c). The Commission, therefore, concludes that TVA's 2018 REPS compliance report should be approved.

Waynesville

On September 16, 2019, Waynesville filed its 2018 REPS compliance report. Waynesville's compliance report indicates that its total 2017 retail sales were 85,538 MWhs. Based upon the ten percent general REPS requirement, Waynesville's total 2018 REPS compliance obligation is 8,554 RECs. Based upon the solar set-aside requirement of 0.2%, Waynesville's solar set-aside requirement is 171 solar RECs. Waynesville's share of the 2018 aggregate poultry waste set-aside requirement is 206 poultry waste RECs. The data in Waynesville's 2018 REPS compliance sub-account in NC-RETS demonstrates that Waynesville met its REPS requirements for 2018 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 2018 REPS compliance report and NC-RETS compliance sub-account indicate that Waynesville met the requirements for general RECs and solar RECs for 2018. The Public Staff further states that Waynesville did not use any EECs for REPS compliance in 2018. Additionally the Public Staff notes that Waynesville plans to enter into additional contracts to meet its REPS obligation and that Waynesville is currently evaluating EE programs and plans to meet its general requirement during the planning period with RECs from biomass, solar, wind, and its SEPA allocation. The Public Staff noted that Waynesville anticipates having sufficient resources to comply with the general and solar compliance requirements throughout the planning period, but Waynesville does not expect to meet the swine and poultry waste requirements during the planning period. The Public Staff stated that Waynesville is currently working to procure these RECs both through contracts and on the market, but is having trouble doing so due to its small size. Finally, Public Staff recommends that the Commission approve Waynesville's 2018 REPS compliance report.

Based upon the foregoing and the entire record in this proceeding, including Waynesville's 2018 REPS compliance report, the data in NC-RETS, and the Public Staff's comments, the Commission determines that Waynesville met its 2018 REPS requirements, and that the RECs in Waynesville's compliance sub-account in NC-RETS should be retired. Further, the Commission finds that Waynesville's 2018 REPS compliance report includes the information and supporting documentation required by Commission Rule R8-67(c). The Commission, therefore, concludes that Waynesville's 2018 REPS compliance report should be approved.

2019 REPS COMPLIANCE PLANS

Each EMC and municipal electric power supplier (or its utility compliance aggregator) filed in this docket the 2019 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 2019, 2020, and 2021 (the relevant planning period for the 2019 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 2019 REPS compliance plan filed by each EMC or municipal electric power supplier (or its utility compliance aggregator) and the comments of the Public Staff.

On July 15, 2020, in this docket, after the Public Staff filed its comments, ElectriCities of North Carolina, Inc. (ElectriCities), NCEMPA and NCMPA1 (jointly Power Agencies) filed a letter with the Commission requesting to reopen NC-RETS retail energy sales inputs for 2018 (2018 Inputs Update Request). In that request, the Power Agencies notified the Commission that ElectriCities discovered an error in the Power Agencies 2018 retail sales data submitted to NC-RETS. Specifically, 2018 retail sales for the Power Agencies were incorrectly entered into NC-RETS due to an error in the calculation methodology used in compiling total retail sales data. As a result, system losses were erroneously included in the inputted total sales number when such losses should not have been included in calculating total sales. For 2018, NCEMPA inputted its members' total sales as 7,689,807 MWh, which erroneously includes their total system losses of 349,505 MWh — an overstatement of 4.55%. The correct total retail sales for NCEMPA's member municipalities in 2018 was 7,340,302 MWh. Likewise, NCMPA1 inputted that its members' total 2018 sales were 5,394,312 MWh. That figure erroneously includes their total system losses of 217,267 MWh — an overstatement of 4.03%. The correct retail total sales for NCMPA1's member municipalities in 2018 was 5,177,045 MWh.

On August 31, 2020, the Commission issued an order allowing NCEMPA and NCMPA1 to update their 2018 total retail sales data in NC-RETS. In that order, the Commission specifically determined "that (1) any such adjustment shall not alter its load ratio share calculation nor the resulting allocated share of the aggregate poultry waste set-aside requirement relied upon by any electric power supplier in its REPS and REPS EMF Rider or 2019 Compliance Plan, as applicable; and (2) any such adjustment shall not alter any electric power suppliers' load ratio share calculation nor the resulting allocated share of the aggregate poultry waste set-aside requirement for 2019, 2020, and 2021." Because the adjustment anticipated by NCEMPA and NCMPA1 will result in a general REC credit for each agency as opposed to a REC deficit and will not impact either agencies' solar, swine, or poultry REC requirements for 2019 or future years, and because NCEMPA and NCMPA1 have been ordered to provide updated information regarding corrections to the agencies' retired RECs subaccounts no later than September 28, 2020, the Commission is satisfied with NCEMPA's and NCMPA1's 2019 REPS compliance plan.

Based upon the foregoing and the entire record in this proceeding, including the 2019 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 2018 REPS compliance requirements and filed 2018 REPS compliance reports and 2019 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 2018 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 the RECs and EECs in the 2018 REPS compliance sub-accounts in NC-RETS of EnergyUnited, FPWC, NTE, NCEMC, NCEMPA, NCMPA1 TVA, and Waynesville shall be retired;

2. That the 2018 REPS compliance reports for EnergyUnited, FPWC, NTE, NCEMC, NCEMPA, NCMPA1 TVA, and Waynesville shall be, and hereby are, approved;

3. That the 2019 REPS compliance plans for EnergyUnited, FPWC, NTE, NCEMC, NCEMPA, NCMPA1 TVA, and Waynesville 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 16th day of September, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-100, SUB 166

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Rulemaking Proceeding to Amend Filing Requirements for Application for Certificate of Public Convenience and Necessity Pursuant to Commission Rules R8-64 and R8-71(k)	))))	ORDER ADOPTING AMENDMENTS TO COMMISSION RULES R8-64(b)(6)(iii)(a) AND R8-71(k)(2)(iii)(6)

BY THE COMMISSION: On April 15, 2020, in Docket No. E-100, Sub 158 the Commission issued its Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in its 2018 biennial avoided cost proceeding (2018 Avoided Cost Order). In Findings of Fact Nos. 9 and 10 of the 2018 Avoided Cost Order the Commission found:

> 9. As a result of changes to the on- and off-peak hours being implemented in this Order, it is appropriate to waive the requirements of Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6) and to require an applicant for a certificate of public convenience and necessity (CPCN) to submit information regarding the projected annual production profile of the proposed generating facility, until such time as the Commission adopts revisions to these Rules.
>
> 10. It is appropriate to consider amendments to the requirements of Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6) to include information regarding the annual energy production profile and other factors influencing the shape of the production profile in a generic proceeding.

Commission Rule R8-64(b)(6)(iii) provides filing requirements for an application for a CPCN by an applicable electric generating facility entering into a contract of five years or more that is a non-solar photovoltaic facility larger than 5 MW or a solar photovoltaic facility larger than 25 MW. Commission Rule R8-71(k)(2)(iii) provides the filing requirements for a CPCN application for a utility-owned renewable energy facility selected in the Competitive Procurement of Renewable Energy (CPRE) Program pursuant to N.C. Gen. Stat. § 62-110.8.

In the 2018 Avoided Cost Order the Commission granted the limited waiver discussed in Finding of Fact No. 9 to allow CPCN applicants to substitute the following information for that currently required in Rules R8-64(b)(6)(iii)(a) and R8-71(k)(2)(iii)(6):

> The projected annual hourly production profile for the first full year of operation of the renewable energy facility in kilowatt-hours, including an explanation of potential factors influencing the shape of the production profile, including fixed tilt or tracking panel arrays, inverter loading ratio, over-paneling, clipped energy, or inverter AC output power limits.

2018 Avoided Cost Order at 30. The Commission also held that the "limited waiver allowed pursuant to this Order shall be in effect from the date of this Order until the Commission adopts revisions to Commission Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6)." *Id.*

On May 12, 2020, the Commission issued an Order Initiating Rulemaking and Requesting Comments in this proceeding (Rulemaking Order) for the purpose of considering permanent adoption of the temporary waiver allowed in the 2018 Avoided Cost Order. The Rulemaking Order made Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLP (DEP; together with DEC, Duke), and Virginia Electric and Power Company, Inc., d/b/a Dominion Energy North Carolina (DENC) parties of record in this proceeding and further recognized the participation of the Public Staff pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e). The Rulemaking Order established a schedule for intervention and receipt of comments and reply comments on whether to make permanent the temporary changes to Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6).

The North Carolina Sustainable Energy Association (NCSEA) and the North Carolina Clean Energy Business Alliance (NCCEBA) petitioned and were allowed to intervene in this proceeding; the intervention of the North Carolina Attorney General's Office (AGO) is recognized pursuant to N.C.G.S. § 62-20.

On June 5, 2020, Duke and DENC filed letters stating that they do not oppose the proposed revisions to Rules R8-64(b)(iii) and R8-71(k)(2)(iii)(6).

Also, on June 5, 2020, the Public Staff filed comments that recommend one minor change to the proposed amendment, which is italicized for emphasis:

> The projected annual hourly production profile for the first full year of operation of the renewable energy facility in kilowatt-hours, including an explanation of potential factors influencing the shape of the production profile, including *the following if applicable:* fixed tilt or tracking panel arrays, inverter loading ratio, over-paneling, clipped energy, or inverter AC output power limits.

Public Staff's Comments at 3.

On June 26, 2020, Duke, DENC, and NCCEBA filed reply comments. In summary, NCCEBA states that it has no objection to the proposed amendment of Commission Rules R8-64(b)(iii) and R8-71(k)(2)(iii)(6). Duke and DENC specifically state that they have no objection to the Public Staff's proposed modification. No other parties filed initial or reply comments.

DISCUSSION AND CONCLUSIONS

The Commission has carefully considered all comments and reply comments, including the Public Staff's provision revisions. The Commission notes that no party opposed the proposed amendments to Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6) or the revisions proposed by the Public Staff.

Based upon the foregoing and the entire record in this proceeding, the Commission finds good cause to approve as final the proposed amendments to Rules R8-64(b)(6)(iii)(a) and R8-71(k)(2)(iii)(6), including the revisions proposed by the Public Staff in its initial comments. Red-lined and clean versions of the amended rules are attached hereto as Appendix A and Appendix B.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of August, 2020.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

APPENDIX A
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Amended Rule R8-64(b)(6)(iii)

(iii) Exhibit 8 shall contain:

a. <u>The projected annual hourly production profile for the first full year of operation of the renewable energy facility in kilowatt-hours, including an explanation of potential factors influencing the shape of the production profile, including the following, if applicable: fixed tilt or tracking panel arrays, inverter loading ratio, over-paneling, clipped energy, or inverter AC output power limits;</u> ~~A detailed explanation of the anticipated kilowatt and kilowatt-hour outputs, on-peak and off-peak, for each month of the year. The explanation shall include a statement~~

~~of the specific on peak and off peak hours underlying the applicant's quantification of anticipated kilowatt and kilowatt hour outputs;~~

b. A detailed explanation of all energy inputs and outputs, of whatever form, for the project, including the amount of energy and the form of energy to be sold to each purchaser; and
c. A detailed explanation of arrangements for fuel supply, including the length of time covered by the arrangements, to the extent known at the time of the application.

Amended Rule R8-71(k)(2)(iii)

(iii) Exhibit 3 shall include:

1. The nature of the renewable energy facility, including the type and source of its power or fuel;
2. A description of the buildings, structures and equipment comprising the renewable energy facility and the manner of its operation;
3. The gross and net projected maximum dependable capacity of the renewable energy facility as well as the renewable energy facility's nameplate capacity, expressed as megawatts (alternating current);
4. The projected date on which the renewable energy facility will come on line;
5. The service life of the project;
6. The projected annual hourly production profile for the first full year of operation of the renewable energy facility in kilowatt-hours, including an explanation of potential factors influencing the shape of the production profile, including the following, if applicable: fixed tilt or tracking panel arrays, inverter loading ratio, over-paneling, clipped energy, or inverter AC output power limits; ~~The projected annual production of the renewable energy facility in kilowatt-hours, including a detailed~~

APPENDIX A
PAGE 2 OF 2

~~explanation of the anticipated kilowatt and kilowatt-hour outputs, on-peak and off-peak, for each month of the year;~~ and

7. The projected annual production of renewable energy certificates that is eligible for compliance with the State's renewable energy and energy efficiency portfolio standard.

APPENDIX B
PAGE 1 OF 1

Amended Rule R8-64(b)(6)(iii)

(iii) Exhibit 8 shall contain:

a. The projected annual hourly production profile for the first full year of operation of the renewable energy facility in kilowatt-hours, including an explanation of potential factors influencing the shape of the production profile, including the following, if applicable: fixed tilt or tracking panel arrays, inverter loading ratio, over-paneling, clipped energy, or inverter AC output power limits;
b. A detailed explanation of all energy inputs and outputs, of whatever form, for the project, including the amount of energy and the form of energy to be sold to each purchaser; and
c. A detailed explanation of arrangements for fuel supply, including the length of time covered by the arrangements, to the extent known at the time of the application.

Amended Rule R8-71(k)(2)(iii)

(iii) Exhibit 3 shall include:

1. The nature of the renewable energy facility, including the type and source of its power or fuel;
2. A description of the buildings, structures and equipment comprising the renewable energy facility and the manner of its operation;
3. The gross and net projected maximum dependable capacity of the renewable energy facility as well as the renewable energy facility's nameplate capacity, expressed as megawatts (alternating current);
4. The projected date on which the renewable energy facility will come on line;
5. The service life of the project;
6. The projected annual hourly production profile for the first full year of operation of the renewable energy facility in kilowatt-hours, including an explanation of potential factors influencing the shape of the production profile, including the following, if applicable: fixed tilt or tracking panel arrays, inverter loading ratio, over-paneling, clipped energy, or inverter AC output power limits; and
7. The projected annual production of renewable energy certificates that is eligible for compliance with the State's renewable energy and energy efficiency portfolio standard.

GENERAL ORDERS – TELECOMMUNICATIONS

DOCKET NO. P-100, SUB 110

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Telecommunications Relay	)	ORDER APPROVING
Service (TRS), Relay North Carolina	)	SELECTION OF CONTRACTOR

BY THE COMMISSION: On February 18, 2020, the Department of Health and Human Services (DHHS) issued a Request for Proposals (RFP) to select a vendor to provide telecommunications relay service to North Carolina citizens. The new contract will be effective from January 1, 2021 to December 31, 2024. Pursuant to N.C. Gen. Stat. § 62-157, DHHS is charged with administering the statewide telecommunications relay service program, including its establishment, operation, and promotion. Pursuant to N.C.G.S. § 62-157(e) and as part of its administration of the program, DHHS is authorized to contract out provision of this service for four-year periods to one or more service providers, using the State bidding process prescribed in N.C.G.S. § 143-129. The present contractor is Sprint Communications Company, LP (Sprint). The present contract, originally scheduled to expire on June 30, 2020, has been amended to expire on December 31, 2020.

The Public Staff presented the results of DHHS' process of selecting a contractor for the 2021-2024 time period at the Commission's Regular Staff Conference on October 26, 2020. The Public Staff stated that two companies submitted proposals in response to the RFP, Sprint and Hamilton Relay, Inc. The evaluation committee consisted of Rebecca Rosenthal, Telecommunications Resources Program Manager; Kevin Earp, Rehabilitation Program Specialist on Deafness and Communicative Disorders; Kimberly Harrell, Deaf-Blind State Coordinator & Assistive Technology Program Specialist; Tammy Koger, Director NC Assistive Technology Program; Meghan Prewett, Administrative Officer III, DHHS; George Maldonado, Systems Administrator III, DHHS Information Technology, Division of Services for the Deaf and Hard of Hearing; and Jo Ann Martin, Office of Internal Auditor, Risk Mitigation & Audit Monitoring.

In its review, the evaluation committee considered the following: technical merit, qualifications, customer service, outreach, advertising program, and costs. The evaluation committee then weighed and scored each bidding vendor's performance with regard to these considerations.

When evaluated pursuant to the considerations listed above, Sprint achieved the highest score and as a result, the evaluation committee recommends that Sprint be selected as the new contractor. The committee's recommendation and the evaluation summary, along with the vendor's proposals in response to the RFP, have been provided to, and are currently being reviewed by, the DHHS Office of Procurement, Grants, and Contract Services and a contract specialist at the Information Technology Services (ITS) Statewide Procurement Office.

The RFP was released seeking a per minute cost for Telecommunications Relay Services (TRS) and Captioned Telephone Services (CTS). The RFP also allowed vendors to submit alternate costing structures. Sprint submitted an alternate cost that allows monthly reoccurring costs (MRC), and this alternate cost structure represents the best value for DHHS. The current contract's MRC is $130,780, an amount that includes TRS, CTS, and Relay Conferencing Captioning (RCC). RCC is a free service available for North Carolina residents who are deaf or hard of hearing to actively participate in multi-party teleconference calls or web conferences by reading live captions through a web browser on a computer or mobile device.

Sprint's alternate cost proposal in its bid for the forthcoming contract for TRS and CTS is an MRC of $100,000, which includes TRS Services Outreach, a vital ancillary to the contract; however, it does not include RCC. Sprint's bid response offers the RCC at a rate of $3.35 per minute (the current contract cost per minute is $3.21). During 2019, RCC usage averaged 5,600 minutes per month. This amount of use is not expected to lessen because of the current pandemic conditions. The monthly cost for RCC is estimated to be $18,760. The monthly cost for all services provided under the contract is estimated to be $118,760. Thus, the annual cost of the contract is estimated to be $1,425,120, or a total expenditure of $5,700,480 over the life of the contract (4 years). After careful analysis of all Division expenditures including this new contract amount, DHHS has determined that it will not create a need for a surcharge rate change.

N.C.G.S. § 62-157(h) provides that the Commission has the same power to regulate TRS as it has to regulate any other public utility subject to the provisions of Chapter 62. DHHS has, historically, sought the approval of the Commission prior to the selection of the new contractor. The Public Staff has consulted with representatives of DHHS regarding its selection of Sprint as the contractor. The Public Staff recommends that the Commission approve the selection of Sprint as the contractor for relay services for the four-year period beginning January 1, 2021, and ending on December 31, 2024. This approval will not result in the need for an increase in the TRS monthly surcharge at this time.

Based on the foregoing and the recommendation of the Public Staff, the Commission concludes that it is appropriate to approve DHHS's selection of Sprint as the vendor to provide relay services in North Carolina for the four-year period beginning January 1, 2021, and ending December 31, 2024.

IT IS, THEREFORE, ORDERED that DHHS's selection of Sprint as the contractor to provide TRS in North Carolina for the four-year period beginning January 1, 2021, and ending December 31, 2024, is approved.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of October, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. P-100, SUB 167

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition of Sprint to Reduce Intrastate Switched) Access Rates of Incumbent Local Exchange) Carriers in North Carolina)	ORDER GRANTING JOINT PETITION

BY THE COMMISSION: On March 17, 2020, the Joint Petitioners[1] filed a Joint Petition for Order Confirming Amendment and Termination of Revenue Stability Fund (the Joint Petition) requesting that the Commission approve their agreement that the Revenue Stability Fund (RSF) be phased down and eliminated over a three-year period based on the schedule outlined in the Joint Petition and the Amendment to the RSF Agreement attached thereto.

On March 23, 2020, the Commission issued an Order Requesting Comments on Joint Petition. On April 2, 2020, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a letter in lieu of initial comments. On April 13, 2020, the Joint Petitioners filed a proposed order in lieu of reply comments. No other Parties filed any initial or reply comments.

The Joint Petition

The Joint Petitioners note that pursuant to the Commission's Order Holding Docket in Abeyance Pending Further Commission Order issued on July 10, 2012 in Docket No. P-100, Sub 167 (In the Matter of Petition of Sprint to Reduce Intrastate Switched Access Rates of Incumbent Local Exchange Carriers in North Carolina), the Joint Petitioners submit their Joint Petition regarding outstanding issues concerning the RSF and propose that the Commission approve their agreement that the RSF be phased down and eliminated over a three-year period that would commence on the 20th day of the first month more than 30 days after the Commission grants the Joint Petition and issues an order confirming the Parties' Amendment to the RSF Agreement.

The Joint Petitioners further note that in the July 10, 2012 Order, the Commission concluded on page 22 that, "[i]f it is determined by the parties that an issue remains concerning the Revenue Stability Fund after the July 3, 2012 tariffs are in effect, the Commission requests that the Public Staff or any other party file a motion with the Commission specifically detailing any outstanding issues that remain concerning the Revenue Stability Fund and a proposed course of action the Commission should take."

[1] The Joint Petitioners include: AT&T North Carolina (previously known as BellSouth), RiverStreet (previously known as Barnardsville, Ellerbe, Saluda, Service, Tri-County TMC, and Wilkes TMC), Comporium (previously known as Citizens), Randolph TMC (previously known as Randolph), Surry TMC (previously known as Piedmont TMC), Town of Pineville d/b/a Pineville Telephone Company, Yadkin TMC, Star TMC, Skyline TMC, ATMC (previously known as Atlantic TMC), North State Telephone Company, Windstream (previously known as Concord, Alltel Carolina, and Lexcom), Frontier (previously known as Contel and GTE), and CenturyLink (previously known as Carolina, Central, and Mebtel).

The Joint Petitioners note that the RSF was established in 1994 in order to mitigate the revenue losses sustained by smaller incumbent local exchange companies (ILECs) as a result of the North Carolina intraLATA access toll pool being terminated on January 1, 1994.

The Joint Petitioners maintain that it was agreed among all of the North Carolina ILECs that the small ILECs who were net recipients from the intraLATA toll pool would have been adversely affected upon the pool's termination without the establishment of the RSF. The Joint Petitioners further note that under the RSF, all ILECs contribute to the fund and disbursements are provided to those ILECs with under 50,000 access lines. The Joint Petitioners state that the bulk of the funding disbursed through the RSF is provided by the ILECs that were originally net contributors to the intraLATA toll pool.

The Joint Petitioners comment that in 1999, they entered into an Agreement revising the original RSF in anticipation of the North Carolina universal service fund being implemented by July 1, 2001. The Joint Petitioners note that this Agreement was with the understanding that if an intrastate universal service fund was not to be implemented in North Carolina by January 1, 2002, the Central Administrator[1] of the RSF, agreed by the Parties to be BellSouth (now d/b/a AT&T North Carolina), would convene a meeting with the Parties by October 31, 2001, to assess any need to continue the RSF beyond January 1, 2002.

The Joint Petitioners note that the October 31, 2001 meeting was never convened, and until recently there has been no meeting or discussion in the past 19 years regarding any need to amend or terminate the Agreement because of changes within the industry.

The Joint Petitioners maintain that the telecommunications industry in North Carolina is competitive and that products and service offerings are diverse. They note that in the years since the Parties entered into the Agreement, services such as Voice over Internet Protocol (VoIP) and wireless have been replacing traditional access lines at a tremendous rate.

The Joint Petitioners state that various Parties compete with each other and some recipients of RSF money now compete vigorously with some carriers who pay into the fund, and vice versa, and the Parties have concluded that circumstances have sufficiently changed, in terms of the robust marketplace and the drastic and continuing loss of access lines, to warrant phasing out the RSF as a mechanism for providing financial support to small ILECs. The Joint Petitioners further note that in the Agreement, the Parties expressly recognized that the RSF was not expected to continue endlessly and, at the time of its establishment, the need to continue the RSF beyond January 1, 2002 was to be discussed, as it was contemplated that a State universal service fund would be in place by then. The Joint Petitioners maintain that there were no discussions regarding modification or termination of the RSF until April 2019.

The Joint Petitioners assert that in accordance with paragraph 9 of the Agreement, the Parties may modify the Agreement by signed written agreement of all the Parties. They note that the Parties have executed a modification of the Agreement on March 12, 2020, that requires a

[1] The Central Administrator of the RSF is responsible for collecting and distributing funds in accordance with the terms of the Agreement.

tiered three-year phase out and termination of the RSF. The Joint Petitioners attached a copy of the Amendment to their Joint Petition.

The Joint Petitioners note that the approach agreed to by the Parties provides for the RSF to be phased out and terminated after three years, while lessening the immediacy of the monetary impact on those small ILECs that are net-recipients from the RSF. They maintain that under the terms of the Amendment, the Parties will phase out the RSF on the following schedule:

(1) The Parties shall reduce RSF collections and disbursements by 25% of the amount originally set forth in the Agreement, effective on the 20th day of the first month more than 30 days after the date the Commission grants the Joint Petition and issues an order confirming the Parties' Amendment to the Agreement;

(2) The Parties shall reduce RSF collections and disbursements by an additional 25%, for a total reduction of 50% of the collections and disbursements as set forth in the Agreement, effective one year after the initial reduction becomes effective;

(3) The Parties shall reduce RSF collections and disbursements by an additional 25%, for a total reduction of 75% of the collections and disbursements as set forth in the Agreement, effective two years after the initial reduction becomes effective; and

(4) The RSF will be terminated, effective three years after the initial reduction becomes effective.

The Joint Petitioners assert that given that the Agreement and Amendment are commercial agreements established and agreed to by and between the Parties, an order approving the amendment and termination of the RSF, in accordance with the Parties' agreement, should be entered by the Commission without the need for further proceedings.

In addition, the Joint Petitioners acknowledge and agree that the agreement to phase out and terminate the RSF as provided in the Amendment is without prejudice to the right of any provider, including any Party, to petition the Commission for creation of a State universal service fund, as contemplated by the Parties in the Agreement and as provided for in N.C. Gen. Stat. §§ 62-110(f1) and 62-133.5(m).

The Joint Petitioners also note that the Parties agree that the provisions of the Joint Petition, the Amendment, and any other documents relating to the phase out and termination of the RSF reflect the compromise and settlement among the Parties as to all of the issues covered hereby. They state that no Party waives any right to assert or oppose any position in any future proceeding or docket before the Commission that relates in any way to the matters which are the subject of the Joint Petition and the Amendment.

The Joint Petitioners request that the Commission grant the Joint Petition expeditiously and issue an order confirming the Parties' Amendment, agreeing that RSF collections and disbursements will be reduced according to the schedule outlined in paragraph 15 of the Joint

Petition, and that the RSF will be terminated effective three years after the initial reduction becomes effective.

Initial Comments

On April 2, 2020, the Public Staff filed a letter in lieu of comments. The Public Staff notes that it has reviewed the Joint Petition and does not object at this time to the grant of the relief requested. The Public Staff further maintains that it reserves the right to file reply comments based on its review of any initial comments.

The Public Staff recommends that should the Commission grant the Joint Petition, the Commission require the Joint Petitioners to file a revised Industry Access Services Tariff to reflect the terms of the amended agreement, and, upon the effective date of termination of the RSF, the Commission be notified and the Industry Access Services Tarff be revised accordingly.

No other party filed any initial comments on the Joint Petition.

Reply Comments

On April 13, 2020, the Joint Petitioners filed a proposed order in lieu of reply comments.

Discussion and Conclusions

After reviewing the Joint Petition, including its attachments, and the letter filed by the Public Staff in lieu of comments, the Commission finds good cause to grant the Joint Petition. The Commission finds that all Parties were given the opportunity to express concern or disagreement with the Joint Petition, and the Commission did not receive any comments expressing opposition to the Joint Petition. Therefore, the Commission concludes that it is appropriate to grant the Joint Petition.

Further, the Commission finds it appropriate to adopt the recommendations offered by the Public Staff in its April 2, 2020 letter. Therefore, the Joint Petitioners are hereby required to file as soon as reasonably practicable a revised Industry Access Services Tariff to reflect the terms of the amended agreement. In addition, upon the effective date of termination of the RSF, the Joint Petitioners shall notify the Commission that the RSF has been terminated and file a revised Industry Access Services Tariff.

Finally, the Chief Clerk shall provide a copy of this Order to the North Carolina Rural Electrification Authority for informational purposes.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of April, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

DOCKET NO. P-100, SUB 170

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Tariff Filings Made by Local Exchange Carriers in Compliance with the Federal Communications Commission's Connect America Fund Order	))))	ORDER GRANTING THE PUBLIC STAFF'S MOTION WITH AN EFFECTIVE DATE OF JULY 1, 2020 FOR RATE CHANGES

BY THE COMMISSION: On May 26, 2020, the Public Staff filed a Motion for Order Requiring Filing of Information Regarding July 1, 2020, Access Rate Changes (motion).

In its motion, the Public Staff requests that the Commission issue an order requiring filings from certain carriers as outlined in the motion (including rate of return carriers and competing local providers that benchmark access rates to rate of return carriers) showing their compliance with the eighth and final step of the transition plan for intrastate access rate changes (effective July 1, 2020) mandated by the Federal Communications Commission's November 18, 2011 Universal Service Fund (USF)/ Intercarrier Compensation (ICC) Transformation Order by no later than Tuesday, June 16, 2020.

The Public Staff further notes 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 recommends should make an appropriate filing regarding their 2020 switched access rate changes. The Public Staff states 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 27, 2020, the Commission issued an Order Requesting Comments on the Public Staff's Motion.

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 Tuesday, June 16, 2020, with an effective date of July 1, 2020, as appropriate.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of June, 2020.

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 Deregulation of Transportation of Household Goods within North Carolina	))	ORDER APPROVING ANNUAL RATE ADJUSTMENT

BY THE COMMISSION: On July 25, 2002, the Commission issued an Order Ruling on Motions and Comments addressing certain issues regarding the deregulation of household goods transportation within North Carolina. That Order specifically addressed issues relating to the Commission's adoption of the Maximum Rate Tariff No. 1 (MRT) and the methodology for use in adjusting the maximum rates contained therein.

In that Order, the Commission concluded that (1) annual increases in the MRT should be based upon the Implicit Price Deflator (IPD) of the Gross Domestic Product (GDP); (2) the increases would be on an annual basis on a specific date; and (3) the first increase would be one year after the effective date of the MRT. In addition, the Commission concluded that in the interim between annual adjustment dates, the Commission would allow movers to petition the Commission for an adjustment. Upon the filing of such a petition, it would be set for hearing, and the mover(s) would be required to show just and reasonable cause for the requested increase.

On September 24, 2002, the Commission issued an Order Ruling on Comments and Reply Comments to Maximum Rate Tariff. In that Order, the Commission adopted specific changes and amendments to the proposed MRT and reiterated its decision that the procedure for adjusting maximum rates on an annual basis should be to use the IPD of the GDP as the methodology. The Commission also specified that the purpose of the MRT is to establish for all carriers one set of maximum ceiling rates and to allow the carrier and shipper to negotiate a price below the maximum rates.

On November 1, 2002, the Commission issued a Final Order Ruling on Household Goods Transportation and Maximum Rate Tariff No. 1. That Order approved the provisions of the MRT to first become effective on January 1, 2003. The first annual rate adjustment in the MRT was an increase of 1.26%, effective January 1, 2004. Thereafter, annual rate adjustments have been approved and implemented every January 1st, using the IPD of the GDP, percentage-change methodology.

Over the past ten years, the following annual rate adjustments were approved:

No.	Effective Date	Increase / (Decrease)
1	January 1, 2011	1.20%
2	January 1, 2012	2.40%
3	January 1, 2013	1.70%
4	January 1, 2014	1.40%
5	January 1, 2015	1.60%
6	January 1, 2016	1.30%
7	January 1, 2017	1.50%
8	January 1, 2018	1.80%
9	January 1, 2019	(2.75%)
10	January 1, 2020	1.80%

The Commission has determined that the annual rate adjustment which shall be approved to become effective January 1, 2021, based upon the IPD of the GDP, is a percentage increase of 1.10%.

IT IS, THEREFORE, ORDERED as follows:

1. That effective January 1, 2021, a rate increase of 1.10% to the maximum rates and charges contained in the Maximum Rate Tariff No. 1 shall be, and is hereby, approved; and

2. That revised pages to the Maximum Rate Tariff No. 1 reflecting the new annual rates and charges shall be either postal mailed or emailed under separate cover to all Commission-certificated household goods carriers along with the monthly tariff revisions reflecting changes such as recently certificated carriers, cancelled certificates, and authorized suspensions.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of November, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

DOCKET NO. T-100, SUB 111
DOCKET NO. T-4802, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. T-100, SUB 111 In the Matter of Petition for Declaratory Ruling by Bellhops, Inc. DOCKET NO. T-4802, SUB 0 In the Matter of Application of BHH Services, LLC, d/b/a Bellhop Moving, 1110 Market Street, Suite 502, Chattanooga, Tennessee 37402 for Certificate of Exemption to Transport Household Goods	ORDER CONSOLIDATING DOCKETS, DISMISSING WITHOUT PREJUDICE PETITION FOR DECLARATORY RULING, AND ACCEPTING THE SETTLEMENT AGREEMENT

BY THE COMMISSION: By letter dated October 31, 2019, addressed to Mr. Nicholas Jeffries of the Commission staff, Bellhop, Inc. (Bellhop or Applicant),[1] requested that the Commission "acknowledge that the Company is properly operating in North Carolina as a property broker and that neither the Company nor the third-party motor carriers to which the Company tenders freight are required to obtain [household goods (HHG)] motor carrier [authority] under North Carolina law." Bellhop argued that it is not a household goods motor carrier but rather a broker that arranges for the transportation of property by third-party service providers and that neither Bellhop nor the third-party motor carriers to which it tenders freight are required to obtain a certificate of exemption under N.C. Gen. Stat. § 62-262. Bellhop further argued that it is exempt from Commission regulation by virtue of the limited service exclusion contained in 49 U.S.C. § 13102(12)(C).

Bellhop attached to its request a letter dated September 12, 2019, from Bellhop to Mr. Krishna Rajeev, Director, Transportation Rates Division of the Public Staff and a response dated October 7, 2019, from Mr. John Little, Staff Attorney for the Public Staff. In its September 12, 2019 letter to the Public Staff, Bellhop referenced an email that it received from the Public Staff on September 9, 2019, "suggesting that Bellhops may be violating North Carolina state law by advertising and otherwise offering to perform unauthorized [HHG] moving services in North Carolina." Bellhop argued to the Public Staff, as it did to the Commission, that it is a property broker, that it is not operating any equipment or trucks itself or performing any motor carrier services in North Carolina, and that it does not hold itself out as a household goods mover.

[1] On May 29, 2020, Bellhops, Inc., filed a name change to Bellhop, Inc., with the North Carolina Secretary of State.

Because Bellhop requested a determination by the Commission, the Commission deemed Bellhop's October 31, 2019 letter to be a petition for declaratory ruling, filed that letter in Docket No. T-100, Sub 111, and issued an order on February 27, 2020, allowing interested persons to intervene and file comments on whether Bellhop is exempt from Commission regulation.

From March 23 through March 27, 2020, the North Carolina Movers Association (NCMA), numerous certified moving companies, and the Public Staff filed comments. The parties recommended that the Commission determine that 49 U.S.C. § 13102(12)(C) does not exempt Bellhop from the need to obtain a certificate of exemption from the Commission.

On April 13, 2020, Bellhop filed with the Commission a Withdrawal of Petition for Request for Declaratory Ruling. Bellhop explains that it had not meant for either its September 12, 2019 or October 31, 2019 letters to be interpreted as a request for a declaratory ruling and thus filed the withdrawal to end any proceedings under Docket No. T-100, Sub 111.

On April 22, 2020, in Docket No. T-4802, Sub 0, BHH Services, LLC (BHH), a Bellhop subsidiary, filed with the Commission an Application for a Certificate of Exemption to Transport Household Goods (Application).

On May 7, 2020, in Docket T-4802, Sub 0, the NCMA filed comments regarding BHH's Application. In its comments the NCMA states that it is not protesting BHH's Application but lists several concerns, including: Bellhop's advertising the moving of household goods while not holding a certificate of exemption; that BHH's certificated name be BHH Services, LLC, d/b/a Bellhops, Inc. to avoid confusion; and that Bellhop follow the Maximum Rate Tariff for intrastate moves in North Carolina. The NCMA also believes that Bellhop violated N.C.G.S. § 62-280.1 and that its violations should be addressed before BHH is to be issued a certificate of exemption.

On July 24, 2020, Bellhop and the Public Staff (jointly, Settling Parties) filed with the Commission a Settlement Agreement. Therein the Settling Parties represent that they discussed Bellhop's past practice of advertising the transportation of household goods in North Carolina without a certificate of exemption. The Public Staff maintains its contention that Bellhop's operations and advertising practices did not remove the need to obtain a certificate of exemption from the Commission. In contrast, Bellhop maintains that its operations and advertising practices conformed to the limited service exclusion contained in 49 U.S.C. § 13102(12)(C). The Settling Parties agree, however, that in the spirit of cooperation and to avoid prolonged litigation resolving this issue, Bellhop will pay the sum of $5,000 to the Commission to settle any past allegations of its having advertised the transportation of household goods in North Carolina without a certificate of exemption. The Public Staff states that, upon the agreement of Bellhop to pay the sum of $5,000 to the Commission, it does not object to the Commission accepting BHH's Application and issuing a certificate of exemption.

On August 24, 2020, BHH filed with the Commission an Amended Application for a Certificate of Exemption to Transport Household Goods (Amended Application) listing its certificated name as BHH Services, LLC, d/b/a Bellhop Moving.

On September 29, 2020, the NCMA filed comments with the Commission supporting the Settlement Agreement.

DISCUSSION AND CONCLUSIONS

The Commission notes that the Settlement Agreement reached between Bellhop and the Public Staff is supported by the NCMA and addresses Bellhop's past alleged operation in the transportation of household goods and advertising the same without a certificate of exemption issued by the Commission. The settlement entered into by Bellhop and the Public Staff requires Bellhop to pay the sum of $5,000 to the Commission, and with this payment the Public Staff does not object to the Commission granting BHH's Application and issuing it a certificate of exemption.

After careful consideration, and based upon the records in these dockets and the representations of the Public Staff, the Commission finds that good cause exists to consolidate these dockets, accept Bellhop's withdrawal, dismiss the petition for declaratory ruling filed in Docket No. T-100, Sub 111, and close that docket. Dismissal is without prejudice to the Commission's consideration of whether Bellhop or its subsidiaries are exempt from Commission regulation should the question arise again. The Commission further finds good cause to accept the Settlement Agreement between Bellhop and the Public Staff, and the Commission agrees with the Settling Parties that it is appropriate for Bellhop to pay a penalty in the amount of $5,000.00 to the Commission for any past allegations of advertising the transportation of household goods without having first obtained a certificate of exemption.

IT IS THEREFORE ORDERED as follows:

1. That the Settlement Agreement between Bellhop and the Public Staff is incorporated by reference herein and is hereby approved in its entirety;

2. That Bellhop will pay a penalty in the amount of $5,000 to the Commission; and

3. That an order on the Amended Application for a Certificate of Exemption to Transport Household Goods filed by Bellhop's subsidiary, BHH Services, LLC, d/b/a Bellhop Moving, will be issued once all payments and insurance documents have been received by the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 9th day of November, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Joann R. Snyder, Deputy Clerk

DOCKET NO. T-100, SUB 111
DOCKET NO. T-4802, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. T-100, SUB 111 In the Matter of Petition for Declaratory Ruling by Bellhops, Inc. DOCKET NO. T-4802, SUB 0 In the Matter of Application of BHH Services, LLC, d/b/a Bellhop Moving, 1110 Market Street, Suite 502, Chattanooga, Tennessee 37402 for Certificate of Exemption to Transport Household Goods	ORDER GRANTING APPLICATION FOR CERTIFICATE OF EXEMPTION

BY THE COMMISSION: By letter dated October 31, 2019, Bellhop, Inc. (Bellhop),[1] requested that the Commission "acknowledge that the Company is properly operating in North Carolina as a property broker and that neither the Company nor the third-party motor carriers to which the Company tenders freight are required to obtain [household goods (HHG)] motor carrier [authority] under North Carolina law." Because Bellhop requested a determination by the Commission, the Commission deemed Bellhop's October 31, 2019 letter to be a petition for declaratory ruling, filed that letter in Docket No. T-100, Sub 111, and issued an order on February 27, 2020, allowing interested persons to intervene and file comments. From March 23 through March 27, 2020, numerous parties filed comments.

On April 13, 2020, Bellhop filed with the Commission a Withdrawal of Petition for Request for Declaratory Ruling. Bellhop explained that it had not meant for either its September 12, 2019 or October 31, 2019 letters to be interpreted as a request for a declaratory ruling and thus filed the withdrawal to end any proceedings under Docket No. T-100, Sub 111.

On April 22, 2020, in Docket No. T-4802, Sub 0, BHH Services, LLC (BHH or Applicant), a Bellhop subsidiary, filed with the Commission an Application for a Certificate of Exemption to Transport Household Goods (Application).

On May 7, 2020, in Docket T-4802, Sub 0, the NCMA filed comments regarding BHH's Application.

On July 24, 2020, Bellhop and the Public Staff (jointly, Settling Parties) filed with the Commission a Settlement Agreement.

[1] On May 29, 2020, Bellhops, Inc., filed a name change to Bellhop, Inc., with the North Carolina Secretary of State.

On August 24, 2020, BHH filed with the Commission an Amended Application for a Certificate of Exemption to Transport Household Goods (Amended Application) listing its certificated name as BHH Services, LLC, d/b/a Bellhop Moving.

On September 29, 2020, the NCMA filed comments with the Commission supporting the Settlement Agreement.

On November 9, 2020, the Commission issued an Order Consolidating Dockets, Dismissing Without Prejudice Petition for Declaratory Ruling, and Accepting the Settlement Agreement in Dockets T-100, Sub 111 and T-4802, Sub 0. Among other things, the Commission ordered that the Settlement Agreement between Bellhop and the Public Staff was approved in its entirety; Bellhop will pay a penalty in the amount of $5,000 to the Commission; and an order on the Amended Application for a Certificate of Exemption to Transport Household Goods filed by Bellhop's subsidiary, BHH Services, LLC, d/b/a Bellhop Moving, will be issued once all payments and insurance documents have been received by the Commission.

Upon consideration of the Application and the entire record in these dockets, the Commission finds and concludes that the Applicant has complied with the terms and conditions of the Commission's November 9, 2020 Order as well as those 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 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 BHH Services, LLC, d/b/a Bellhop Moving, 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; and

6. That this Order shall constitute a certificate of exemption until formal Certificate of Exemption No. C-2968 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 14th day of December, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. W-100, SUB 57
DOCKET NO. W-100, SUB 62

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. W-100, SUB 57 In the Matter of Impact of The Federal Tax Cuts and Jobs Act on Contributions in Aid of Construction for Water and Wastewater Companies DOCKET NO. W-100, SUB 62 In the Matter of Annual Report Formats for Water and Wastewater Companies	)	ORDER SPECIFYING THE TYPES OF TAXABLE CIAC, ADOPTING CIAC REPORTING FORMAT IN ANNUAL REPORTS, AND REQUESTING THE PUBLIC STAFF TO BEGIN THE PROCESS OF REVISING THE TARIFFS OF WATER AND WASTEWATER COMPANIES

BY THE COMMISSION: On December 22, 2017, the Federal Tax Cuts and Jobs Act (Tax Act) was signed into law. 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 (or sewer) companies. Specifically, the Tax Act has now made CIAC taxable again for water and wastewater public utilities.

On October 5, 2018, in Docket No. W-100, Sub 57, 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 (October 5, 2018 Order). 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; (3) 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 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.

On August 26, 2019, the Commission issued its Order Addressing Federal Income Taxes on Contributions in Aid of Construction (August 26, 2019 Order). The Commission made the following conclusions, in addition to other findings, in the August 26, 2019 Order:

Reporting on CIAC and the Taxes Collected on CIAC: The Commission concluded that it did not have sufficient information as of the date of the August 26, 2019 Order to require a specific format for reports on CIAC and the taxes on CIAC collected by the water and wastewater companies. The Commission requested that the Public Staff work with both Aqua and CWSNC, and any other interested water or wastewater company, to: (1) develop a list of the specific types of property and non-property related to CIAC that are taxable; and (2) develop a format agreeable to all parties for the CIAC reporting to follow within the context of the annual report. The Public Staff was requested to file a report including specific recommendations on these issues within 45 days of the August 26, 2019 Order.

Tariff Revisions: The Commission concluded that, 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 to collect taxes on CIAC for each company. However, the Commission noted that the tariffs could not be updated until the specific types of CIAC were identified and each company determined which methodology it would seek Commission approval to use, as appropriate, and the Commission approved, as appropriate, the use of such methodology.

The Commission requested that the Public Staff determine when was 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.

On October 8, 2019, the Public Staff filed a Motion for an Extension of Time to file the report requested by the Commission in the August 26, 2019 Order by no later than November 22, 2019. The Commission granted the Public Staff's motion by Order dated October 9, 2019.

On November 22, 2019, the Public Staff filed its Report on the Classification and Reporting of CIAC and Request for Authorization to Revise Tariffs (Report). The Public Staff notes in its Report that on October 16, 2019, the Public Staff met with representatives of Aqua, CWSNC, ONSWC, and Pluris, LLC (collectively, the Utilities) and discussed various topics addressed by the August 26, 2019 Order, including the types of taxable CIAC and a format for reporting CIAC and taxes on CIAC in annual reports filed by water and wastewater companies. The Public Staff states that based on those discussions, the Public Staff is making the following recommendations:

Taxable CIAC: The Public Staff notes that during discussions with the Utilities, the Public Staff stated that all CIAC is taxable, including the following:

1) Connection or tap fees;

2) Capacity fees;

3) Meter installation fees;

4) Cash contributions from a developer used by a utility to construct plant;

5) Utility plant installed or paid for by the contributor and then conveyed by the contributor to the utility; and

6) Land conveyed by the contributor to the utility.

The Public Staff notes that none of the Utilities expressed disagreement with the Public Staff's statement.

CIAC Reporting Format: The Public Staff recommends that the Commission direct water and wastewater utilities to record the amount of each of the types, as outlined above, of CIAC received in their annual reports using the format shown in Attachment A to the Report. The Public Staff maintains that with the exception of specifying the types of CIAC listed in Lines seven through 12, the format shown in Attachment A is generally the same format the Commission required water and wastewater utilities to use to report CIAC in their annual reports following the enactment of the Federal Tax Reform Act of 1986 (Docket No. M-100, Sub 113). The Public Staff asserts that it proposed the CIAC reporting format shown in Attachment A to the Report to the Utilities and none expressed disagreement.

The Public Staff also notes in its Report that in addition to taxable CIAC and the CIAC reporting format, the Public Staff and the Utilities discussed the issue of for what CIAC Commission-regulated water and wastewater utilities must collect the gross-up from the CIAC contributor. The Public Staff states that it indicated that as stated in Ordering Paragraph No. 2 of the August 26, 2019 Order, 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 and after October 5, 2018 using the full gross-up method. The Public Staff notes that none of the Utilities expressed disagreement.

Finally, the Public Staff requests in its Report that the Commission issue an order authorizing the Public Staff to begin the process of revising the tariffs of water and wastewater companies to reflect the change in the taxability of CIAC as required by the Tax Act and outlined in the Commission's Orders in Docket No. W-100, Sub 57.

Discussion and Conclusions

Based upon the following, including the Public Staff's Report and the absence of disagreement by the Utilities as noted in the Report, the Commission finds it appropriate to specify that all CIAC is taxable, including: connection or tap fees; capacity fees; meter installation fees; cash contributions from a developer used by a utility to construct plant; utility plant installed or paid for by the contributor and then conveyed by the contributor to the utility; and land conveyed by the contributor to the utility. Further, the Commission finds it appropriate to adopt the CIAC reporting format included in the Report (with minor edits) and attached hereto as Appendix A for water and wastewater companies to use in their annual reports, effective the date of this Order, for use beginning with the annual reports due no later than April 30, 2020.

Appendix A of this Order is replacing the current Investment in Water and Sewer Utility System schedule included in the annual report format for both water and sewer companies with revenues of $200,000 or more (revised 1/2012) and for water and sewer companies with revenues of less than $200,000 (revised 1/2010). The Commission observes that replacing the Investment in Water and Sewer Utility System schedule in the annual report formats will require a renumbering of the pages in the annual report formats. Therefore, the Public Staff is requested to update the entire annual report format for both water and sewer companies with revenues of $200,000 or more (revised 1/2012) and for water and sewer companies with revenues of less than $200,000 (revised 1/2010) to reflect the new version of the Investment in Water and Sewer Utility System schedule adopted herein. The Public Staff is further requested to file these current versions with the Commission in a newly-created generic water and wastewater docket, Docket No. W-100, Sub 62, established by this Order to contain copies of the current annual report formats.

In addition, the Public Staff is hereby requested to begin the process of revising the tariffs of water and wastewater companies to reflect the change in the taxability of CIAC as required by the Tax Act and outlined in the Commission's Orders in Docket No. W-100, Sub 57. The Public Staff is requested to draft revised tariffs and submit the tariffs to the Commission for approval. The Public Staff is further requested to file a brief status report on the progress of the tariff revision process every 90 days from the date of this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That all CIAC is taxable, including: connection or tap fees; capacity fees; meter installation fees; cash contributions from a developer used by a utility to construct plant; utility plant installed or paid for by the contributor and then conveyed by the contributor to the utility; and land conveyed by the contributor to the utility;

2. That the reporting format attached hereto as Appendix A is adopted by the Commission for the required use by water and wastewater companies in their annual reports, effective the date of this Order, for use beginning with the annual reports due no later than April 30, 2020. Appendix A of this Order is replacing the current Investment in Water and Sewer Utility System schedule included in the annual report format for both water and sewer companies with revenues of $200,000 or more (revised 1/2012) and for water and sewer companies with revenues of less than $200,000 (revised 1/2010);

3. That because replacing the Investment in Water and Sewer Utility System schedule in the annual report formats will require a renumbering of the pages in the annual report formats, the Public Staff is requested to update the entire annual report format for both water and sewer companies with revenues of $200,000 or more (revised 1/2012) and for water and sewer companies with revenues of less than $200,000 (revised 1/2010) to reflect the new version of the Investment in Water and Sewer Utility System schedule adopted herein and shall file the current versions with the Commission in a newly-created generic water and wastewater docket, Docket No. W-100, Sub 62, established by this Order to contain copies of the current annual report formats; and

4. That the Public Staff shall begin the process of revising the tariffs of water and wastewater companies to reflect the change in the taxability of CIAC as required by the Tax Act and outlined in the Commission's Orders in Docket No. W-100, Sub 57; shall also draft revised tariffs and submit the tariffs to the Commission for approval; and shall file a brief status report on the progress of the tariff revision process every 90 days from the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of February, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

APPENDIX A

INVESTMENT IN WATER AND SEWER UTILITY SYSTEM
For the Year Ended December 31, _______

Line No.	Item (a)	Water (b)	Sewer (c)	Combined (d)
1.	Original cost of system(s)			
2.	Actual cost of all additions to system(s) since original construction			
3.	Total cost of system(s) to date (L1 plus L2)			
4.	Accumulated depreciation			
5.	Net cost of system(s) (L3 minus L4)			
6.	Cost of plant additions during this 12-month reporting period			
	Contributions in aid of construction (CIAC) (excluding gross-up) received during this 12-month reporting period			
7.	Connection or tap fees			
8.	Capacity fees			
9.	Meter installation fees			
10.	Cash contributions from a developer used by a utility to construct plant			
11.	Utility plant installed or paid for by the contributor and then conveyed by the contributor to the utility			
12.	Land conveyed by the contributor to the utility			
13.	Total CIAC (excluding gross-up) received during this 12-month reporting period (Sum of L7 thru L12)			
14.	Cumulative CIAC received (excluding gross-up)			
15.	Taxes collected on CIAC during this 12-month reporting period			
16.	Cumulative tax collected on CIAC			
17.	Taxes paid on CIAC collected during the previous 12-month reporting period			
18.	Cumulative tax paid on CIAC			

IMPORTANT: CIAC are generally defined in the National Association of Regulatory Utility Commissioners (NARUC) Uniform System of Accounts as money, services, or property received by the utility company from customers, developers, or any other source at no cost to the utility company which offsets the acquisition, improvement, or construction costs of the utility's property, facilities, or equipment to be used to provide utility service. Tap-on fees and meter installation fees are forms of CIAC.

GENERAL ORDERS – WATER AND SEWER

DOCKET NO. W-100, SUB 60

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition for Rulemaking to Implement N.C. Gen. Stat. § 62-133.1A, North Carolina Session Law 2018-51 (House Bill 351)	)))	ORDER ADOPTING COMMISSION RULE R7-41 AND COMMISSION RULE R10-28

BY THE COMMISSION: On December 31, 2019, in the above-captioned proceeding, Aqua North Carolina, Inc. (Aqua), and Carolina Water Service, Inc., of North Carolina (CWSNC) (together, Companies) filed a petition requesting that the Commission establish a rulemaking proceeding in this docket for the purpose of considering and adopting rules to implement N.C. Gen. Stat. § 62-133.1A, as enacted by North Carolina Session Law 2018-51 (House Bill 351). The Companies' petition provided a summary of the provisions of their proposed rules to implement the statute, as detailed below, and included as attachments to their petition proposed Commission Rule R7-41 for water utilities and Rule R10-28 for sewer utilities.

On January 13, 2020, the Commission issued an order establishing this proceeding as a rulemaking proceeding for the purpose of considering the adoption of the Commission Rule R7-41 for water utilities and Rule R10-28 for sewer utilities to implement N.C.G.S. § 62-133.1A, and setting dates for the filing of petitions to intervene and of initial and reply comments.

On February 4, 2020, the Commission issued an order allowing Old North State Water Company, LLC (ONSWC), to intervene in this proceeding as requested in its petition to intervene filed in this docket on January 17, 2020.

On April 30, 2020, the Public Staff filed its initial comments, which include recommended revisions to the rules that the Companies' proposed.

On June 1, 2020, the Companies filed reply comments.

Also on June 1, 2020, the North Carolina Attorney General's Office (AGO) filed a notice of intervention and reply comments.[1]

THE FAIR VALUE STATUTE

As enacted by Session Law 2018-51, N.C.G.S. § 62-133.1A (Fair Value Statute) provides as follows:

> (a) Election. – A water or wastewater public utility, as defined by G.S. 62-3(23)a.2., may elect to establish rate base by using the fair value of the

[1] The Commission's Order establishing this rulemaking proceeding set March 16, 2020, as the deadline for the filing of petitions to intervene. No party has objected to the AGO's late-filed notice of intervention and the Commission determines that no party will be prejudiced by allowing the AGO to participate at this stage in the proceeding.

utility property instead of original cost when acquiring an existing water or wastewater system owned by a municipality or county or an authority or district established under Chapter 162A of the General Statutes.

(b) Determination of Fair Value. –

(1) The fair value of a system to be acquired shall be based on three separate appraisals conducted by accredited, impartial valuation experts chosen from a list to be established by the Commission. The following shall apply to the valuation:

a. One appraiser shall represent the public utility acquiring the system, another appraiser shall represent the utility selling the system, and another appraiser shall represent the Public Staff of the Commission.

b. Each appraiser shall determine fair value in compliance with the uniform standards of professional appraisal practice, employing cost, market, and income approaches to assessment of value.

c. Fair value, for rate-making purposes under G.S. 62-133, shall be the average of the three appraisals provided for by this subsection.

d. The original source of funding for all or any portions of the water and sewer assets being acquired is not relevant to an evaluation of fair value.

(2) The acquiring public utility and selling utility shall jointly retain a licensed engineer to conduct an assessment of the tangible assets of the system to be acquired, and the assessment shall be used by the three appraisers in determining fair value.

(3) Reasonable fees, as determined by the Commission, paid to utility valuation experts, may be included in the cost of the acquired system, in addition to reasonable transaction and closing costs incurred by the acquiring public utility.

(4) The rate base value of the acquired system, which shall be reflected in the acquiring public utility's next general rate case for rate-making purposes, shall be the lesser of the purchase price negotiated between the parties to the sale or the fair value plus the fees and costs authorized in subdivision (3) of this subsection.

(5) The normal rules of depreciation shall begin to apply against the rate base value upon purchase of the system by the acquiring public utility.

(c) An application to the Commission for a determination of the rate base value of the system to be acquired shall contain all of the following:

(1) Copies of the valuations performed by the appraisers, as provided in subdivision (1) of subsection (b) of this section.

(2) Any deficiencies identified by the engineering assessment conducted pursuant to subdivision (2) of subsection (b) of this section and a five-year plan for prudent and necessary infrastructure improvements by the acquiring entity.

(3) Projected rate impact for the selling entity's customers for the next five years.
(4) The averaging of the appraisers' valuations, which shall constitute fair value for purposes of this section.
(5) The assessment of tangible assets performed by a licensed professional engineer, as provided in subdivision (2) of subsection (b) of this section.
(6) The contract of sale.
(7) The estimated valuation fees and transaction and closing costs incurred by the acquiring public utility.
(8) A tariff, including rates equal to the rates of the selling utility. The selling utility's rates shall be the rates charged to the customers of the acquiring public utility until the acquiring public utility's next general rate case, unless otherwise ordered by the Commission for good cause shown.

(d) Final Order. – If the application meets all the requirements of subsection (c) of this section, the Commission shall issue its final order approving or denying the application within six months of the date on which the application was filed. An order approving an application shall determine the rate base value of the acquired property for rate-making purposes in a manner consistent with the provisions of this section.

(e) Commission's Authority. – The Commission shall retain its authority under Chapter 62 of the General Statutes to set rates for the acquired system in future rate cases, and shall have the discretion to classify the acquired system as a separate entity for rate-making purposes, consistent with the public interest. If the Commission finds that the average of the appraisals will not result in a reasonable fair value, the Commission may adjust the fair value as it deems appropriate and in the public interest.

(f) The Commission shall adopt rules to implement this section.

PARTIES' COMMENTS AND PROPOSED RULES

The Companies' Petition and Proposed Rules

In their petition, the Companies detail their view of the purpose of the Fair Value Statute and propose the adoption of Commission Rule R7-41 for water utilities and Rule R10-28 for sewer utilities, in the form attached to its petition as Attachments B and C, respectively. In support of their petition, the Companies state that the purpose of the Fair Value Statute is to establish rules for determination of the "fair value," as opposed to the "reasonable original cost," for water or sewer utility property "used and useful" in service to customers that is purchased from one of the governmental providers specified in Chapter 162A of the General Statutes. The Companies further state that the determination of fair value is then used to calculate the rate base value of the acquired property, and that the Companies supported the enactment of this statute based on their understanding of the beneficial role that privately-owned water and wastewater companies can bring to customers and to some local government providers of water and wastewater service. The Companies argue that the "legacy statutory restriction to consideration of 'reasonable original cost' as the determinant of the value of rate base is an impediment to sensible private investment and to the extension of capable utilities management opportunities from the private sector to those units of government whose interests are better served by sale of their utilities properties." The Companies further argue that the Fair Value Statute establishes a mechanism by which willing sellers and willing buyers can overcome some of the barriers to negotiations, subject to independent action by the governmental providers, participation of the Public Staff, and the oversight of the Commission. The Companies emphasize that under the Fair Value Statute the Commission retains the authority to set rates for the acquired system in future rate cases, has the discretion to classify the acquired system as a separate rate entity in future rate cases, and has the authority to adjust the "fair value" as the Commission deems appropriate and in the public interest.

The Companies next comment that the enactment of the Fair Value Statute provides a path through which the interests of all customers can be advanced and safeguarded, the benefits of expanded rate base and economies of scale can be realized, and the expertise contained in these multi-state, professional, experienced providers can be focused on a wider number of North Carolina systems and customers, some of whom need the assistance. The Companies argue that the adoption of the requirements of the Fair Value Statute in the form of Commission rules will clarify uncertainties, modify the restrictions currently contained in the recognition of "reasonable original cost" as the primary valuation tool, and allow the carefully supervised development of this market in North Carolina with safeguards to protect those interests that are served by regulatory oversight.

The Companies then provide a detailed summary of their proposed rules. The Companies state that paragraph (a) of each rule provides the scope and purpose of the rule, paragraph (b) of each rule provides definitions of terms used in the rules, and paragraph (c) of each rule deals with the regulated utility's option to elect "fair value" calculation of rate base as opposed to using the "original cost." The Companies further summarize that paragrapb (d) in each rule addresses "Utility Valuation Experts" and the Commission's responsibility to maintain a list of these experts, paragraph (e) of each rule defines the methodology for determination of "fair value," paragraph (f) of each rule defines the methodology for determination of "rate base," when using this acquisition mechanism, and paragraph (g) of each rule speaks to the utility's opportunity to recommend assignment of the purchased assets to a specific existing rate division or to a newly established separate rate division. Further, the Companies state that paragraph (h) of each rule addresses the regulatory process to be employed for determination both of "fair value" and "rate base," and paragraph (i) of each rule specifies the necessary components of and time for issuance of the Commission's final order.

In conclusion, the Companies argue that the adoption of rules that allow fair market valuation as a component of the determination of rate base for property purchased by a public utility from a governmental-owned system has the potential to "unleash a number of benefits in North Carolina." The Companies identify and outline these benefits as follows: (1) options for governmental entities and their customers to access service that is more compliant with health and environmental standards, is more efficiently provided, and is more reliable over the long run; (2) less reliance on government funded monies via the infusion of private capital that can help maintain, repair, and replace water and wastewater infrastructure; (3) additions to the customer base of currently regulated public utility providers that allows overhead to be allocated across more customers; (4) potential economies of scale that hold promise of benefits to all customers; and (5) enhanced efficiencies when the acquired governmental system is located near existing facilities owned and operated by the public utility.

The Public Staff's Comments

In its initial comments, the Public Staff comments that although there are similar statutes in other states the appraisal process for determining rate base authorized in the Fair Value Statute is new to North Carolina. The Public Staff notes that there is no such North Carolina statute for natural gas or electric utility systems, and further states that the Public Staff has not found rules for the fair value acquisitions of water or wastewater systems adopted in other states.

The Public Staff next comments that it recommends "necessary additions" to the Companies' proposed rules. In support of its comments, the Public Staff relies on a recent presentation by Dr. Janice A. Beecher, PhD, Director of the Institute of Public Utilities at Michigan State University, which is attached to the Public Staff's comments as Exhibit 3. The Public Staff highlights several statements from Dr. Beecher's presentation and notes that Dr. Beecher lists potential "mitigation measures" by regulators. The Public Staff emphasized several of these mitigation measures that they consider particularly meaningful for North Carolina.

The Public Staff next comments that replacements of water and wastewater utility plant can be extremely costly and lists five recent major projects where Aqua replaced water mains and services in aged water systems. Based on this list, the Public Staff calculates an increase in rate base that could average at least $7,561 per single-family equivalent (SFE), if a purchasing utility needs to replace water mains within the first five or 10 years after acquisition. The Public Staff states that the Fair Value Statute provides that the customer rates at closing shall be the selling government entity's rates, which shall remain until the acquiring public utility's next general rate case. The Public Staff further states that although this temporarily freezes the customer's rates, this provision makes the customers unaware of future significant rate increases and rate shock. To illustrate, the Public Staff uses what it describes as a plausible example of future rate shock that would result in a $647 increase in revenue requirement per SFE, equating to a $53.91 rate increase per month per SFE, not including debt costs.

The Public Staff recommends that the following additional sections be added to the Companies' proposed rules: engineering assessment requirements, discovery, customer notice, intervention, burden of proof, public interest, rate division assignment, and payment of Public Staff utility valuation expert. The Public Staff then details its view on each of these additional sections that it proposes to be added to the Companies' proposed rules.

Based on its comments the Public Staff requests that the Commission approve its recommended rules with the additional sections noted above and the deletion of section (g) entitled "Rate Division Assignment" from the Companies' proposed rules. In addition, the Public Staff requests that the Commission approve the Water and Wastewater Engineering Assessment Form Water Fair Value – 1, which is attached to its comments as Exhibit 2.

The Companies' Reply Comments

In their reply comments, the Companies state that they have reviewed the Public Staff's comments and additional rule provisions and that their position differs from that expressed by the Public Staff in its comments with respect to various issues of logic and policy. Notwithstanding these differences the Companies further state that they largely find the Public Staff's proposed rule additions to be acceptable and worthy of adoption by the Commission with some refinements. Thus, the Companies propose revisions to their initial proposed rules to incorporate the Public Staff's recommendations with certain revisions and clarifying language. Proposed rules reflecting these revisions are attached to the Companies' reply comments as attachments A and B.

The Companies then summarize their proposed revisions to the rules that they initially proposed. The Companies state that subsection (g) has been revised to focus on the acquiring utility's plans for integration of the acquired system's rates into an existing rate division and that this provision does not require the Commission to make a determination on future rate division assignment at the time the Commission makes decisions on the fair value application. However, the Companies further state that an identification of intent or path to rate consolidation can be valuable information from which to build a record upon which the Commission can determine the appropriate Rate Division alignment in the future. The Companies next state that subsection (j) was added to accommodate the Public Staff's request for a discovery process in the application proceeding, with modifications to accommodate a business-day schedule for responses to discovery, as well as allowing site visits in a format that avoids inter-jurisdictional conflicts. The Companies further state that utilization of utility valuation experts allows for an extended analysis beyond the Public Staff's internal resource reach.

The Companies next comment that subsections (k), (l), (o), and (p) were added to its proposed rules consistent with the Public Staff's recommended rule additions. Further, the Companies state that their revised subsection (m), addressing intervention procedure, is included as proposed by the Public Staff and modified to allow intervention by any person directly impacted by the proposed acquisition. Next, the Companies state that subsection (n) requires the Commission to support its conclusion with sufficient and appropriate findings and conclusions if it concludes that approval of an application is not in the public interest. The Companies argue that this information will be instructive to utilities and owners of public water and wastewater systems and stakeholders of such systems in supporting potential future applications. Lastly, the Companies state that subsection (q) adds language to the Public Staff's proposed rules to allow an exception from certain provisions of the "engineering assessment rule," which the Companies argue might require the applicant utility to file information that may not be applicable or available with reference to certain applications. The Companies further argue that this will minimize unnecessary efforts to identify or clarify information that cannot be identified or is not relevant to the proposed application.

In conclusion, the Companies request that the Commission adopt the Companies' revised proposed rules attached to its reply comments and the Water and Wastewater Fair Value Engineering Assessment Form, Water Fair Value -1 as the template for the Licensed Engineer's Assessment, with the condition that information that is not applicable or readily available will be excluded. The Companies reiterate their position that adoption of rules that allow fair value as a component of the determination of rate base, when a regulated water or wastewater provider purchases a governmental-owned system, has the potential to unleash a number of benefits in North Carolina. The Companies restate the benefits that they believe will result from doing so as they did in their initial comments.

The AGO's Reply Comments

In its reply comments the AGO emphasizes the importance of incorporating adequate safeguards into the rules implementing the Fair Value Statute. The AGO states that it supports the Public Staff's recommendations. The AGO further states that safeguards are needed to avoid the burdensome rate increases documented in other states when fair market value legislation was adopted, that the Commission's successful oversight of applications for use of fair market valuation is important to mitigate the upward pressure on rates that is likely to occur, and that the rule modifications that have been recommended by the Public Staff will assist the Commission by improving the review process.

The AGO then provides background on the "fair market value approach" citing the presentation by Dr. Beecher that was included with the Public Staff's comments and an article from the Washington Post titled *Towns sell their public water systems – and come to regret it.* The AGO then notes several requirements of the Fair Value Statute and states that despite safeguards that should result from these statutory provisions, the use of fair market value poses practical concerns. The AGO further states that two of the three appraisals will be performed for the buyer and seller, and unlike many sales both have an interest in obtaining a high appraisal.

The AGO next comments that the Commission has been provided three significant tools in the Fair Value Statute to protect North Carolina consumers from unreasonable rate increases: (1) the Commission is authorized to adjust the fair value determined by the three appraisers if it finds that the average will not result in a reasonable fair value that is appropriate and in the public interest; (2) the Commission may classify the acquired system as a separate entity for ratemaking purposes; and (3) the Commission may deny the application. The AGO argues that the review process that is established by the rules adopted in this proceeding will have an important and lasting impact as it will establish the rate base value of the acquired property for rate-making purposes.

The AGO then outlines the Public Staff's comments and recommendations as offering the Commission valuable assistance in several ways. In closing, the AGO expresses support for the Public Staff's recommendations and argues that implementing safeguards and supervising the application process carefully will be critical to protecting customers form excessive rate increases as applications are filed for the use of fair market valuation.

DISCUSSION AND CONCLUSIONS

The Commission has carefully reviewed and considered the comments and proposed rules filed in this proceeding. Based upon that review, the Commission determines that the parties have reached agreement on rule provisions that are a reasonable means of implementing the Fair Value Statute. The Commission, therefore, concludes that much of the substantive provisions the parties proposed should be incorporated into the rules implementing N.C.G.S. § 62-133.1A. As discussed further below, however, the Commission further determines that the rules proposed by the parties are unnecessarily repetitive of provisions included in the Fair Value Statute and lack conformity with the format and level of detail included in the most recently adopted rules in Chapter 7 and Chapter 10 of the Commission's Rules and Regulations. Therefore, the rules that the Commission will adopt, while incorporating much of the substantive provisions proposed by the parties, are streamlined and reorganized. In addition, the Commission determines that the Public Staff has proposed an appropriate form for use in the engineering assessment of water and wastewater systems sought to be acquired and will adopt this form as a template for the engineer's assessment. Consistent with the Companies' comments and as is implied by the term "template," information that is not relevant to the assessment of a specific system need not be included and additional information that is relevant should be included as an attachment or addendum to the assessment form. Although not proposed by the parties, the Commission further determines that a form application would be helpful in administering proceedings pursuant to N.C.G.S. § 62-133.1A. Therefore, the Commission will adopt a form application and a modified version of the Public Staff's proposed Fair Value Engineering Assessment Form and incorporate these forms into the appendix to Chapters R7 and R10 of the Commission's Rules and Regulations. The Commission notes that the two rules adopted in this Order are substantively similar, although applicable in the contexts of the acquisition of water systems and wastewater systems, respectively, and that the Commission will discuss together the provisions of the two rules and the conclusions reached in adopting these rules below.

Paragraph (a) of the rules adopted in this Order sets out the scope of the rules. The Commission concludes that these rules should focus on the procedural and filing requirements for implementing N.C.G.S. § 62-133.1A and will therefore adopt a streamlined version of the paragraph (a) proposed by the parties. Reflecting this conclusion, the Commission declines to adopt the more substantive provisions proposed by the parties related to the method of calculation of rate base. The method of calculating rate base is sufficiently detailed in N.C.G.S. § 62-133.1A, and may be further refined in the course of considering an application filed pursuant to the statute and these rules. The Commission concludes that it is unnecessary to recite these statutory provisions in the rules adopted in this Order.

Paragraph (b) of the rules adopted in this Order sets out the defined terms used in the rules. Consistent with the Commission's determination to adopt more streamlined rules than those proposed by the parties, the Commission will decline to adopt definitions of terms that are adequately defined in Chapter 62 or elsewhere in the General Statutes. The Commission further concludes that the parties' proposed term "Chapter 162 Utility" is less precise than appropriate because municipally-owned water systems are operated pursuant to Chapter 160A of the General Statutes and county-owned water systems are operated pursuant to Chapter 153A. Instead, the Commission will adopt and make use of the defined term "Local Government Utility" to mean an existing water or wastewater system owned by a municipality, county, or an authority or district established under Chapter 162A of the General Statutes. This defined term adopts a similar approach to the definition of "unit of local government" as provided at N.C.G.S. § 160A-30(h), although that term is broader than the defined term "Local Government Utility" that the Commission will adopt in these rules. Finally, the Commission will adopt a modified version of the term "Professional Engineer" that requires the engineer conducting the utility assessment to be licensed by the North Carolina State Board of Examiners for Engineers and Surveyors, including those who may be licensed by comity or endorsement pursuant to N.C.G.S. § 89C-13(a2). The Commission concludes that this modification tends to harmonize the general term "licensed engineer," used in N.C.G.S. § 62-133.1A with the general prohibition on the practice of engineering by a person who has not been duly licensed. *See* N.C.G.S. § 89C-2.

The Commission declines to adopt the parties' proposed paragraph (c) as unnecessary and unduly repetitive of requirements provided elsewhere in the rules and implied by the filing of the application itself. However, portions of the parties' proposed paragraph (c) are incorporated in paragraph (d) that the Commission adopts, as discussed further below.

The paragraph (c) that the Commission will incorporate into the rules adopted in this Order generally reflect the parties' proposed paragraph (d) to implement the requirement of N.C.G.S. § 62-133.1A(b)(1) that the Commission maintain a list of accredited, impartial valuation experts. The Commission, in its discretion, will incorporate certain refinements to the provisions related to implementing this requirement. Under the rules adopted in this Order, the Commission will maintain the list of valuation experts in an open generic docket, Docket No. W-100, Sub 60A, where the Commission will receive applications from such persons and undertake appropriate administrative actions to ensure that these persons are initially qualified and continue to qualify to conduct utility valuations for the purpose of N.C.G.S. § 62-133.1A. The procedures used to maintain the list of valuation experts will be further detailed in a forthcoming order issued in Docket No. W-100, Sub 60A.

The paragraph (d) that the Commission will incorporate into the rules adopted in this Order reflects that the utility's election to establish rate base using fair value is made by the filing of an application pursuant to N.C.G.S. § 62-133.1A and the rules adopted in this Order. Implicit in this election is that the calculation of rate base attributable to the system to be acquired will not be based on the original cost, as authorized pursuant to N.C.G.S. § 62-133.1A. The Commission concludes that it is unnecessary to recite this statutory provision in the rules adopted in this Order. Further, and as noted above, the Commission determines that a form application will promote efficiency in these proceedings. The Commission will, therefore, adopt a form application as part of the appendix to Chapter R7 and R10 of the Commission's Rules and Regulations and require the use of this form in making an application pursuant to N.C.G.S. § 62-133.1A and the rules adopted in this Order. In addition, and as reflected in the form application, the Commission will require as part of the application a narrative explanation of the object and purposes desired and of the public interest served by the acquisition, and the Commission will preserve the option of requiring any other information as a specific case may require to facilitate the Commission's consideration of all relevant issues related to the acquisition and election to determine rate base based upon the fair value of the property acquired. Finally, the Commission will require that the application be accompanied by the testimony of the utility's president or another person employed by the utility who is personally familiar with the contents thereof and who verifies that the contents of the application are true and accurate. These requirements generally reflect rule provisions proposed by the parties in a more streamlined format focusing on procedural and filing requirements.

Consistent with the Commission's intent to adopt more streamlined rules that focus on procedural and filing requirements, the Commission declines to adopt substantive provisions proposed by the parties related to the methodology for determination of fair value (the parties' proposed paragraph (e)), and the methodology for determination of rate base (the parties' proposed paragraph (f)). These matters, the Commission concludes, are sufficiently addressed in the provisions of N.C.G.S. § 62-133.1A and need not be recited in the rules adopted in this Order. Further, these matters will develop in greater granularity as the Commission reviews applications made pursuant to the Fair Value Statute and the rules adopted in this Order on a case-by-case basis.

The Commission will incorporate paragraph (e) in the rules adopted in this Order to detail the procedure upon receipt of the application. The paragraph (e) that the Commission will incorporate into the rules adopted in this Order is a more streamlined version of the parties' proposed paragraph (h). Much of the required information proposed by the parties to be enumerated in their proposed paragraph (h), will be furnished in the required form application that the Commission adopts in this Order. This obviates the need to include rule provisions detailing these requirements and supports the Commission's broader intent to adopt a more streamlined version of the rules implementing the Fair Value Statute. In furtherance of the goal of deciding these matters within the statutory time period of six months from the filing of the application, *see* N.C.G.S. § 62-133.1A(d), the Commission will require the Public Staff to file and serve on the applicant a recommendation regarding whether the application is complete within ten days of the filing thereof. Given that the Public Staff will be involved in selecting an appraiser of the value of the system to be acquired and that appraiser will make use of the engineer's assessment of the system, the Commission expects that the Public Staff will be aware of the contents of the application by the purchasing utility prior to its filing. The Commission also expects that the utility will cooperate with the Public Staff to facilitate an efficient review of the application. Thus, the requirement for the Public Staff to provide a recommendation to the Commission will be minimally burdensome and should be achievable in most cases within the ten days required by the rules that the Commission adopts in this Order. When the Commission receives the Public Staff's recommendation and determines that the application is complete, then the Commission will promptly issue an order establishing procedural deadlines and discovery guidelines and requiring the utility to provide notice of the pending application to the customers of the Local Government Utility. Addressing these matters by Commission order obviates the need to incorporate the Public Staff's proposed paragraphs (j) (related to discovery), (k) (related to scheduling an evidentiary hearing), (l) (related to requiring customer notice), and (m) (related to allowing interested persons to intervene). Therefore, the Commission declines to adopt these proposed rule provisions.

Regarding the question of future rate division assignment of the customers served by the acquired system, the Commission will adopt a modified version of the parties' proposed paragraph (g). The Commission agrees with the parties that it is appropriate to reflect in the rules adopted in this order that N.C.G.S. § 62-133.1A(c)(8) requires that these customers be charged rates equivalent to those charged by the acquired governmental utility until the acquiring public utility's next general rate case proceeding, unless otherwise ordered by the Commission for good cause shown. The Commission will require the submittal of a tariff reflecting these rates as a part of the public utility's application pursuant to N.C.G.S. § 62-133.1A and the rules adopted in this Order. The Commission agrees with the parties that the application should include a statement about the public utility's future plans for integrating the acquired system into an existing rate division. Consistent with the Commission's effort to streamline the rules adopted in this Order, the rules make clear that the decision about whether and how to integrate the acquired water or wastewater system into an existing rate division is preserved for the Commission's consideration in the course of the public utility's next general rate case.

The Commission will also incorporate a modified version of the parties' proposed paragraph (i) detailing the matters that are to be specifically decided in the Commission's final order on the application. These matters include determination of the rate base value of the acquired system (which may be calculated as provided in N.C.G.S. § 62-133.1A(b) or pursuant to the Commission's authority to adjust that value pursuant to N.C.G.S. § 62-133.1A(e)), providing for the inclusion of certain costs eligible to be included in the rate base value of the acquired system, requiring the application of the normal rules of depreciation against the rate base value from the date of the purchase of the system (as required by N.C.G.S. § 62-133.1A(b)(5)), and the establishment of a new tariff for the provision of service to the customers in the acquired service territory.

The Commission agrees with the parties that the burden of proof is appropriately on the acquiring utility in all respects in the proceeding on the utility's application and for demonstrating that the acquisition of the Local Government Utility is in the public interest. Therefore, the Commission will incorporate the parties' proposed paragraph (o), although in the rules that the Commission adopts in this Order, this provision has been reorganized as paragraph (h).

The Commission also agrees that the Public Staff's proposed paragraphs related to payment for the Public Staff's utility valuation expert should be incorporated into the rules adopted in this Order. Therefore, the Commission will adopt paragraphs (i) as proposed by the Public Staff.

Finally, the Commission further agrees with the Public Staff that the use of an engineering assessment form would be helpful in administering these rules. Therefore, the Commission will adopt a Fair Value Engineering Assessment Form as part of the appendices to Chapters R7 and R10 of the Commission's Rules and Regulations.

Based upon the foregoing and the entire record herein, the Commission concludes that Commission Rule R7-41 and Commission Rule R10-28 as reflected in the appendices A and B, respectively, to this Order should be adopted pursuant to N.C.G.S. § 62-133.1A(f). A redline comparison of the rules adopted and the rules proposed by the parties is included for convenience at appendices C and D. Further, the Commission concludes that Form FV1, Application for Determination of Fair Value of Utility Assets Pursuant to N.C.G.S. § 62-133.1A, and Form FV1(a), Fair Value Engineering Assessment Form, should be adopted and required for use in any proceeding instituted before the Commission by the filing of an application pursuant to N.C.G.S. § 62-133.1A and the rules adopted in this Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of December, 2020.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

APPENDIX A
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Rule R7-41. PROCEDURE FOR DETERMINING FAIR VALUE AND ESTABLISHING RATE BASE FOR ACQUISITIONS OF GOVERNMENT-OWNED WATER SYSTEMS

(a) Scope of Rule.—This Rule provides the procedural and filing requirements for the determination of the value of utility property for ratemaking purposes applicable when a utility acquires an existing water system owned by a municipality or county, or an authority or district established under Chapter 162A of the General Statutes, and the utility makes an election pursuant to G.S. 62-133.1A(a) to establish its rate base associated with the acquisition by using the fair value of the acquired property instead of original cost.

(b) Definitions.

(1) "Local Government Utility" means an existing water system owned by a municipality, county, or an authority or district established under Chapter 162A of the General Statutes.

(2) "Rate Division" means a separate rate schedule of a water utility for one or more established customer service areas.

(3) "Utility Valuation Expert" means a person qualified as an expert in the appraisal of utility plant whose proficiency is demonstrated and established pursuant to subsection (c) of this Rule.

(4) "Professional Engineer" means a person who has been duly licensed by the North Carolina State Board of Examiners for Engineers and Surveyors established by Chapter 89C of the General Statutes, including those persons who may be licensed by comity or endorsement.

(5) "Asset Purchase Agreement" means a contract for the sale of an existing water system between a water utility, as buyer, and a Local Government Utility, as seller, which is to be valued for purposes of rate base. The Asset Purchase Agreement shall reflect the price negotiated between the Public Utility purchaser and the Local Government Utility.

(c) Establishment of List of Utility Valuation Experts.—The Commission shall establish a generic proceeding in Docket No. W-100, Sub 60A for the purpose of creating and maintaining a list of accredited, impartial Utility Valuation Experts as required pursuant to G.S. 62-133.1A(b). A person seeking to become a Utility Valuation Expert shall apply to the Commission by furnishing the following:

(1) a demonstration of the person's education and experience specific to providing valuations and appraisals of utility plant, as differentiated from other types of appraisals, such as for real estate;

(2) a written attestation that a Utility Valuation Expert owes a fiduciary duty to provide a thorough, objective, and fair valuation;

(3) a demonstration of financial and technical fitness, such as through production of professional licenses, technical certifications, and names of

current or past clients with a description of dates and types of services provided;

(4) a demonstration of adequate utility valuation and appraisal experience to support the Commission's decision to consider these persons or entities as experts in this field;

(5) a statement that the Utility Valuation Expert will make use of the assessment of the tangible assets of the system to be acquired, which assessment shall be from a Professional Engineer jointly retained by the utility and the Local Government Utility and make use of the Water and Wastewater Fair Value Engineering Assessment Form included in the Appendix to this Chapter as a template for the engineer's assessment;

(6) a statement that the Utility Valuation Expert will comply with the requirements of G.S. 62-133.1A in conducting their appraisal, including that the Utility Valuation Expert shall appraise the subject property in compliance with the uniform standards of professional appraisal practice, employing cost, market, and income approaches to assessment of value; and

(7) any other information as required by the Commission.

(d) Application for Election to Establish Rate Base Using Fair Value.—A water utility may elect to establish rate base using the fair value of the utility property acquired from a Local Government Utility by filing with the Commission an application pursuant to G.S. 62-133.1A and this Rule. The form of the application shall be as provided in the Appendix to this Chapter. In addition to providing the information required pursuant to G.S. 62-133.1A in the completed application form, the application shall contain a narrative explanation of the object and purposes desired by the application and how the public interest is served by the acquisition, along with any other information required by the Commission. The application shall be accompanied by the testimony of the acquiring utility's president or another person employed by the utility who is personally familiar with the contents thereof and who verifies that the contents of the application are true and accurate.

(e) Procedure upon receipt of Application.—Contemporaneous with the filing of an application with the Commission pursuant to G.S. 62-133.1A and this Rule, the utility shall serve a copy of the application on the Public Staff. The Public Staff shall review the application and no later than ten days after the application is filed, the Public Staff shall file with the Commission and serve upon the applicant a recommendation regarding whether the application is complete or identify any deficiencies noted. If the Commission determines that the application is incomplete as submitted, the utility will be required to file the omitted information.

Once the Commission determines that the application is complete, the Commission will promptly issue an order establishing procedural deadlines and discovery guidelines and requiring the utility to provide notice of the pending application to the customers of the Local Government Utility. If the Commission receives significant written complaints against the application, then the Commission will issue a further order setting

the application for hearing. The Commission will endeavor to schedule the hearings to be held within three months of the filing of the application to facilitate issuance of a final order within six months of the filing of a completed application as directed pursuant to G.S. 62-133.1A(d).

(f) Rate Division Assignment.—Pursuant to G.S. 62-133.1A(c)(8), service to customers in the service area of the Local Government Utility shall be under a tariff that includes rates equal to the rates of the selling utility until the utility's next general rate case, unless otherwise ordered by the Commission for good cause shown. An application filed pursuant to G.S. 62-133.1A and this Rule shall include a proposed tariff that reflects such rates and a statement as to whether the utility intends to propose in its next general rate case that the service area of the Local Government Utility be integrated into an existing Rate Division of the acquiring utility or be established as a new Rate Division. A determination as to whether the service area of the Local Government Utility should be integrated into an existing Rate Division or established as a new Rate Division shall be preserved for the Commission's consideration in the utility's next general rate case.

(g) Final Order on Application.—Consistent with the direction provided in G.S. 62-133.1A(d), the Commission will endeavor to issue a final order on the application filed pursuant to G.S. 62-133.1A and this Rule within six months of the filing of a completed application. The Commission's final order will resolve all substantive issues and, if the Commission determines that the Application should be approved, the Commission will specifically determine the rate base value of the acquired property for rate-making purposes in a manner consistent with G.S. 62-133.1A and the provisions of this Rule, as follows:

(1) Determination of Rate Base.—The rate base value of the acquired system shall be the lesser of the purchase price reflected in the Asset Purchase Agreement or the average of the three appraisals as required pursuant to G.S. 62-133.1A (b)(1), unless the Commission specifically finds that the average of the appraisals will not result in a reasonable fair value, in which case the Commission may adjust the fair value pursuant to G.S. 62-133.1A(e) as it deems appropriate and in the public interest;

(2) Certain Costs Eligible to be Included in Rate Base Value.—Consistent with G.S. 62-133.1A(b), the Commission will allow the inclusion of the costs of the engineering assessment, transaction and closing costs incurred by the utility, and fees paid to Utility Valuation Experts, including fees paid by the acquiring utility to a Utility Valuation Expert that represents the Public Staff, in the rate base value of the acquired system upon a finding that those costs were reasonably and prudently incurred;

(3) Depreciation.—The Commission will require the utility to apply the normal rules of depreciation against the rate base value from the date of the purchase of the system; and

(4) Tariffs.—The Commission will approve the establishment of a new tariff for the provision of water service to customers in the acquired service territory,

which shall also determine whether the acquired service territory will be treated as a separate Rate Division.

(h) Burden of Proof.—The utility shall have the burden of proof regarding all aspects of the proceeding on an application filed pursuant to G.S. 62-133.1A and this Rule, and for demonstrating that the acquisition of the Local Government Utility is in the public interest.

(i) Payment of Fees for Public Staff Utility Valuation Expert.—The acquiring utility shall pay the fees of the Utility Valuation Expert that represents the Public Staff whether the Commission approves the application, denies the application, or if the acquiring utility withdraws the application.

Rule R 10-28. PROCEDURE FOR DETERMINING FAIR VALUE AND ESTABLISHING RATE BASE FOR ACQUISITION OF GOVERNMENT-OWNED WASTEWATER SYSTEMS

(a) Scope of Rule.—This Rule provides the procedural and filing requirements for the determination of the value of utility property for ratemaking purposes applicable when a utility acquires an existing wastewater system owned by a municipality or county, or an authority or district established under Chapter 162A of the General Statutes, and the utility makes an election pursuant to G.S. 62-133.1A(a) to establish its rate base associated with the acquisition by using the fair value of the acquired property instead of original cost.

(b) Definitions.

(1) "Local Government Utility" means an existing wastewater system owned by a municipality, county, or an authority or district established under Chapter 162A of the General Statutes.

(2) "Rate Division" means a separate rate schedule of a wastewater utility for one or more established customer service areas.

(3) "Utility Valuation Expert" means a person qualified as an expert in the appraisal of utility plant whose proficiency is demonstrated and established pursuant to subsection (c) of this Rule.

(4) "Professional Engineer" means a person who has been duly licensed by the North Carolina State Board of Examiners for Engineers and Surveyors established by Chapter 89C of the General Statutes, including those persons who may be licensed by comity or endorsement.

(5) "Asset Purchase Agreement" means a contract for the sale of an existing wastewater system between a wastewater utility, as buyer, and a Local Government Utility, as seller, which is to be valued for purposes of rate base. The Asset Purchase Agreement shall reflect the price negotiated between the Public Utility purchaser and the Local Government Utility.

(c) Establishment of List of Utility Valuation Experts.—The Commission shall establish a generic proceeding in Docket No. W-100, Sub 60A for the purpose of creating and maintaining a list of accredited, impartial Utility Valuation Experts as required pursuant to G.S. 62-133.1A(b). A person seeking to become a Utility Valuation Expert shall apply to the Commission by furnishing the following:

(1) a demonstration of the person's education and experience specific to providing valuations and appraisals of utility plant, as differentiated from other types of appraisals, such as for real estate;

(2) a written attestation that a Utility Valuation Expert owes a fiduciary duty to provide a thorough, objective, and fair valuation;

(3) a demonstration of financial and technical fitness, such as through production of professional licenses, technical certifications, and names of

current or past clients with a description of dates and types of services provided;

(4) a demonstration of adequate utility valuation and appraisal experience to support the Commission's decision to consider these persons or entities as experts in this field;

(5) a statement that the Utility Valuation Expert will make use of the assessment of the tangible assets of the system to be acquired, which assessment shall be from a Professional Engineer jointly retained by the utility and the Local Government Utility and make use of the Water and Wastewater Fair Value Engineering Assessment Form included in the Appendix to this Chapter as a template for the engineer's assessment;

(6) a statement that the Utility Valuation Expert will comply with the requirements of G.S. 62-133.1A in conducting their appraisal, including that the Utility Valuation Expert shall appraise the subject property in compliance with the uniform standards of professional appraisal practice, employing cost, market, and income approaches to assessment of value; and

(7) any other information as required by the Commission.

(d) Application for Election to Establish Rate Base Using Fair Value.—A wastewater utility may elect to establish rate base using the fair value of the utility property acquired from a Local Government Utility by filing with the Commission an application pursuant to G.S. 62-133.1A and this Rule. The form of the application shall be as provided in the Appendix to this Chapter. In addition to providing the information required pursuant to G.S. 62-133.1A in the completed application form, the application shall contain a narrative explanation of the object and purposes desired by the application and how the public interest served by the acquisition, along with any other information required by the Commission. The application shall be accompanied by the testimony of the acquiring utility's president or another person employed by the utility who is personally familiar with the contents thereof and who verifies that the contents of the application are true and accurate.

(e) Procedure upon receipt of Application.—Contemporaneous with the filing of an application with the Commission pursuant to G.S. 62-133.1A and this Rule, the utility shall serve a copy of the application on the Public Staff. The Public Staff shall review the application and no later than ten days after the application is filed, the Public Staff shall file with the Commission and serve upon the applicant a recommendation regarding whether the application is complete or identify any deficiencies noted. If the Commission determines that the application is incomplete as submitted, the utility will be required to file the omitted information.

Once the Commission determines that the application is complete, the Commission will promptly issue an order establishing procedural deadlines and discovery guidelines and requiring the utility to provide notice of the pending application to the customers of the Local Government Utility. If the Commission receives significant written complaints against the application, then the Commission will issue a further order setting

the application for hearing. The Commission will endeavor to schedule the hearings to be held within three months of the filing of the application to facilitate issuance of a final order within six months of the filing of a completed application as directed pursuant to G.S. 62-133.1A(d).

(f) Rate Division Assignment.—Pursuant to G.S. 62-133.1A(c)(8), service to customers in the service area of the Local Government Utility shall be under a tariff that includes rates equal to the rates of the selling utility until the utility's next general rate case, unless otherwise ordered by the Commission for good cause shown. An application filed pursuant to G.S. 62-133.1A and this Rule shall include a proposed tariff that reflects such rates and a statement as to whether the utility intends to propose in its next general rate case that the service area of the Local Government Utility be integrated into an existing Rate Division of the acquiring utility or be established as a new Rate Division. A determination as to whether the service area of the Local Government Utility should be integrated into an existing Rate Division or established as a new Rate Division shall be preserved for the Commission's consideration in the utility's next general rate case.

(g) Final Order on Application.—Consistent with the direction provided in G.S. 62-133.1A(d), the Commission will endeavor to issue a final order on the application filed pursuant to G.S. 62-133.1A and this Rule within six months of the filing of a completed application. The Commission's final order will resolve all substantive issues and, if the Commission determines that the Application should be approved, the Commission will specifically determine the rate base value of the acquired property for rate-making purposes in a manner consistent with G.S. 62-133.1A and the provisions of this Rule, as follows:

(1) Determination of Rate Base.—The rate base value of the acquired system shall be the lesser of the purchase price reflected in the Asset Purchase Agreement or the average of the three appraisals as required pursuant to G.S. 62-133.1A (b)(1), unless the Commission specifically finds that the average of the appraisals will not result in a reasonable fair value, in which case the Commission may adjust the fair value pursuant to G.S. 62-133.1A(e) as it deems appropriate and in the public interest;

(2) Certain Costs Eligible to be Included in Rate Base Value.—Consistent with G.S. 62-133.1A(b), the Commission will allow the inclusion of the costs of the engineering assessment, transaction and closing costs incurred by the utility, and fees paid to Utility Valuation Experts, including fees paid by the acquiring utility to a Utility Valuation Expert that represents the Public Staff, in the rate base value of the acquired system upon a finding that those costs were reasonably and prudently incurred;

(3) Depreciation.—The Commission will require the utility to apply the normal rules of depreciation against the rate base value from the date of the purchase of the system; and

(4) Tariffs.—The Commission will approve the establishment of a new tariff for the provision of wastewater service to customers in the acquired service

territory, which shall also determine whether the acquired service territory will be treated as a separate Rate Division.

(h) Burden of Proof.—The utility shall have the burden of proof regarding all aspects of the proceeding on an application filed pursuant to G.S. 62-133.1A and this Rule, and for demonstrating that the acquisition of the Local Government Utility is in the public interest.

(i) Payment of Fees for Public Staff Utility Valuation Expert. —The acquiring utility shall pay the fees of the Utility Valuation Expert that represents the Public Staff whether the Commission approves the application, denies the application, or if the acquiring utility withdraws the application.

~~R7-41-1 Determination of Fair Value and Establishment of Rate Base for Acquisitions of Governmental-Owned Water Systems~~

Rule R7-41. PROCEDURE FOR DETERMINING FAIR VALUE AND ESTABLISHING RATE BASE FOR ACQUISITIONS OF GOVERNMENT-OWNED WATER SYSTEMS

(a) Scope of Rule.— .—This ~~rule~~Rule provides the ~~process for~~ procedural and filing requirements for the determination of the "~~fair~~ value" of ~~used and useful~~ utility property ~~purchased by a regulated Public Utility from a qualifying unit of government, for purposes of inclusion in a regulated water utility's rate base. It also sets forth the method of calculation of rate base,~~ for ratemaking purposes~~,~~. applicable when a utility acquires an existing water system owned by a municipality or county, or an authority or district established under Chapter 162A of the General Statutes, and the utility makes an election pursuant to G.S. 62-133.1A(a) to establish its rate base associated with the acquisition by using the "fair value" ~~methodology. Determination and use of fair value for rate base calculation is an alternative to the use oreasonable~~ of the acquired property instead of original cost~~.~~.

~~(b)~~ Definitions.~~ As used in this rule:~~

~~(1) Public~~ "Local Government Utility" means ~~a~~an existing water ~~utility as defined in G.S. 62-3(23)a.2 and regulated by the North Carolina Utilities Commission (Commission).~~

~~(2) Chapter 162A Utility means an existing water or wastewater~~ system owned by a ~~governmental entity —~~a municipality, county, or an authority or district~~,~~ established under Chapter 162A of the General Statutes.

~~(3)~~ (2) "Rate Division" means a separate ~~tariff~~rate schedule of a ~~Public Utility~~water utility for one or more established customer service areas.

~~(4)~~ (3) "Utility Valuation Expert" ~~is~~ means a person qualified as an expert in the appraisal of utility plant~~,~~ whose proficiency is demonstrated and established ~~according~~pursuant to ~~the provisions of~~ subsection ~~(d), below, and who, as an individual or a firm, qualifies to be maintained on a list established by the Commission, pursuant to G.S. 62-133.1A.(b)(1).~~ (c) of this Rule.

~~(5) Licensed~~ (4) "Professional Engineer" ~~is a Professional Engineer,~~ means a person who has been duly licensed by the North Carolina State Board of Examiners for Engineers and Surveyors ~~or an equivalent state licensing agency.~~ established by Chapter 89C of the General Statutes, including those persons who may be licensed by comity or endorsement.

~~(6)~~ 5) "Asset Purchase Agreement" ~~is the~~means a contract for the sale of ~~the utility property~~ an existing water system between a water utility, as buyer, and a Local Government Utility, as seller, which is to be valued for purposes of rate base. The Asset Purchase Agreement ~~reflects~~shall reflect the price negotiated between the Public Utility purchaser and the ~~Chapter 162A~~Local Government Utility.

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~~by filing an Application for Determination of Fair Value and Rate Base and Approval of Transfer with the Commission.~~

~~(d) Establishment of list of~~ (c) Establishment of List of Utility Valuation Experts~~.~~ .—The Commission shall establish ~~and maintain~~a generic proceeding in Docket No. W-100, Sub 60A for the purpose of creating and maintaining a list of accredited, impartial Utility Valuation Experts~~, from which the purchasing Public Utility, the selling Chapter 162A Utility, and the Public Staff shall each select for purposes of development of appraisals to use in determining fair value. To qualify for the list, a person or firm presenting themselves to the Commission for recognition as~~

as required pursuant to G.S. 62-133.1A(b). A person seeking to become a Utility Valuation Expert ~~must:~~ shall apply to the Commission by furnishing the following:

(1) ~~demonstrate~~ a demonstration of the person's education and experience ~~necessary for~~ specific to providing ~~utility~~ valuations and appraisals of utility plant, as differentiated from other types of appraisals, such as for real estate;

~~(2) attest in writing to~~(2) a written attestation that a Utility Valuation Expert owes a fiduciary duty to provide a thorough, objective, and fair valuation;

(3) ~~demonstrate~~ a demonstration of financial and technical fitness, such as through production of professional licenses, technical certifications, and/~~or~~ names of current or past clients with a description of dates and types of services provided; ~~and~~

(4) ~~demonstrate~~ a demonstration of adequate utility valuation and appraisal experience to support the ~~Commission's~~Commission's decision to consider these persons or entities as experts in this field~~.~~;

~~(e) Methodology for Determination of Fair Value.~~

~~(1) The acquiring Public Utility and seller/Chapter 162A Utility shall negotiate an Asset Purchase Agreement.~~

~~(2) The acquiring Public Utility and~~ (5) a statement that the ~~seller, a Chapter 162A Utility, shall jointly retain a Licensed Professional Engineer to conduct an~~Utility Valuation Expert will make use of the assessment of the tangible assets of the system to be acquired~~. The~~, which assessment shall be ~~used~~from a Professional Engineer jointly retained by the ~~three Utility Valuation Experts [who are selected as prescribed in subsection (3), below], in determining fair value, and shall ultimately be filed with the Application.~~

(3) ~~The Chapter 162A Utility,~~ utility and the ~~Public~~Local Government Utility, and make use of the ~~Public Staff shall each secure a written appraisal, or valuation, from persons or entities on~~ Water and Wastewater Fair Value Engineering Assessment Form included in the ~~Commission's list of Utility Valuation Experts.~~ Appendix to this Chapter as a template for the engineer's assessment;

(4) ~~Each~~(6) a statement that the Utility Valuation Expert will comply with the requirements of G.S. 62-133.1A in conducting their appraisal, including that the Utility Valuation Expert shall appraise the subject property in compliance with the uniform standards of professional appraisal practice, employing cost, market, and income approaches to assessment of value~~.~~; and

(5) (7) any other information as required by the Commission.

(d) Application for Election to Establish Rate Base Using Fair Value.—A water utility may elect to establish rate base using the fair value~~, for rate making purposes under G.S. 62-133, shall be the average~~ of the ~~three appraisals~~utility property acquired from a Local Government Utility by filing with the Commission an application pursuant to G.S. 62-133.1A and this Rule. The form of the application shall be as provided in the Appendix to this Chapter. In addition to providing the information required pursuant to G.S. 62-133.1A in the completed application form, the application shall contain a narrative explanation of the object and purposes desired by the application and how the public interest is served by the acquisition, along with any other information required by the Commission. The application shall be accompanied by the testimony of the acquiring utility's president or another person employed by the utility who is personally familiar with the contents thereof and who verifies that the contents of the application are true and accurate.

(e) Procedure upon receipt of Application.—Contemporaneous with the filing of an application with the Commission pursuant to G.S. 62-133.1A and this Rule, the utility shall serve a copy of the application on the Public Staff. The Public Staff shall review the application and no later than ten days after the application is filed, the Public Staff shall file with the Commission and serve upon the applicant a recommendation regarding whether the application is complete or identify any deficiencies noted. If the Commission determines that the application is incomplete as submitted, the utility will be required to file the omitted information.

Once the Commission determines that the application is complete, the Commission will promptly issue an order establishing procedural deadlines and discovery guidelines and requiring the utility to provide notice of the pending application to the customers of the Local Government Utility. If the Commission receives significant written complaints against the application, then the Commission will issue a further order setting the application for hearing. The Commission will endeavor to schedule the hearings to be held within three months of the filing of the application to facilitate issuance of a final order within six months of the filing of a completed application as directed pursuant to G.S. 62-133.1A(d).

(f) ~~Methodology for~~ Rate Division Assignment.—Pursuant to G.S. 62-133.1A(c)(8), service to customers in the service area of the Local Government Utility shall be under a tariff that includes rates equal to the rates of the selling utility until the utility's next general rate case, unless otherwise ordered by the Commission for good cause shown. An application filed pursuant to G.S. 62-133.1A and this Rule shall include a proposed tariff that reflects such rates and a statement as to whether the utility intends to propose in its next general rate case that the service area of the Local Government Utility be integrated into an existing Rate Division of the acquiring utility or be established as a new Rate

Division. A determination as to whether the service area of the Local Government Utility should be integrated into an existing Rate Division or established as a new Rate Division shall be preserved for the Commission's consideration in the utility's next general rate case.

(g) Final Order on Application.—Consistent with the direction provided in G.S. 62-133.1A(d), the Commission will endeavor to issue a final order on the application filed pursuant to G.S. 62-133.1A and this Rule within six months of the filing of a completed application. The Commission's final order will resolve all substantive issues and, if the Commission determines that the Application should be approved, the Commission will specifically determine the rate base value of the acquired property for rate-making purposes in a manner consistent with G.S. 62-133.1A and the provisions of this Rule, as follows:

~~(1)~~ Determination of Rate Base~~.~~—

~~(1)~~.— The rate base value of the acquired system~~, which shall be reflected in the acquiring Public Utility's next general rate case for rate-making purposes,~~ shall be the lesser of the purchase price ~~negotiated between the parties to the sale,~~ reflected in the Asset Purchase Agreement~~,~~ or the average of the three appraisals as required pursuant to G.S. 62-133.1A (b)(1), unless the Commission specifically finds that the average of the appraisals will not result in a reasonable fair value"~~plus the fees~~, in which case the Commission may adjust the fair value pursuant to G.S. 62-133.1A(e) as it deems appropriate and in the public interest;

(2) Certain Costs Eligible to be Included in Rate Base Value.—Consistent with G.S. 62-133.1A(b), the Commission will allow the inclusion of the costs ~~authorized in subsection (2) of this section, below.~~

(2) ~~As determined by the Commission, reasonable~~ of the engineering assessment, transaction and closing costs incurred by the utility, and fees paid to Utility Valuation Experts~~—~~, including ~~for the engineering assessment and reasonable transaction and closing costs incurred~~fees paid by the acquiring ~~Public~~utility to a Utility ~~may be included~~Valuation Expert that represents the Public Staff, in the ~~cost~~rate base value of the acquired system~~.~~ upon a finding that those costs were reasonably and prudently incurred;

(3) ~~The~~ Depreciation.—The Commission will require the utility to apply the normal rules of depreciation ~~shall begin to apply~~ against the rate base value ~~upon~~from the date of the purchase of the system~~ by the acquiring Public Utility.~~; and

~~(g) Rate Division Assignment.~~

~~(1) In any Application filed under G.S. 62-133.1A, the acquiring Public Utility shall state whether it plans in the future to propose that the service area of the customers of the Chapter 162A Utility being acquired should be integrated into an existing Rate Division.~~

~~(2) The acquiring Public Utility, in its next general rate case, shall propose whether the service area of the customers acquired from the Chapter 162A Utility should be integrated into an existing Rate Division of the Public Utility or should be established as a new Rate Division. If the recommendation is for integration into an existing Rate Division, the acquiring Public Utility shall recommend how the area is to be integrated, including any necessary tariff revisions, and shall have the burden of proof to demonstrate that such integration is in the public interest. If the recommendation is for establishment of a new Rate Division, the acquiring Public Utility shall include proposed tariffs or tariff revisions as part of its Application.~~

~~(h) Regulatory Application Process for Determination of Fair Value and of Rate Base. A Public Utility Application for Determination of Fair Value and Rate Base and Approval of Transfer, filed under these Rules, shall be signed and verified by the president or designated officer of the acquiring Public Utility and shall contain all of the following:~~

~~(1) explanation of the object and purposes desired and of the public interest served by the acquisition;~~

~~(2) copies of the appraisals or valuations performed by the three Utility Valuation Experts, of the engineering assessment, and of the Asset Purchase Agreement;~~

~~(3) a statement of any deficiencies identified by the engineering assessment, and a five-year plan for prudent and necessary infrastructure improvements;~~

~~(4) the projected rate impact for the customers of the selling Chapter 162A Utility for the next five years;~~

~~(5) a proposed tariff;~~

~~(6) any recommendations for Rate Division assignment of the customers of the Chapter 162A utility being acquired;~~

~~(7) a map of the service area for the system(s) being acquired;~~

~~(8) the total cost of obtaining the valuations, including the *estimated* valuation fees, engineering fees, and transaction and closing costs incurred by the acquiring Public Utility; and~~

~~(9) any other information required or relevant under G.S. 62-133.1A.(c).~~

~~(i) Final Order. If the Application meets the requirements of G.S. 62 -133.1A.(c), the Commission's order approving or denying the Application must be issued within six months of the date of filing of the Application, in accordance with G.S. 62-133.1A.(d). In an order approving an Application, the Commission shall include the following:~~

~~(1) A determination of the fair value and the rate base value, inclusive of costs delineated in subsection (h)(8) of this rule, of the acquired utility property for rate-making purposes;~~

~~(2) The Rate Division under which the acquired service area shall be served; and~~

~~(3) Approval of the necessary tariffs or tariff revisions.~~

~~(j) Discovery.~~

~~(1) All parties to the proceeding shall be permitted to serve (by hand delivery, facsimile or electronic delivery) data requests upon the selling Chapter 162A Utility, the purchasing Public Utility, the Public Staff, any Intervenor, the Licensed Professional Engineer, and/or one or more of the Utility Valuation Expert(s);~~

~~(2) The return date on each data request shall be ten business days. The party served with discovery shall have up to ten business days to file objections to the discovery request on an item by item basis; and~~

~~(3) Subject to the agreement of the selling Chapter 162A Utility, the Public Staff shall have authority to make site visits to the utility system.~~

~~(k) Evidentiary Hearing. If deemed appropriate, the Commission may schedule the Application for *evidentiary* hearing and require the prefiling of testimony.~~

~~(l) Customer Notice. The Commission *shall* require the selling Chapter 162A Utility to provide to each of its customers, by bill insert or first-class mail, a Commission-approved Customer Notice pursuant to a Commission-prescribed schedule.~~

~~(m) Intervention. Any customer of the selling Chapter 162A Utility, or a person having a demonstrated real and direct interest in the sale of the water and/or wastewater system to the purchasing Public Utility, may become a party to the Fair Value Purchase proceeding by filing a petition pursuant to Commission Rule R1-19. The Commission, in each Fair Value Purchase proceeding, shall set the deadline for filing a petition to intervene.~~

~~(n) Public Interest. If the Commission finds that the average of the appraisals will not result in a reasonable fair value, the Commission may adjust the fair value as it deems appropriate and in the public interest. The decision should be supported with appropriate and sufficient findings and conclusions.~~

~~(o) Burden of Proof. The acquiring Public Utility shall have the burden of proof in the Application proceeding. (p)~~ (4) Tariffs.—The Commission will approve the establishment of a new tariff for the provision of water service to customer in the acquired service territory, which shall also determine whether the acquired service territory will be treated as a separate Rate Division.

(h) Burden of Proof.—The utility shall have the burden of proof regarding all aspects of the proceeding on an application filed pursuant to G.S. 62-133.1A and this Rule, and for demonstrating that the acquisition of the Local Government Utility is in the public interest.

(i) Payment of Fees for Public Staff Utility Valuation Expert~~—~~.—The acquiring ~~Public~~ Utility utility shall pay the fees of the ~~Public Staff~~ Utility Valuation Expert ~~should~~that represents the Public Staff whether the Commission ~~deny the Application, or should~~ approves the application, denies the application, or if the acquiring ~~Public Utility withdraw the Application.~~

~~(q) Engineering Assessment. The Water and Wastewater Fair Value Engineering Assessment Form, Water Fair Value – 1, will be provided to the Licensed Professional Engineer prior to engineering review, and shall serve as~~ the ~~template for the engineer's assessment. Information requested on this guide shall only be included if it is applicable and readily available.~~

application.

~~R10-281 Determination of Fair Value and Establishment of Rate Base for Acquisitions of Governmental-Owned Sewer Systems~~

~~a)~~Rule R 10-28. PROCEDURE FOR DETERMINING FAIR VALUE AND ESTABLISHING RATE BASE FOR ACQUISITION OF GOVERNMENT-OWNED WASTEWATER SYSTEMS

(a) Scope of Rule~~.—~~.—This ~~rule~~Rule provides the ~~process for~~ procedural and filing requirements for the determination of the ~~fair~~ value of ~~used and useful~~ utility property ~~purchased by a regulated Public Utility from a qualifying unit of government, for purposes of inclusion in a regulated sewer utility's rate base. It also sets forth the method of calculation of rate base,~~ for ratemaking purposes, applicable when a utility acquires an existing wastewater system owned by a municipality or county, or an authority or district established under Chapter 162A of the General Statutes, and the utility makes an election pursuant to G.S. 62-133.1A(a) to establish its rate base associated with the acquisition by using the fair value ~~methodology. Determination and use~~ of ~~"fair value" for rate base calculation is an alternative to~~ the ~~use~~acquired property instead of ~~"reasonable~~ original cost~~."~~.

(b) Definitions.~~— As used in this rule:~~

(1) ~~Public~~ "Local Government Utility" means ~~a sewer utility as defined in G.S. 62-3(23)a.2 and regulated by the North Carolina Utilities Commission ("Commission").~~

~~(2) "Chapter 162A Utility" means~~ an existing ~~water or~~ wastewater system owned by a ~~governmental entity – a~~ municipality, county, or an authority or district~~,~~ established under Chapter 162A of the General Statutes.

~~(3)~~ 2) "Rate Division" means a separate ~~tariff~~rate schedule of a ~~Public Utility~~wastewater utility for one or more established customer service areas.

~~(4)~~ 3) "Utility Valuation Expert" ~~is~~ means a person qualified as an expert in the appraisal of utility plant~~,~~ whose proficiency is demonstrated and established ~~according~~pursuant to ~~the provisions of~~ subsection (~~d), below, and who, as an individual or a firm, qualifies to be maintained on a list established by the Commission, pursuant to G.S. 62-133.1A.(b)(1).~~c) of this Rule.

~~(5) Licensed~~ (4) "Professional Engineer" ~~is a Professional Engineer,~~ means a person who has been duly licensed by the North Carolina State Board of Examiners for Engineers and Surveyors ~~or an equivalent state licensing agency~~established by Chapter 89C of the General Statutes, including those persons who may be licensed by comity or endorsement.

(~~6)~~5) "Asset Purchase Agreement" ~~is the~~ means a contract for the sale of ~~the utility property~~ an existing wastewater system between a wastewater utility, as buyer, and a Local Government Utility, as seller, which is to be valued for purposes of rate base. The Asset Purchase Agreement ~~reflects~~shall reflect the price negotiated between the Public Utility purchaser and the ~~Chapter 162A~~Local Government Utility.

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~~(7) "Application for Determination of Fair Value and Rate Base and Approval of Transfer" ("Application") is the application to be filed with the Commission pursuant to G.S. 62-133.1(A).(c)~~

~~(c) Election by Acquiring Regulated Public Utility. A regulated Public Utility may elect to establish rate base, when purchasing qualifying utility property from a Chapter 162A Utility, by use of "fair value" instead of "reasonable original cost" by filing an Application for Determination of Fair Value and Rate Base and Approval of Transfer with the Commission.~~

~~(d) Establishment of list of "~~(c) Establishment of List of Utility Valuation Experts~~."~~ .—The Commission shall establish ~~and maintain~~a generic proceeding in Docket No. W-100, Sub 60A for the purpose of creating and maintaining a list of accredited, impartial Utility Valuation Experts~~, from which the purchasing Public Utility, the selling Chapter 162A Utility, and the Public Staff shall each select for purposes of development of appraisals to use in determining "fair value." To qualify for the list, a person or firm presenting themselves to the Commission for recognition as~~ as required pursuant to G.S. 62-133.1A(b). A person seeking to become a Utility Valuation Expert ~~must~~shall apply to the Commission by furnishing the following:

(1) ~~demonstrate~~ a demonstration of the person's education and experience ~~necessary for~~ specific to providing ~~utility~~ valuations and appraisals of utility plant, as differentiated from other types of appraisals, such as for real estate;

~~(2) attest in writing to~~ (2) a written attestation that a Utility Valuation Expert owes a fiduciary duty to provide a thorough, objective, and fair valuation;

(3) ~~demonstrate~~ a demonstration of financial and technical fitness, such as through production of professional licenses, technical certifications, and/~~or~~ names of current or past clients with a description of dates and types of services provided; ~~and~~

(4) ~~demonstrate~~ a demonstration of adequate utility valuation and appraisal experience to support the ~~Commission's~~Commission's decision to consider these persons or entities as experts in this field~~.~~;

~~(c) Methodology for Determination of Fair Value.—~~

~~(1) The acquiring Public Utility and seller/Chapter 162A Utility shall negotiate an Asset Purchase Agreement.~~

~~(2) The acquiring Public Utility and~~ (5) a statement that the ~~seller, a Chapter 162A Utility, shall jointly retain a Licensed Professional Engineer to conduct an~~ Utility Valuation Expert will make use of the assessment of the tangible assets of the system to be acquired~~. The~~, which assessment shall be ~~used~~from a Professional Engineer jointly retained by the ~~three Utility Valuation Experts [who are selected as prescribed in subsection (3), below], in determining fair value, and shall ultimately be filed with the Application.~~

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~~(3) The Chapter 162A Utility,~~ utility and the ~~Public~~Local Government Utility~~,~~ and make use of the ~~Public Staff shall each secure a written appraisal, or valuation, from persons or entities on~~ Water and Wastewater Fair Value Engineering Assessment Form included in the ~~Commission's list of Utility Valuation Experts.~~Appendix to this Chapter as a template for the engineer's assessment;

~~(4) Each~~(6) a statement that the Utility Valuation Expert will comply with the requirements of G.S. 62-133.1A in conducting their appraisal, including that the Utility Valuation Expert shall appraise the subject property in compliance with the uniform standards of professional appraisal practice; employing cost, market, and income approaches to assessment of value.; and

~~(5)~~ "(7) any other information as required by the Commission.

(d) Application for Election to Establish Rate Base Using Fair Value.—A wastewater utility may elect to establish rate base using the fair value~~," for rate-making purposes under G.S. 62-133, shall be the average~~ of the ~~three appraisals~~utility property acquired from a Local Government Utility by filing with the Commission an application pursuant to G.S. 62-133.1A and this Rule. The form of the application shall be as provided in the Appendix to this Chapter. In addition to providing the information required pursuant to G.S. 62-133.1A in the completed application form, the application shall contain a narrative explanation of the object and purposes desired by the application and how the public interest served by the acquisition, along with any other information required by the Commission. The application shall be accompanied by the testimony of the acquiring utility's president or another person employed by the utility who is personally familiar with the contents thereof and who verifies that the contents of the application are true and accurate.

(e) Procedure upon receipt of Application.—Contemporaneous with the filing of an application with the Commission pursuant to G.S. 62-133.1A and this Rule, the utility shall serve a copy of the application on the Public Staff. The Public Staff shall review the application and no later than ten days after the application is filed, the Public Staff shall file with the Commission and serve upon the applicant a recommendation regarding whether the application is complete or identify any deficiencies noted. If the Commission determines that the application is incomplete as submitted, the utility will be required to file the omitted information.

Once the Commission determines that the application is complete, the Commission will promptly issue an order establishing procedural deadlines and discovery guidelines and requiring the utility to provide notice of the pending application to the customers of the Local Government Utility. If the Commission receives significant written complaints against the application, then the Commission will issue a further order setting the application for ~~by this section.~~hearing. The Commission will endeavor to schedule the hearings to be held within three months of the filing of the application to facilitate issuance of a final order within six months of the filing of a completed application as directed pursuant to G.S. 62-133.1A(d).

~~(f) Methodology for~~ (f) Rate Division Assignment.—Pursuant to G.S. 62-133.1A(c)(8), service to customers in the service area of the Local Government Utility shall be under a tariff that includes rates equal to the rates of the selling utility until the utility's next general rate case, unless otherwise ordered by the Commission for good cause shown. An application filed pursuant to G.S. 62-133.1A and this Rule shall include a proposed tariff that reflects such rates and a statement as to whether the utility intends to propose in its next general rate case that the service area of the Local Government Utility be integrated into an existing Rate Division of the acquiring utility or be established as a new Rate Division. A determination as to whether the service area of the Local Government Utility should be integrated into an existing Rate Division or established as a new Rate Division shall be preserved for the Commission's consideration in the utility's next general rate case.

(g) Final Order on Application.—Consistent with the direction provided in G.S. 62-133.1A(d), the Commission will endeavor to issue a final order on the application filed pursuant to G.S. 62-133.1A and this Rule within six months of the filing of a completed application. The Commission's final order will resolve all substantive issues and, if the Commission determines that the Application should be approved, the Commission will specifically determine the rate base value of the acquired property for rate-making purposes in a manner consistent with G.S. 62-133.1A and the provisions of this Rule, as follows:

(1) Determination of Rate Base.—

~~(1)~~ .—The rate base value of the acquired system~~, which shall be reflected in the acquiring Public Utility's next general rate case for rate making purposes,~~ shall be the lesser of the purchase price ~~negotiated between the parties to the sale,~~ reflected in the Asset Purchase Agreement, or the "average of the three appraisals required pursuant to G.S. 62-133.1A (b)(1), unless the Commission specifically finds that the average of the appraisals will not result in a reasonable fair value~~" plus the fees~~, in which case the Commission may adjust the fair value pursuant to G.S. 62-133.1A(e) as it deems appropriate and in the public interest;

(2) Certain Costs Eligible to be Included in Rate Base Value.—Consistent with G.S. 62-133.1A(b), the Commission will allow the inclusion of the costs ~~authorized in subsection (2) of this section, below.~~

~~(2) As determined by the Commission, reasonable~~ of the engineering assessment, transaction and closing costs incurred by the utility, and fees paid to Utility Valuation Experts, including ~~for the engineering assessment and reasonable transaction and closing costs incurred~~fees paid by the acquiring ~~Public~~utility to a Utility ~~may be included~~Valuation Expert that represents the Public Staff, in the ~~cost~~rate base value of the acquired system~~.~~ upon a finding that those costs were reasonably and prudently incurred;

(3)~~The~~ Depreciation.—The Commission will require the utility to apply the normal rules of depreciation ~~shall begin to apply~~ against the rate base value

~~upon~~from the date of the purchase of the system ~~by the acquiring Public Utility.~~; and

~~(g) Rate Division Assignment.~~

~~(1) In any Application filed under G.S. 62-133.1A, the acquiring Public Utility shall state whether it plans in the future to propose that the service area of the customers of the Chapter 162A Utility being acquired should be integrated into an existing Rate Division.~~

~~(2) The acquiring Public Utility, in its next general rate case, shall propose whether the service area of the customers acquired from the Chapter 162A Utility should be integrated into an existing Rate Division of the Public Utility or should be established as a new Rate Division. If the recommendation is for integration into an existing Rate Division, the acquiring Public Utility shall recommend how the area is to be integrated, including any necessary tariff revisions, and shall have the burden of proof to demonstrate that such integration is in the public interest. If the recommendation is for establishment of a new Rate Division, the acquiring Public Utility shall include proposed tariffs or tariff revisions as part of its Application.~~

~~(h) Regulatory Application Process for Determination of Fair Value and of Rate Base.—A Public Utility Application for Determination of Fair Value and Rate Base and Approval of~~

~~Transfer, filed under these Rules, shall be signed and verified by the president or designated officer of the acquiring Public Utility and shall contain all of the following:~~

~~(1) explanation of the object and purposes desired and of the public interest served by the acquisition;~~

~~(2) copies of the appraisals or valuations performed by the three Utility Valuation Experts, of the engineering assessment, and of the Asset Purchase Agreement;~~

~~(3) a statement of any deficiencies identified by the engineering assessment, and a five-year plan for prudent and necessary infrastructure improvements;~~

~~(4) the projected rate impact for the customers of the selling Chapter 162A Utility for the next five years;~~

~~(5) a proposed tariff;~~

~~(6) any recommendations for Rate Division assignment of the customers of the Chapter 162A utility being acquired;~~

~~(7) a map of the service area for the system(s) being acquired;~~

~~(8) the total cost of obtaining the valuations, including the estimated valuation fees, engineering fees, and transaction and closing costs incurred by the acquiring Public Utility; and~~

~~(9) any other information required or relevant under G.S. 62-133.1A.(e).~~

~~(i) Final Order. If the Application meets the requirements of G.S. 62 133.1A.(e), the Commission's order approving or denying the Application must be issued within six~~

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~~months of the date of filing of the Application, in accordance with G.S. 62-133.1A.(d). In an order approving an Application, the Commission shall include the following:~~

~~(1) A determination of the fair value and the rate base value, inclusive of costs delineated in subsection (h)(8) of this rule, of the acquired utility property for rate-making purposes;~~

~~(2) The Rate Division under which the acquired service area shall be served; and~~

~~(3) Approval of the necessary tariffs or tariff revisions.~~

~~(j) Discovery.~~

~~(1) All parties to the proceeding shall be permitted to serve (by hand delivery, facsimile or electronic delivery) data requests upon the selling Chapter 162A Utility, the purchasing Public Utility, the Public Staff, any Intervenor, the Licensed Professional Engineer, and/or one or more of the Utility Valuation Expert(s);~~

~~(2) The return date on each data request shall be ten business days. The party served with discovery shall have up to ten business days to file objections to the discovery request on an item-by-item basis; and~~

~~(3) Subject to the agreement of the selling Chapter 162A Utility, the Public Staff shall have authority to make site visits to the utility system.~~

~~(k) Evidentiary Hearing. If deemed appropriate, the Commission may schedule the Application for evidentiary hearing and require the prefiling of testimony.~~

~~(l) Customer Notice. The Commission shall require the selling Chapter 162A Utility to provide to each of its customers, by bill insert or first-class mail, a Commission-approved Customer Notice pursuant to a Commission prescribed schedule.~~

~~(m) Intervention. Any customer of the selling Chapter 162A Utility, or a person having a demonstrated real and direct interest in the sale of the water and/or wastewater system to the purchasing Public Utility, may become a party to the Fair Value Purchase proceeding by filing a petition pursuant to Commission Rule R1-19. The Commission, in each Fair Value Purchase proceeding, shall set the deadline for filing a petition to intervene.~~

~~(n) Public Interest. If the Commission finds that the average of the appraisals will not result in a reasonable fair value, the Commission may adjust the fair value as it deems appropriate and in the public interest. The decision should be supported with appropriate and sufficient findings and conclusions.~~

~~(o) Burden of Proof. The acquiring Public Utility shall have the burden of proof in the Application proceeding. (p)~~ (4) Tariffs.—The Commission will approve the establishment of a new tariff for the provision of wastewater service to customer in the acquired service territory, which shall also determine whether the acquired service territory will be treated as a separate Rate Division.

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(h) Burden of Proof.—The utility shall have the burden of proof regarding all aspects of the proceeding on an application filed pursuant to G.S. 62-133.1A and this Rule, and for demonstrating that the acquisition of the Local Government Utility is in the public interest.

(i) Payment of Fees for Public Staff Utility Valuation Expert. ~~—~~The acquiring ~~Public Utility~~ utility shall pay the fees of the ~~Public Staff~~ Utility Valuation Expert ~~should~~that represents the Public Staff whether the Commission ~~deny the Application~~approves the application, denies the application, or ~~should~~ if the acquiring ~~Public Utility withdraw~~ the ~~Application~~ application.

~~(q) Engineering Assessment Rule. The Water and Wastewater Fair Value Engineering Assessment Form, Sewer Fair Value 1, will be provided to the Licensed Professional Engineer prior to engineering review, and shall serve as the template for the engineer's assessment. Information requested on this guide shall only be included if it is applicable and readily available.~~

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DOCKET NO. W-___________

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
APPLICATION FOR DETERMINATION OF FAIR VALUE OF UTILITY ASSETS
PURSUANT TO N.C.G.S. § 62-133.1A

INSTRUCTIONS

If additional space is needed, supplementary sheets may be attached. If any section does not apply, write "not applicable".

PURCHASER – APPLICANT PUBLIC UTILITY

1. Trade name used for utility business: ______________________________

2. Name of owner (if different from trade name): ______________________________

3. Business mailing address: ______________________________

City and state: ______________________ Zip Code: __________

4. Business street address (if different from mailing address): ___________

____

5. Business telephone number: ______________________________

6. Business email address: ______________________________

7. If corporation, list the following:

President: __________________ Vice President: ______________________

Secretary: __________________ Treasurer: ______________________

Three (3) largest stockholders and percent of voting shares held by each: ___________

____

8. If partnership, list the owners and percent of ownership held by each: ___________

____

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SELLER – LOCAL GOVERNMENT UTILITY

1. Trade name used for utility business: ______________________
2. Name of owner (if different from trade name): ______________________
3. Mailing address: ______________________
4. Business telephone number: ______________________
5. Business email address: ______________________
6. Form of Organization (municipality/county/authority or district established under Chapter 162A):

____

REQUIRED EXHIBITS

The following information is required to be included in this Application, and should be attached hereto as exhibits numbered to correspond to this list:

1. Copies of the valuations performed by the three separate appraisers, as provided in N.C.G.S. § 62-133.1A(b)(1).
2. Any deficiencies identified by the engineering assessment conducted pursuant to N.C.G.S. § 62-133.1A(b)(2) and a five-year plan for prudent and necessary infrastructure improvements by the acquiring entity.
3. The projected rate impact for the selling entity's customers for the next five years.
4. The averaging of the appraisers' valuations, which shall constitute fair value for purposes of N.C.G.S. § 62-133.1A.
5. The assessment of tangible assets performed by a licensed professional engineer, as provided in N.C.G.S. § 62-133.1A(b)(2). Utilize Commission Form FV1(a) as a template for the engineer's assessment, indicating if any of the requested information is not applicable or not readily available. Additional information that is relevant to the application that is not listed on the Form FV1(a) should be included as an attachment or addendum to the engineer's assessment.
6. The contract of sale or Asset Purchase Agreement, including exhibits showing that the Seller has ownership of all property necessary to operate the system being acquired. Any changes to the contract of sale or Asset Purchase Agreement should be filed immediately with the Commission.

7. Enclose a copy of contracts or agreements, including all attachments, exhibits, and appendices, between the seller and any other party (municipalities, towns, districts, customers, etc.) regarding the proposed utility services, including contracts regarding easements and rights of way, etc. (If none, write "none"__________.)
8. The estimated valuation fees and transaction and closing costs incurred by the acquiring public utility.
9. A map of the service area for the system(s) being acquired.
10. Current number of water and sewer customers by type of customer (residential, commercial, etc.).
11. A copy of the seller's schedule of rates that are currently being charged to customers for the provision of water and sewer service.
12. A tariff, including rates equal to the rates of the selling utility. The selling utility's rates shall be the rates charged to the customers of the acquiring public utility until

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the acquiring public utility's next general rate case, unless otherwise ordered by the Commission for good cause shown.

ADDITIONAL REQUIREMENTS FOR FILING OF APPLICATION

In addition to the other information required to be included in this application, the Purchaser-Applicant Public Utility must include the testimony of the public utility's president or another person employed by the public utility who is personally familiar with the contents of this application which provides a narrative explanation of the object and purposes desired by the application and how the public interest is served by the proposed acquisition. The person providing testimony in support of this application shall complete and sign the attached verification form before a Notary Public, verifying that the contents of this application are true and accurate.

VERIFICATION

STATE OF __________________ COUNTY OF __________________

______________________, personally appeared before me this day and, being first duly sworn, says that the facts stated in the foregoing application and any exhibits, documents, and statements thereto attached are true as he or she believes.

WITNESS my hand and notarial seal, this ____________ day of _________________, 20___.

My Commission Expires:

____

Signature of Notary Public

____

Name of Notary Public – Typed or Printed

The name of the person who completes and signs this verification must be typed or printed by the notary in the space provided in the verification. The notary's name must be typed or printed below the notary's seal. This original verification must be affixed to the original application that is submitted to the Commission.

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FILING INSTRUCTIONS

Electronic filing is available at www.ncuc.net for application submittal or mail one (1) original application with required exhibits and original notarized verification form, plus three (3) additional collated copies to:

USPS Address:	OR	Overnight Delivery at Street Address:
Chief Clerk's Office North Carolina Utilities Commission 4325 Mail Service Center Raleigh, North Carolina 27699-4300		Chief Clerk's Office North Carolina Utilities Commission 430 North Salisbury Street Raleigh, North Carolina 27603-5918

Provide a self-addressed stamped envelope, plus an additional copy of the application, if a file-stamped copy is requested by the Applicant.

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ESTABLISHED 12/2020 PAGE 1 of 9

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

FAIR VALUE ENGINEERING ASSESSMENT FORM

INSTRUCTIONS

If additional space is needed, supplementary sheets may be attached. If any section does not apply, write "not applicable". Additional information that is relevant to the application that is not listed on this form should be included as an attachment or addendum

Note: This form is only to be used in conjunction with Form FV1, Application for Determination of Fair Value of Utility Assets Pursuant to G.S. 62-133.1A.

SELLER-LOCAL GOVERNMENT UTILITY

1. Trade name used for utility business: ____________________

2. Name of owner (if different from trade name): ____________________

3. Description of the water system ____________________

4. County where located ____________________

5. Description of the sewer system ____________________

6. County where located ____________________

7. Number of current customers: water __________ sewer: __________

ENGINEER INFORMATION

1. Name of Engineer Providing Utility Assessment : ____________________
2. Engineer Background Information:
License No. and Issuing Authority: ____________________
Education: ____________________
Has Engineer been subject to Discipline by any State Licensing Authority (if yes, provide date and cause of discipline): ____________________

____

3. Engineer's experience with engineering design, planning, construction, renovations, replacements and operations of water and wastewater utility systems: __________

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ASSESSMENT OF TANGIBLE ASSETS OF SYSTEM TO BE ACQUIRED

Water Utility System Information

Distribution System Information

1. Water Mains (Provide the following information for each section of water mains):

   a. Year installed: ____________________

   b. Pipe diameter: ____________________

   c. Length of main: ____________________

   d. Type of pipe material (i.e., asbestos cement, galvanized, PVC Class 160, PVC SDR 21, C-900, ductile iron, other):

   ____

   e. Copy of Department of Environmental Quality (DEQ) approval for each section, if available: ____________________

   f. Describe the condition of the water distribution system valves:

   ____

   g. Describe condition of service lines, including materials:

   ____

   h. Describe the condition of the fire hydrants in each section:

   ____

2. Water Meters

   a. Type of meters (i.e., manual read, AMR, AMI, other):

   ____

   b. Average age of residential water meters: ____________________

3. Customer growth – number of customers added or lost during last 3 years in each of the following categories:

a. Residential: ______________________________

b. Commercial: ______________________________

c. Industrial: ______________________________

d. Governmental, including schools: ______________________________

4. Water Storage:

a. Describe each water storage facility by type and capacity (i.e. hydropneumatic, ground storage, elevated storage, other):

____

____

b. Provide the year each storage facility placed in service:

____

____

c. Provide the most recent year each storage facility was recoated on interior and exterior:

____

____

____

5. Water Production – Water Wells

a. Provide number of water supply wells in service:

____

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b. For each water supply well in service provide the year first placed in service:

____

c. Provide for each water supply well the original 24 hour well drawdown test, if available.

d. Provide the original DEQ approval for each supply well.

____

____

e. Provide the three most recent inorganic analyses for each well.

____

____

f. Provide the average gallons per minute pumped from each well for the most recent 24 months:

____

____

g. Environmental Compliance:

(i) Does any well exceed the EPA or State of North Carolina maximum contaminant level for a primary drinking water contaminant?

____

____

(ii) If yes, please provide the three most recent analyses for that primary contaminant from that well.

____

____

h. Provide a description of the installed treatment for each primary contamination MCL:

____

i. Does the water system exceed the EPA action levels for lead and/or copper?

____

j. Provide a summary of the condition of each well house, including controls and valve banks and needed renovations.______________________

k. Describe the water treatment of each well, including filters and the need for replacements or renovations as necessary.______________________

6. Surface Water Treatment Plant

a. Year of original construction___________________

b. Capacity of "original plant"____________________

c. Describe all treatment stages, including advanced treatment based on ultrafiltration technology, if applicable. ________________________

d. Type of structure (i. e., steel, concrete, other)__________________

e. History of Expansion

(i) Year of each expansion, if any__________________________

(ii) Additional capacity of each expansion____________________

(iii) Treatment stages of each expansion_________________ (iv)Type of structure of each expansion (i.e., steel, concrete, other)____________

f. Provide copies of DEQ construction permits for the original construction and all expansions, if any.______________________

g. Provide copy of the most recent DEQ permit.

h. Provide copies of the two most recent DEQ inspection reports.

i. Provide copies of all DEQ issued Notices of Violation (NOV) for the last five years, if any.____________________

j. Provide copies of all the selling government entity's responses to each DEQ issued NOV the last five years, if any.____________________

k. Provide the monthly average gallons per day produced by the surface treatment plant for each of the last 36 months____________________

l. Provide the non-revenue water percentage for each of the last three years (water produced at the surface water treatment plant less water billed to customers, divided the water produced)__________________________

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m. Describe in detail renovations and remediations, if any, performed by the selling government entity, the most recent ten years____________________

7. Water and General Upgrading and Renovations – Costs

Provide the estimated cost of each water system upgrades/renovations necessary during the first five years____________________________________

8. Violations – Water System

a. Provide all water system NOVs received from DEQ the last five years.

b. Provide all the selling government entity's written responses to the NOVs received the last five years.

Wastewater System

Collection System

1. For each section of gravity collection mains provide:

a. Year installed_________________________________

b. Pipe diameter_________________________________

c. Length of main_________________________________

d. Type material – i.e., clay pipe, steel pipe, concrete pipe, HDPE pipe, PVC Class 160, PVC SDR 21, C-900, ductile iron, lined ductile iron, other

____

e. Copy of DEQ construction permit for each section, if available.

f. Number of manholes_________________________________

g. Condition of manholes_________________________________

h. Service line materials_________________________________

i. Last time section camera evaluated_________________________________

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2. For each section of collection force mains, provide:

a. Year installed_________________________________

b. Pipe diameter_________________________________

c. Length of main_________________________________

d. Type material – i.e. PVC SDR 21, C-900, ductile iron, lined ductile iron, other

____

e. Copy of DEQ construction permit for each section, if available.

3. Wastewater Lift Stations – For each provide:

a. Year installed_________________________________

b. Capacity of installed pumps_________________________________

c. Permitted capacity of lift station_________________________________

d. Control system_________________________________

e. Alarm System_________________________________

f. Description of recent renovations, if any.____________________________

g. Material of wet well____

h. Provide summary of the conditions of each lift station

____

4. Wastewater Treatment Plant, provide the following:

a. Year of original construction____________________________________

b. Capacity of "original plant"____________________________________

c. Type Treatment____

d. Type structure i.e., steel, concrete, other_____________________________

e. (i) Year of each expansion, if any (ii) Additional capacity of each expansion (iii) Type treatment of each expansion (iv) Type of structure each expansion i.e.

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steel, concrete, other____

f. Provide copies of DEQ construction permits for the original construction and all expansions, if any.

g. Provide copy of most recent NPDES Permit, if applicable.

h. If effluent land application, provide copy of most recent land application permit.

i. If land application, provide the permitted capacity of the installed irrigation system or infiltration system.

j. Does the seller own or have perpetual easements or leases for all of the effluent irrigation/infiltration areas.

____

k. If an easement or lease, provide a copy of the recorded document(s).

l. Provide copies of the monthly DMRs (NPDES Permit) or NDMR (land application) for the most recent 36 months.

m. Provide copy of the most recent wastewater treatment plant permit, including all required monitoring parameters

n. Provide copies of the two most recent DEQ inspection reports for the wastewater treatment plant.

5. Wastewater, general information

a. Provide copies of all DEQ issued NOVs for the last five years, if any.

b. Provide copies of all the selling government entity's responses to each of the DEQ issued NOV the last five years, if any.

c. Provide the average total gallons per day sold to metered water customers by the water utility provider for each of the last three years.

d. Provide the infiltration percentage for each of the last three years (influent wastewater to wastewater treatment plant less metered water sold, divided by the metered water sold)________________________

e. Describe in detail collection system infiltration remediation if any, performed by the selling government entity the most recent ten years____________________

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f. Provide the monthly number of wastewater customers the most recent 36 months:

(i) Residential________________________

(ii) Commercial________________________

(iii) Industrial________________________

(iv) Governmental, including schools____________________

DOCKET NO. A-41, SUB 19

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Bald Head Island Transportation,	)	ORDER APPROVING
Inc., to Implement Temporary Ferry Schedule	)	MODIFIED FERRY SCHEDULE
and Policies and for Expedited Approval of	)	AND TEMPORARY PROCEDURES
Application	)	IN RESPONSE TO THE
	)	COVID-19 PANDEMIC

BY THE COMMISSION: On March 19, 2020, in response to the current COVID-19 pandemic the Commission issued an Order in Docket M-100, Sub 158 that directed:

> If, due to the current State of Emergency, a public utility finds it necessary to further deviate from its approved tariffs or Commission regulations, such as policies that would impose a service continuity hardship or create an unnecessary risk of human contact, the public utility should file a request with the Commission for prior approval on an expedited basis.

On March 25, 2020, Bald Head Island Transportation, Inc. (BHIT or Applicant), filed with the Commission an application seeking expedited approval of a Modified Ferry Schedule and temporary Emergency Procedures in anticipation of any applicable shelter-in-place order due to the COVID-19 pandemic. BHIT also asks that any modified schedule and policies be in place for the duration of such order. Specifically, BHIT states that its

> management wants to be prepared for any applicable "stay-at-home" order or the equivalent legal requirement by the State of North Carolina, the City of Southport, the Village of Bald Head Island, or Brunswick County (any of which is hereinafter referred to as an "applicable Stay-at-Home Order") and has undertaken substantial contingency planning to determine the appropriate course of action in response to any such order.

BHIT states that it has consulted with "local and state government leadership and stakeholder leadership, health officials, the United States Coast Guard, the NCUC Public Staff, and BHIT's ferry captains and crews." Based upon those communications, and (1) in the exercise of its best judgment as to how best to prudently protect the health of passengers, captains, and crew; (2) in order to be able to comply with any applicable Stay-at-Home order; and (3) to ensure the continued operations of the ferry system consistent with United States Coast Guard, it proposes the following modified ferry schedule and temporary policies in response to an "applicable Stay-at-Home Order":

> (1) That regular ferry service to and from Bald Head Island be curtailed, and consist of a "Single Shift" ferry service departing on the hour, beginning at 8:00 a.m., from Deep Point Terminal on the mainland, and departing on the half hour beginning at 8:30 a.m., from Bald Head Island Terminal, returning

to Deep Point. Final mainland departure from Deep Point Terminal will be 5:00 p.m., and final Island departure from Bald Head Island Terminal will be 5:30 p.m.;

(2) That contactor ferry service to and from Bald Head Island continue to operate on its normal schedule;

(3) That all ferry vessels departing the mainland from Deep Point Terminal be limited to 25 passengers plus crew. All ferry vessels departing the island from Bald Head Island Terminal be limited to 35 passengers plus crew;

(4) That in-bound passenger tram service (i.e., trams operating from Bald Head Island Terminal to Island destinations) be suspended. Out-bound passenger tram service (i.e. trams operating from Island locations to Bald Head Island Terminal) is to remain operational subject to passengers securing a tram reservation;

(5) That contractor shuttle service to and from the Bald Head Island Terminal continue to operate on its normal schedule; and

(6) That the lounge at Deep Point Terminal be closed.

BHIT also attaches as Appendix B to its application its proposed Modified Ferry Schedule to be posted at the Deep Point and Bald Head Island ferry terminals and on the Bald Head Island website.

The Public Staff has reviewed the proposed Emergency Policies and Modified Ferry Schedule and has no objection to their approval for the duration of any applicable Stay-At-Home Order.

Based on the foregoing and the recommendation of the Public Staff, the Commission finds good cause to approve the proposed revisions to BHIT's ferry schedules and proposed emergency policies contingent upon the implementation, and for the duration, of any applicable Stay-At-Home Order.

IT IS, THEREFORE, ORDERED as follows:

1. That the Modified Ferry Schedule and Emergency Procedures proposed by BHIT, and as set out above, be effective at the effective time and date of any applicable Stay-at-Home Order, last for the duration of any such Order, and expire at the expiration or termination of any such order;

2. That BHIT shall file with the Commission in the above-captioned docket notice when, and if, the Modified Ferry Schedule and Emergency Procedures become effective due to any applicable Stay-At-Home Order issuing, and subsequent notice, if necessary, when the

Modified Ferry Schedule and Emergency Procedures have expired due to the expiration or termination of any such order; and

3. That BHIT shall provide notice of these changes by posting a copy this Order and the Modified Ferry Schedule and Emergency Procedures at the Deep Point and Bald Head Island ferry terminals and on the Bald Head Island website.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of March, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

DOCKET NO. A-41, SUB 19

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Bald Head Island	)	ORDER APPROVING AMENDED
Transportation, Inc., to Implement	)	TEMPORARY FERRY SCHEDULE
Temporary Ferry Schedule and Policies and	)	AND POLICES IN RESPONSE TO
for Expedited Approval of Application	)	THE COVID-19 PANDEMIC

BY THE COMMISSION: On April 23, 2020, Bald Head Island Transportation, Inc. (BHIT or Applicant), filed with the Commission a motion seeking expedited approval to amend the temporary Modified Ferry Schedule and Emergency Operating Procedures previously approved by the Commission in the above-captioned docket by order dated March 26, 2020, and that have been effective since March 31, 2020. BHIT also asks that any modified schedule and policies be in place for the duration of any Stay-At-Home Order. Specifically, BHIT states:

> The Modified Ferry Schedule and Emergency Operating Procedures were prepared by BHIT based upon contingency planning to determine an appropriate course of action in anticipation of, but prior to, the issuance of any applicable Stay-at-Home Order. BHIT pro-actively wanted to have the schedule and procedures approved prior to the issuance of an applicable Stay-at-Home Order so it could act quickly if and when such a "Stay-at-Home Order" was issued, and to be in compliance of such an order, rather than re-actively after such an order was issued.

In support of its motion, BHIT states that (1) it has three full weeks of experience to evaluate how the schedule and procedures are functioning, its effect on personal and ferry operations, and its ability to accommodate the transportation needs of ferry customers while still protecting public health and safety; and (2) warmer weather has resulted in more passengers willfully observing social distancing requirements by staying on the exterior areas of vessels and an increase of construction activity on the island, deemed an "essential service" under all applicable Stay-at-Home Orders. Based upon this experience, BHIT proposes the following amendments to the current Modified Ferry Schedule and Emergency Operating Procedures:

A. For the Contractor Ferry:

i. Increasing in-bound (to Bald Head Island from Deep Point Terminal) maximum total passenger limit to Bald Head Island from 25 to 35. (The out-bound maximum total passenger limit from Bald Head Island to Deep Point Terminal would remain at 35.)

ii. Adding a 5:30 p.m. departure from Deep Point and a 6:00 p.m. departure from Bald Head Island.

B. For the Regular Passenger Ferry:

i. Increasing in-bound (to Bald Head Island from Deep Point Terminal) maximum total passenger limit to Bald Head Island from 25 to 35. (The out-bound maximum total passenger limit from Bald Head Island to Deep Point Terminal remains at 35.)

ii. Adding a 7:00 a.m. departure from Deep Point and a 7:30 a.m. departure from Bald Head Island in the morning, and adding a 6:00 p.m. departure from Deep Point and a 6:30 p.m. departure from Bald Head Island in the evening.

BHIT states that these changes will enable it to better meet the transportation needs of its customers by reducing the potential of "bumped" passengers who cannot board a vessel and must then wait until the next departure, and still satisfy the social distancing spacing necessary to protect public health and safety.

Lastly, BHIT states that the Public Staff has reviewed the proposed amendments and has no objection to their implementation.

Based on the foregoing and the recommendation of the Public Staff, the Commission finds good cause to approve the proposed revisions to BHIT's temporary Modified Ferry Schedule and Emergency Operating Procedures for the remaining duration of any applicable Stay-At-Home Order.

IT IS, THEREFORE, ORDERED as follows:

1. That the amendments to the Modified Ferry Schedule and Emergency Operating Procedures proposed by BHIT, and as set out above, be effective within 14 calendar days after the issuance of this Order, last for the duration of any applicable Stay-At-Home Order, and expire at the expiration or termination of any such Stay-At-Home Order;

2. That BHIT shall file with the Commission in the above-captioned docket notice when, and if, the amendments to the Modified Ferry Schedule and Emergency Operating Procedures become effective, and subsequent notice when the Modified Ferry Schedule and

Emergency Operating Procedures have expired due to the expiration or termination of any applicable Stay-At-Home Order; and

3. That BHIT shall provide notice of these changes by posting a copy of this Order and the amended Modified Ferry Schedule and Emergency Operating Procedures at the Deep Point and Bald Head Island ferry terminals and on the Bald Head Island website, send mass e-mails to island property owners, and inform passengers who call to make ferry reservations.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of April, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Joann R. Snyder, Deputy Clerk

DOCKET NO. A-41, SUB 19

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Bald Head Island	)	ORDER APPROVING AMENDED
Transportation, Inc., to Implement	)	TEMPORARY FERRY SCHEDULE
Temporary Ferry Schedule and Policies and	)	AND POLICIES IN RESPONSE TO
for Expedited Approval of Application	)	THE COVID-19 PANDEMIC

BY THE COMMISSION: On May 6, 2020, Bald Head Island Transportation, Inc. (BHIT or Applicant), filed with the Commission a second motion seeking expedited approval to amend the temporary Modified Ferry Schedule and Emergency Operating Procedures previously approved by the Commission by order dated April 24, 2020, and that have been effective since April 27, 2020.

In support of its motion, BHIT states that (1) on May 28, 2020, Executive Order No. 138 (EO 138) was issued by Governor Roy Cooper implementing Phase 1 which eases restrictions on travel, business operations, and mass gatherings; (2) there is need to accommodate increased ridership demands and transportation needs of its customers as restrictions on travel are eased by this and future Executive Orders, while still protecting public health and safety; (3) warmer weather has resulted in more passengers staying on the exterior areas of the vessels, as well as an increase in "essential construction activity" on the island; (4) there is increased demand from homeowners who may have multiple residences and who are likely to travel to, and spend more time on Bald Head Island as the weather warms, and as such BHIT anticipates that this increased ridership will accelerate in the coming weeks; and (5) BHIT has been able to successfully and smoothly implement the first amendments to the Modified Ferry Schedule and Emergency Operating Procedures approved by the Commission in its April 24, 2020 Order, and believes that it can do the same for this set of amendments, while still protecting public health and safety of its passengers.

Based upon this experience, BHIT proposes the following amendments to the current Modified Ferry Schedule and Emergency Operating Procedures:

A. For Both the Contractor Ferry and Regular Passenger Ferry:

i. Increasing the maximum number of passengers per trip to 75. This is half of the 150-passenger capacity of the vessels, which is consistent with EO 138, Sec. 3.B.1.

ii. Requiring all passengers to wear a "hands free" facial mask/covering, as defined by EO 138, Sec. 1.3, at all times on passenger vessels and trams, as recommended by EO 138, Sec. 2.A.2.

B. For the Regular Passenger Ferry:

i. Adding a 7:00 p.m. departure from Deep Point and a 7:30 p.m. departure from Bald Head Island in the evening to accommodate passengers who may be "bumped" and unable to ride earlier departures and those who are arriving later in the day to stay on the island.

ii. Re-commencing in-bound tram service from the Bald Head Island Ferry Terminal to island destinations that were part of the pre-COVID-19 service but were previously suspended by the Modified Ferry Schedule and Emergency Operating Procedures approved by the Commission.

BHIT states that these changes are needed and constitute an appropriate balance between meeting customer transportation demand and protecting public health and safety.

Lastly, the Public Staff has reviewed BHIT's second motion and the proposed amendments and does not oppose their implementation.

Based on the foregoing, and the position of the Public Staff, the Commission finds good cause to approve the proposed revisions to BHIT's temporary Modified Ferry Schedule and Emergency Operating Procedures.

IT IS, THEREFORE, ORDERED as follows:

1. That the Modified Ferry Schedule and Emergency Operating Procedures proposed by BHIT, and as set out above, be effective within 14 calendar days after the issuance of this Order, last for the duration of any applicable Stay-At-Home Order, and expire at the expiration or termination of any such Stay-At-Home Order;

2. That BHIT shall file with the Commission in the above-captioned docket notice when, and if, these amendments to the Modified Ferry Schedule and Emergency Operating Procedures become effective, and subsequent notice when the Modified Ferry Schedule and Emergency Operating Procedures have expired due to the expiration or termination of any applicable Stay-At-Home Order; and

3. That BHIT shall provide notice of these changes by posting a copy of this Order and the second amended Modified Ferry Schedule and Emergency Operating Procedures at the Deep Point and Bald Head Island ferry terminals and on the Bald Head Island website, send mass e-mails to island property owners, and inform passengers who call to make ferry reservations.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of May, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. A-41, SUB 19

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Bald Head Island	)	ORDER REVERTING TO REGULAR
Transportation, Inc., to Implement	)	FERRY SCHEDULES BUT
Temporary Ferry Schedule and Policies and	)	MAINTAINING EMERGENCY
for Expedited Approval of Application	)	OPERATING PROCEDURES

BY THE COMMISSION: On May 22, 2020, Bald Head Island Transportation, Inc. (BHIT or Applicant), filed with the Commission a Motion seeking expedited approval to rescind the temporary modified ferry schedules (Modified Ferry Schedules) and to revert to the regular summer schedules for ferry operations as previously approved by the Commission in Docket No. A-41, Sub 18 (Regular Ferry Schedules), but to maintain emergency operating procedures (Emergency Operating Procedures) limiting the maximum passengers per trip and requiring face covering, as previously approved in the above-captioned docket by Order dated May 8, 2020, and that have been effective for the regular passenger ferry since Saturday, May 9, and for the contractor ferry since Monday, May 11.

In support of its motion, BHIT states that: (1) Governor Roy Cooper issued Executive Order No. 141 (EO141), easing restrictions on travel, business operations, and mass gatherings during Phase 2; (2) EO141 maintains certain provisions of the previously issued Executive Order 138 but does allow the opening of beaches and designated businesses with restrictions; (3) EO141 takes effect at 5:00 pm on Friday, May 22, 2020; and (4) BHIT has been able to successfully and smoothly implement the Emergency Operating Procedures approved by the Commission in its May 8, 2020 Order. In light of EO141, BHIT moves to rescind the Modified

Ferry Schedule and revert to the previously approved Regular Ferry Schedules, labelled and attached as Appendix B3 for Contractor Ferry Services, and Appendix C3 for Passenger Ferry and Tram Services.

BHIT also proposes maintaining the Emergency Operating Procedures for both the Contractor Ferry and Passenger Ferry and Tram Operations as follows:

A. Maintaining the maximum number of passengers per trip at 75. This number is fifty percent (50%) of the 150-passenger capacity of the vessels, consistent with EO141, Sec. 6.B.1; and

B. Requiring all passengers to wear a "hands free" facial mask/covering that is consistent with the definition of "Face Covering" in EO141, Sec. 1.4, at all times on passenger vessels and on all trams, consistent with EO141, Sec. 3.B.2 ("inside all public settings . . . and outdoors when you cannot maintain at least six (6) feet distancing").

BHIT believes that these measures are needed and constitute an appropriate balance between meeting customer transportation demand and protecting public health and safety.

BHIT further asks that these measures be maintained until the earliest of (1) a further amendment, modification, or rescission by order of the Commission or (2) the expiration of the last applicable Executive Order by the State of North Carolina, Brunswick County, City of Southport, or Village of Bald Head Island pertaining to restrictions on travel, business operations, or mass gatherings arising from the COVID-19 pandemic.

According to BHIT the Public Staff has reviewed BHIT's motion and proposed changes and does not oppose their implementation.

Based on the foregoing, and the position of the Public Staff, the Commission finds good cause to rescind the previously Modified Ferry Schedule and revert to the Regular Ferry Schedules as previously approved by the Commission in Docket No. A-41, Sub 18. The Commission also finds good cause to maintain the Emergency Operating Procedures limiting maximum passengers per trip and requiring face covering, as previously set out by the May 8, 2020 Order in the above-captioned docket, until further order by the Commission.

IT IS, THEREFORE, ORDERED as follows:

1. That the previously approved Modified Ferry Schedules be rescinded and revert to the Regular Ferry Schedules as previously approved by the Commission in Docket No. A-41, Sub 18, as proposed by BHIT and attached to its motion as Appendices B3 and C3, and be effective within 48 hours after the issuance of this Order;

2. That the Emergency Operating Procedures approved by the Commission's May 8, 2020 Order, and as set out above, be maintained until further order by the Commission;

3. That BHIT shall file with the Commission in the above-captioned docket notice when, and if, the Modified Ferry Schedule is rescinded and the Regular Ferry Schedules become effective; and

4. That BHIT shall provide notice of these changes by posting a copy of this Order and the Regular Ferry Schedules and Emergency Operating Procedures at the Deep Point and Bald Head Island ferry terminals and on the Bald Head Island website, send mass e-mails to island property owners, and inform passengers who call to make ferry reservations.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of May, 2020.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

DOCKET NO. A-41, SUB 19

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Bald Head Island	)	ORDER ALLOWING SECOND
Transportation, Inc., to Implement	)	MOTION TO MODIFY FERRY
Temporary Ferry Schedule and Policies and	)	VESSEL CAPACITY LIMIT TO 100
for Expedited Approval of Application	)	

BY THE COMMISSION: On September 15, 2020, Bald Head Island Transportation, Inc. (BHIT or Applicant), filed with the Commission a Motion seeking expedited approval to modify the ferry vessel capacity limit to allow a maximum of 100 passengers per voyage instead of the maximum of 75 passengers as previously approved by the Commission by Order dated May 8, 2020 in the above-captioned docket but also seeking to maintain emergency operating procedures (Emergency Operating Procedures) as previously approved, and that have been effective for the regular passenger ferry since Saturday, May 9, and for the contractor ferry since Monday, May 11.

On September 4, 2020, Governor Roy Cooper issued Executive Order No. 163 (EO 163). EO 163 provided that slowing and controlling community spread of COVID-19 remains critical to ensuring that the state's healthcare facilities remain able to accommodate those who require medical assistance. EO 163 also continued to urge all people in North Carolina to follow social distancing recommendations, including that everyone wear a cloth face covering, wait six feet apart and avoid close contact, and wash hands often or use hand sanitizer, and also required safety measures in certain business settings, limited mass gatherings, and closed certain types of businesses and operations. EO 163 recognized in part that

> there has been stabilization in several of North Carolina's key metrics, as emergency department visits for COVID-19 illnesses continue to decline, daily case counts are stable, the percent of COVID-10 tests that are positive are stable, and hospitalization continue to decline . . . .

while also recognizing "that stabilization has been fragile, necessitating that the state remain vigilant to prevent a surge in cases and exercise caution in loosening restrictions in high-risk settings . . . ."

EO 163 also recognized several reasons supporting a "Need for a Phased, 'Dimmer Switch' Approach to Loosening Restrictions." As a result, among other things, EO 163 loosened some restrictions and increased the number of persons allowed to gather under certain circumstances. For example, EO 163 increased the number of persons permitted to convene in mass gatherings from the previously imposed limitation of 10 persons indoors and 25 persons outdoors to 25 persons indoors and 50 persons outdoors at the same time. But EO 163 also maintained numerous restrictions previously put in place, including a cap on the maximum number of guests allowed in various locations by way of the lesser produced by three different metrics, including in some instances 50% of stated capacity.

On September 23, 2020, the Commission issued an Order Denying Motion to Modify Ferry Capacity Limit, based in part upon EO 163 and the reasons set forth therein, as well as the insufficient showing of need set forth in BHIT's motion. The Order also emphasized that the requirements set by the Governor's Executive Order No. 141, and as amended by Executive Orders Nos. 147 and 163, remain in place.

On September 30, 2020, Governor Roy Cooper issued Executive Order No. 169 (EO 169) or "Phase 3". EO 169 maintained many of the restrictions previously put in place, and again provided that slowing and controlling community spread of COVID-19 remains critical. EO 169 also recognized in part that "there have been recent modest declines, compared to July levels, in the percent of emergency department visits [and hospitalizations] that [are COVID-19-associated]" and that these various metrics "have shown stabilization, but remain elevated." EO 169 provided several reasons supporting North Carolina's continued "Need for a Phased, 'Dimmer Switch' Approach to Loosening Restrictions." And, as a result of the trends, it lifted previous restrictions on several entertainment venues, for example, amusement parks, bars, arenas, movie theaters, et al., and in some instances allowed for up to 100 persons to gather in certain indoor and outdoor areas.

On October 5, 2020, BHIT filed with the Commission a Second Motion to Modify Ferry Vessel Capacity Limit to 100 and Otherwise Maintain Operating Policies in Response to COVID-19. In support, BHIT stated that:

> (1) pursuant to the May 8 Order, BHIT has been limiting the number of passengers per ferry voyage to a maximum of 75 passengers, and at the determination of the captain, even less throughout inclement weather;

(2) there are no locally imposed restrictions on short-term rentals or on maintenance and construction activities on the island;

(3) the number of persons on Bald Head Island will be much greater than any fall season in the history of the island. BHIT bases this prediction on several factors including that homeowners, visitors and their children work and attend school remotely; ridership for September 2020 was 24% more than ridership in September 2019; and realtors on the island report that rental occupancy for Columbus Day weekend is at or close to 100%;

(4) increasing the amount of passengers to 100 will reduce the amount of passengers that are bumped from their original scheduled trip to the next scheduled trip. BHIT estimates that wait times for "bumped passengers" can range from one to two hours during the weekdays and up to three of four hours on the weekends;

(5) BHIT has been able to successfully and smoothly implement the Emergency Operating Procedures approved by the Commission in its May 8, 2020 Order – including the requirement of face coverings by all passengers, spatial distancing, and readily available hand sanitizing stations – and will continue to follow them. According to BHIT, as of the date of filing, no BHIT employee has contracted COVID-19 and there have been no cases of infection traced to contact on the ferry; and

(6) Governor Roy Cooper issued EO 169 which increased the number of persons allowed to gather under certain circumstances. Specifically, citing Executive Order 169, section 3.8, BHIT stated that EO 169 allows capacity at 100 persons in a number of venues, including movie theaters, meeting spaces, bingo parlors, et al., and argued that if these venues are allowed to accommodate up to 100 persons (plus workers and support staff), then an essential transportation service should also be allowed to accommodate up to 100 passengers per vessel.

BHIT believes that its request to increase the vessel capacity from 75 to 100 will substantially reduce the number of bumped passengers this fall and constitute an appropriate balance between meeting customer transportation demand and protecting public health and safety consistent with EO 169. BHIT further asks that this maximum passenger capacity limit be maintained until the earliest of (1) a further amendment, modification, or rescission by order of the Commission or (2) the expiration of the last applicable Executive Order by the State of North Carolina, Brunswick County, City of Southport, or Village of Bald Head Island pertaining to restrictions on travel, business operations, or mass gatherings arising from the COVID-19 pandemic.

BHIT also noted the Commission's September 23, 2020 Order denying a requested increase to 100 passengers, and further noted that its final sentence "encourage[d] BHIT to continually assess its reasons for requesting an increase in vessel capacity and to seek appropriate action as circumstances change." In response, BHIT stated that it has assessed the demand for its services and the available resources to meet that demand continually – each and every day – and believed that circumstances have changed with the announced changes in Phase 3, and EO 169's allowing gatherings of 100 persons in many venues. BHIT emphasized that it has investigated alternative steps to alleviate the wait times and congestion, and options to its ticket and boarding procedures. BHIT has, however, concluded that they either are not, in fact, feasible or that the very real costs of each – in terms of inefficiency, opportunities for gaming the system, and/or potentially inequitable and discriminatory treatment of passengers – outweigh their hypothetical benefits. BHIT also welcomed the opportunity to virtually make a presentation to the Commission of the same. BHIT also emphasized its concern for public health and safety and stated that it would not request a change in policy it feels would place health and safety at risk.

According to BHIT the Public Staff has reviewed BHIT's motion and does not oppose its implementation.

On October 5 and 6, 2020, the Commission received numerous consumer statements of position, either opposing or supporting BHIT's motion, including one from the Mayor of Bald Head Island.

Based on the foregoing, and the position of the Public Staff, the Commission finds good cause to modify the Emergency Operating Procedures limiting maximum passengers per trip, as previously set out by the May 8, 2020 Order and as continued by Orders dated May 22, 2020, June 26, 2020, and September 23, 2020, to allow for a maximum of 100 passengers (plus crew) per ferry voyage. The Commission also finds good cause to maintain these modified Emergency Operating Procedures until further order by the Commission. The Commission recognizes the guidance set out in EO 169 emphasizing the need for a phased approach to loosening restrictions. The Commission continues to emphasize that the requirements set by the Governor's Executive Order No. 141, and as amended by Executive Orders Nos. 147, 163, and 169, remain in place. Accordingly, BHIT must maintain all Emergency Operating Procedures and necessary controls to allow for appropriate social distancing, dutifully and consistently within the spirit and intent of these executive orders, both while passengers wait at terminals and also while they are in transit aboard ferries.

IT IS, THEREFORE, ORDERED as follows:

1. That the Commission's Emergency Operating Procedures be modified to allow for a maximum vessel capacity limit of 100 passengers per voyage, while maintaining the additional Emergency Operating Procedures as previously approved in the Commission's May 8, 2020 Order, and be effective within 36 hours after the issuance of this Order;

2. That these modified Emergency Operating Procedures be maintained until further order by the Commission;

3. That upon any change of circumstances brought to the attention of BHIT regarding whether any BHIT employee has contracted COVID-19 or any case of infection can be traced to contact on the ferry, BHIT shall report the same to the Commission as soon as practicable;

4. That BHIT shall file with the Commission in the above-captioned docket notice when the new maximum vessel capacity limit becomes effective; and

5. That BHIT shall provide notice of this change by posting a copy of this Order at the Deep Point and Bald Head Island ferry terminals and on the Bald Head Island website, send mass e-mails to island property owners, and inform passengers who call to make ferry reservations.

ISSUED BY ORDER OF THE COMMISSION.
This the 9th day of October, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioners Lyons Gray and Daniel G. Clodfelter dissent.

DOCKET NO. A-41, SUB 19

Commissioner Daniel G. Clodfelter, dissenting:

I would deny what is in essence BHIT's motion for reconsideration of the Commission's September 23, 2020 Order. BHIT offers no new or changed circumstances or considerations warranting reversal of that order. Movant's invocation of Executive Order No. 169 (EO 169), issued by the Governor on September 30, 2020, is unavailing, and the motion papers misstate what the Executive Order actually says. Because the Commission should be guided in large part by the restrictions imposed therein, I respectfully dissent.

EO 169 maintained many of the restrictions on meetings and gatherings put in place by earlier executive orders. It again provided that slowing and controlling community spread of COVID-19 remains critical. EO 169 not only maintained many of the restrictions placed upon certain business and social settings but recognized that in spite of "recent modest declines" and some evidence of stabilization, "COVID-19 daily case counts and associated hospitalizations are [nevertheless] above their levels on May 20, 2020, when the state announced Phase Two of COVID-19 restrictions and reopening." In continuing to support a "Need for a Phased, 'Dimmer Switch' Approach to Loosening Restrictions," EO 169 emphasized that the stabilization of North Carolina's key metrics is fragile, and thus gave several reasons for "necessitating that the state exercise caution in loosening restrictions (particularly in high-risk settings)."

Admittedly, EO 169 lifted certain restrictions on several entertainment venues, for example, amusement parks, bars, arenas, movie theaters, et al. In doing so, however, EO 169 imposed several restrictions upon these businesses, including, among other things, face covering requirements, measures to ensure that people remain socially distanced, and cleaning requirements. It also imposed upon these businesses certain capacity limitations, including that guests in indoor or outdoor areas must be limited to *the lesser of*:

- 100 people for the total area or room;
- 30% of the facility's or area's stated capacity; or
- no more than 7 guests for every 1000 square feet of the area's square footage.

EO 169 also did not change EO 163's prohibition on "Mass Gatherings" of more than 25 people indoors or more than 50 people outdoors at the same time in a single confined indoor or outdoor space.

BHIT's misreading of the Executive Order is not a proper ground for granting its motion. And because BHIT has not shown that its request – to modify the ferry vessel capacity limit to allow a maximum of 100 passengers -- meets *the lesser of* the above metrics, I would deny BHIT's motion.

Commissioner Lyons Gray joins in this dissent.

DOCKET NO. E-2, SUB 1224
DOCKET NO. E-7, SUB 1233
DOCKET NO. G-9, SUB 763

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Joint Petition of Duke Energy Progress, LLC,	)	ORDER APPROVING
Duke Energy Carolinas, LLC, and Piedmont	)	DEFERRAL ACCOUNTING
Natural Gas Company, Inc., for an Accounting	)	WITH CONDITIONS
Order Related to Settlement Accounting of	)	
Pension Expenses	)	

BY THE COMMISSION: On January 17, 2020, Duke Energy Progress, LLC, Duke Energy Carolinas, LLC, and Piedmont Natural Gas Company, Inc. (collectively Petitioners), filed a Joint Petition for an Accounting Order (Petition) in the above- captioned dockets. In summary, Petitioners requested that the Commission issue an accounting order authorizing them to record certain pension plan settlement accounting impacts in regulatory asset or regulatory liability accounts, and to amortize those assets or liabilities in the same manner that they would have been amortized had the settlement accounting not occurred. Petitioners stated that this would not involve a change to any of Petitioners' retail rates or prices, and would not require any change in a Commission rule, regulation, or policy. According to Petitioners, the accounting treatment that they seek is consistent with the amounts that are already included in customers' current rates and the amount that would have been expensed but for the pension plan settlements. Further, Petitioners stated that the requested change simply allows Petitioners' to align the expenses with the revenues that are being collected from customers. In addition, they stated that the right of any party to address the prudency of Petitioners' pension costs in a future general rate case would not be prejudiced by the requested accounting treatment.

Petitioners explained that they maintain a regulatory asset or regulatory liability on their books associated with pension costs that includes actuarial losses or gains. The losses or gains are created when the pension plans' actual experience differs from assumed experience. In 2006, the Financial Accounting Standards Board issued Financial Accounting Standard (FAS) 158. Petitioners stated that FAS 158 requires that they record their actuarial losses or gains in an account entitled Accumulated Other Comprehensive Income, and that by Order issued in Docket Nos. E-100, Sub 112 and G-9, Sub 545 (FAS 158 Order), the Commission granted their request to be allowed to defer the impacts of FAS 158 by recording the actuarial losses or gains as regulatory assets or liabilities.

Petitioners explained that generally accepted accounting principles in pension accounting includes a provision that can trigger an acceleration of the expensing of actuarial losses or gains if the lump sum benefit payments from a pension plan in a year exceed a certain threshold amount. This threshold amount is based on each Petitioner's annual pension plan service cost and interest cost. The acceleration of the expense is referred to as settlement accounting. Petitioners stated that in 2018 they reduced their number of employees, and that many of those employees chose to take lump sum payments from the pension plan in 2019. As a result, it was determined in the second quarter of 2019 that lump sum payments probably would exceed the threshold amount. Thus, in the second quarter of 2019 Petitioners triggered the settlement accounting provision and booked settlement accounting entries in the second, third and fourth quarters of 2019. The settlement amounts are approximately as follows:

	Settlement Charges			
	Q2	Q3	Q4	YTD
DEC	$43 M	$6 M	$4 M	$53 M
DEP	$16 M	$3 M	$1 M	$20 M
Piedmont	$3 M	$3 M	$2 M	$8 M

Petitioners stated that in order to continue to match the pension plan expenses with the amounts included in customer rates, they are requesting approval to record the expense related to actuarial losses or gains in the same way they would have been expensed absent the 2019 settlement accounting, and to record the difference to regulatory asset or regulatory liability accounts. Petitioners stated that this is similar to the relief granted by the Commission in the FAS 158 Order.

In conclusion, Petitioners stated that they anticipate future settlement accounting amounts because they have closed their pension plans to new employees, which means that the threshold amounts for triggering the settlement accounting will continue to decrease. Petitioners stated that they will submit a separate petition or petitions for the requested accounting treatment for future settlement events. Finally, they stated that absent the requested relief they will be required to recognize expense or income impacts to their financial statements that are lumpy and irrational and are not aligned with current customer rates.

On January 27, 2020, the Commission issued an Order allowing interested parties to intervene in this proceeding, and requesting comments and reply comments on Petitioners' proposal.

On March 11, 2020, the Public Staff filed initial comments. In summary, the Public Staff stated that it reviewed the two-prong test typically applied by the Commission for assessing cost deferral requests and concluded that there are situations in which deferral may be justified even though the costs involved would not otherwise meet the requirements of the two-prong test. The Public Staff cited as such an example the deferral and amortization in a manner that is consistent with the way rates are normally set by the Commission. The Public Staff opined that although the size of the costs may be a factor in such a situation, it may not be a primary factor.

The Public Staff stated that it believes that Petitioners' deferral request is justified in this case of pension settlement costs because the deferral of the pension settlement costs is consistent with how actuarial gains and losses have been treated in past general rate cases, and how they are proposed to be treated in DEC's and DEP's currently pending rate cases in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219, respectively. In addition, the Public Staff stated that it agrees with

Petitioners' commitment to submit separate petitions for deferral requests related to future pension settlement events.

The Public Staff recommended that the Commission approve the deferral accounting treatment requested by Petitioners for the 2019 triggered pension settlement accounting entries with the following conditions: (1) that for North Carolina retail regulatory accounting purposes Petitioners record the income statement and rate base effects of the deferral of the 2019 triggered pension settlement and the amortization of said deferred costs in a manner consistent with the way that the settlement costs would have been amortized for North Carolina retail regulatory accounting purposes had no triggering of an acceleration of the recognition of expenses under GAAP occurred; (2) that such deferrals be recorded consistent with the Commission's orders in Docket Nos. E-100, Sub 112 and G-9, Sub 545; (3) that approval of this accounting procedure be made without prejudice to the right of any party to take issue with the amount of or the ratemaking treatment accorded these costs in any future regulatory proceeding; and (4) that the Commission's decision on deferral and amortization of the 2019 triggered pension settlement accounting entries be effective for the impacts of the 2019 event only, and not be relied on as precedent for future equivalent or similar deferrals without prior Commission approval.

On March 18, 2020, Petitioners filed a letter stating that they have no objection to the Public Staff's recommendations.

Based on the foregoing and the record, the Commission finds good cause to approve Petitioners' requested deferral accounting treatment for the 2019 triggered pension settlement accounting entries subject to the conditions recommended by the Public Staff, as enumerated in the body of this Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of May, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-2, SUB 931
DOCKET NO. E-7, SUB 1032

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 931 In the Matter of Application of Duke Energy Progress, LLC, for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to N.C.G.S. § 62-133.9 and Commission Rule R8-69 DOCKET NO. E-7, SUB 1032 In the Matter of Application of Duke Energy Carolinas, LLC, for Approval of New Cost Recovery Mechanism and Portfolio of Demand-Side Management and Energy Efficiency Programs	ORDER APPROVING REVISIONS TO DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY COST RECOVERY MECHANISMS

BY THE COMMISSION: On January 20, 2015, the Commission issued an Order Approving Revised Cost Recovery Mechanism and Granting Waivers (DEP Mechanism Order), in Docket No. E-2, Sub 931 (Sub 931). The DEP Mechanism Order approved changes to the demand-side management and energy efficiency (DSM/EE) mechanism by which Duke Energy Progress, LLC (DEP) recovers its DSM/EE costs and incentives (DEP Mechanism). In Ordering Paragraph No. 7, the Commission directed

> That the Public Staff shall initiate a formal review of the Company's Mechanism not later than February 1, 2019, unless requested to do so earlier by the Commission, the Company, or another interested party. The Public Staff's review should specifically address whether the incentives in the Commission-approved Mechanism are producing significant DSM and EE results; whether the customer rate impacts from the DSM/EE rider are reasonable and appropriate; whether overall portfolio performance targets should be adopted; and any other relevant issues that may be identified during the review process.

DEP Mechanism Order, at 7.

On August 23, 2017, in Docket No. E-7, Sub 1032 (Sub 1032), the Commission issued an Order Approving DSM/EE Rider, Revising DSM/EE Mechanism, and Requiring Filing of Proposed Customer Notice. The Order, among other things, revised the DSM/EE mechanism by which Duke Energy Carolinas, LLC (DEC) recovers its DSM/EE costs and incentives (DEC Mechanism), effective January 1, 2018.

On February 1, 2019, the Public Staff filed a Motion to Establish Comment Cycle in Subs 931 and 1032. In summary, the Public Staff recommended that the Commission initiate a review of the DEP and DEC Mechanisms in a joint proceeding, with initial comments due in 120 days and reply comments due 30 days thereafter. In addition, the Public Staff recommended that the parties address the topics specified by the Commission in Ordering Paragraph No. 7 of the DEP Mechanism Order, as well as other relevant issues. Further, the Public Staff recommended that if parties have suggested changes to the DEP Mechanism that those changes be presented by filing a redlined version of the DEP Mechanism filed as Maness Exhibit I on September 4, 2018, in Docket No. E-2, Sub 1174, and a redlined version of the DEC Mechanism filed as Maness Exhibit II on May 22, 2018, in Docket No. E-7, Sub 1164.

On February 6, 2019, the Commission issued an order requesting comments and reply comments addressing possible changes to the DEP and DEC Mechanisms. The order required that initial comments be filed by June 7, 2019, and that reply comments be filed by July 10, 2019. Further, the order specified that the parties' comments and reply comments should address the topics identified in the DEP Mechanism Order, as well as any other relevant issues. After the Commission granted the parties an extension of time, on July 10, 2019, initial comments were filed by the Public Staff and the North Carolina Attorney General's Office (AGO). In addition, initial comments were filed jointly by Natural Resources Defense Council (NRDC), Southern Alliance for Clean Energy (SACE), Sierra Club, South Carolina Coastal Conservation League (SCCCL),[1] and North Carolina Sustainable Energy Association (NCSEA, collectively Joint Commenters).

After the Commission granted extensions of time for the filing of reply comments based on motions citing discussions and negotiations among the Public Staff, DEC, DEP, AGO, and Joint Commenters, on January 15, 2020, the Public Staff filed proposed revisions to the DEP and DEC Mechanisms on behalf of itself, DEC, DEP, AGO, and Joint Commenters (Joint Parties).

JOINT PARTIES' PROPOSED MECHANISM REVISIONS

The Public Staff explained that Joint Parties had participated in a number of meetings, conference calls, and other communications in order to attempt to resolve some or all of the issues identified in the initial comments, and that as a result of their collaboration Joint Parties had agreed to a number of revisions to the Mechanisms. The Joint Parties' filing included an Attachment A showing Joint Parties' proposed revisions to DEC's Mechanism and Attachment B showing Joint Parties' proposed revisions to DEP's Mechanism. The Public Staff stated that many of the proposed changes are not substantive but, rather, make conforming changes to the Mechanisms. In addition, the Public Staff stated that Joint Parties are recommending substantive changes to the Mechanisms that Joint Parties believe are in the public interest and will serve to make the Mechanisms more effective. The Public Staff described the substantive changes as follows.

[1] Sierra Club and SCCCL are parties only in Sub 1032.

- Addition of a Program Return Incentive (PRI) – Joint Parties believe that one central focus of DEC's and DEP's DSM/EE efforts should be to provide low- income customers with tools to lower their electricity bills, and that such focus is consistent with Recommendation I-3 of the North Carolina Clean Energy Plan to "[e]xpand energy efficiency and clean energy programs specifically targeted at underserved markets and low-income communities."[1] Consequently, the Joint Parties developed the PRI, which is an incentive to encourage DEC and DEP to pursue savings from existing and new low-income DSM/EE programs, and to maintain and increase the cost effectiveness of these programs. For these types of programs, the PRI initially will be based on 10.6% of the net present value of the avoided cost savings achieved by these DSM/EE programs. The percentage ultimately used to determine the PRI for each Vintage Year will be based on the Company's ability to maintain or improve the cost effectiveness of the PRI-eligible programs over and above that initially estimated for the Vintage Year. At no time will the PRI percentage fall below 2.65% or rise above 13.25%.

- Reduction of Portfolio Performance Incentive (PPI) Percentage - Currently, the PPI percentages used for DEC and DEP are 11.50% and 11.75%, respectively. Joint Parties propose to reduce the PPI percentages for both Companies to 10.60%.

- Cap and Floor on PPI – Joint Parties propose that the amount of pre-tax PPI allowed will not exceed or fall below the amount that produces a specified margin over the aggregate pre-tax program costs for the PPI-eligible programs. The maximum margin is set at 19.50% for Vintage Year 2022 and afterward, until completion of the next Mechanism review. Additionally, a minimum margin over aggregate pre-tax program costs for PPI eligible programs will be established at 10% for Vintage Year 2022, 6% for Vintage Year 2023, and 2.50% for Vintage Year 2024 and afterward, until completion of the next Mechanism review.

- Non-Energy Benefits – The revisions provide that the Commission will assess whether it is appropriate to use non-energy benefits in the determination of cost-effectiveness under the Total Resource Cost Test (TRC). Joint Parties stated that this change is consistent with Recommendation I-1 of the NC Clean Energy Plan.[2]

- Clarification of the Criteria for Bundling Measures within Programs – This revision requires bundled measures to be consistent with and related to the measure technologies or delivery channels of a program, unless otherwise ordered by the Commission.

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[1] North Carolina Clean Energy Plan, North Carolina Department of Environmental Quality, State Energy Office, October 2019 (NC Clean Energy Plan), at 117-19. *See* https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.

[2] NC Clean Energy Plan 114-15.

- Use of the Utility Cost Test (UCT) – Currently, the TRC is used to calculate the prospective cost-effectiveness of new and ongoing programs. The proposed revisions provide that determination of the cost-effectiveness of new and ongoing programs will be calculated using the UCT.

- Recovery of PPI in Applicable Vintage Year – Currently, DEP has converted its vintage year PPI into a stream of levelized annual payments not to exceed ten years. Under the proposed revisions, after Vintage Year 2021 the PPI will be recovered in the applicable Vintage Year's revenue requirement, though levelized annual payments from prior vintages will continue to be collected until recovered.

- Review of Avoided Transmission and Distribution (T&D) Costs – The Public Staff and DEC or DEP, as applicable, will review the avoided T&D costs no later than December 31, 2021, and make recommendations for any adjustment in the rider proceedings thereafter. Avoided T&D costs will be reviewed at least every three years and will be updated if they change by at least 20%.

- Additional Incentive and Penalty - If the Company achieves annual energy savings of 1.0% of the prior year's system retail electricity sales in any year during 2022 through 2025, the Company will receive an additional incentive of $500,000 for that year. During that same period, if the Company fails to achieve annual energy savings of 0.5% of retail sales, net of sales associated with customers opting out of the Company's EE programs, the Company will reduce its EE revenue requirement by $500,000.

- Minor Modification to DEP Opt-Out Provision - A minor modification was made to the opt-out provisions of the DEP Mechanism that addresses a potential unintended outcome that could occur in the case in which there is rate element of Rider DSM/EE that is a credit.

Joint Parties stated that they spent substantial time considering the costs and benefits of aligning DEC's and DEP's use of amortization for their DSM/EE operations and maintenance (O&M) expenses. They noted that DEC does not amortize these expenses, while DEP generally amortizes post-2015 O&M expenses over five years for residential customers and three years for non-residential customers.[1] According to Joint Parties, they considered several scenarios, using a number of assumptions, to estimate the bill impact of ending or reducing the amortization periods. Their calculations indicated that ending the amortizations for new program costs entirely in 2022, when the revisions to the Mechanisms would go into effect, would result in overall residential bill increases of approximately 2.50% in that year, and increases of approximately 2.25% to 3.00% for different classes of non-residential customers. Reducing the period of amortization to two years

[1] In the initial DEP Mechanism, the amortization period for these expenses was set at a maximum of ten years, and DEP utilized a ten-year period for most programs. In the 2015 revision to DEP's Mechanism, a reduction of amortization periods for O&M expenses incurred in future years was allowed for programs for which those expenses had previously been amortized over longer periods; this provided for the general reduction of those post-2015 cost amortization periods to five or three years. However, for O&M expenses incurred prior to 2016, the originally chosen amortization periods remained in place. For administrative and general (A&G) expenses, from the outset of the Mechanism, the maximum amortization period has been three years.

instead of ending it would decrease the amount of rate increase to approximately 1.00% -1.20% for two years for residential customers and approximately 0.67% - 0.95% for two years for the different classes of non-residential customers. Further, the Joint Parties stated that they reviewed the impact of reducing the amortization period to three years, which they estimated to increase residential bills by approximately 0.50% for three years and non-residential bills by approximately 0.13% for two years. Finally, the Joint Parties' calculations indicated that after a period of time the increase in bills caused by ending or reducing the amortization periods would end, with the duration of the temporary increase varying under each of the scenarios above and by customer rate class from two to seven years.

Joint Parties agreed that aligning the amortization periods for DEP and DEC was a worthy goal. However, Joint Parties were also concerned about the impact of temporary rate increases on customers in light of the application for a rate increase filed by DEP in Docket No. E-2, Sub 1219. To minimize the impact on customer rates but to continue the process of aligning the amortization periods, Joint Parties proposed that the amortization period be reduced to three years in this revision of the DEP Mechanism, and that the parties consider the issue further in the next review of the Mechanisms.

Joint Parties also agreed that if the Commission finds that some level of temporary rate increases is acceptable in order to eliminate or reduce the amortization period to one or two years, that such a change would be feasible and should not have any other adverse consequences.

In addition, Joint Parties reached agreement that DEC and DEP will work with the DSM/EE Collaborative to develop a scope for a one-time study on the market penetration of EE programs with low and moderate income customers (LMI) to be performed by qualified independent third-party EM&V providers. The study will seek to estimate the LMI market penetration of its non-income qualified residential programs, as well as the market penetration of small commercial programs in neighborhoods with high LMI populations. The study will consider customer participation, energy savings, and bill impacts, as well as identifying potential market barriers. In addition, the study will be utilized by DEC and DEP to make recommendations for program enhancements designed to cost effectively increase market penetration in the targeted populations and neighborhoods. Joint Parties further stated that DEC and DEP will seek to file an initial scope and budget for the work with their 2020 rider filings, and upon Commission approval for recovery of study costs, they will have the study completed prior to the cost recovery Mechanism modifications taking effect in 2022.

Joint Parties acknowledged that certain issues were not resolved through negotiation, and stated that Joint Parties had agreed that each party may identify additional recommendations to the Commission in its comments on the proposed revisions to the Mechanisms so long as such additional recommendations do not conflict with Joint Parties' proposed revisions.

Finally, Joint Parties requested that the Commission issue an order allowing parties to file comments and reply comments on the proposed revisions to the Mechanisms and other relevant issues.

RECOMMENDATIONS OF JOINT COMMENTERS

On January 15, 2020, Joint Commenters filed comments stating that they support the proposed revisions filed by Joint Parties. Further, Joint Commenters made four additional recommendations for the Commission's consideration. First, Joint Commenters recommended that the Commission require a change in the discount rate used in the cost effectiveness tests for DSM/EE programs. They stated that presently each Company's weighted average cost of capital (WACC) is used. According to Joint Commenters, the WACC creates an inherent bias towards the objectives of the utility over those of consumers, reflects a shorter rate of time preference than that of the utility's customers or regulators, and does not reflect the cost of capital for DSM/EE resources, which is more akin to expenses. Joint Commenters recommended the use of a low-risk discount rate (in the range of 0% to 3%), that better aligns with customer objectives, reflects the time preference of customers and the Commission, and reflects the "cost of capital" for DSM/EE investments. Further, Joint Commenters stated that the National Standard Practice Manual (NSPM) offers a framework to assist regulatory bodies and jurisdictions in making the discount rate determination,[1] and they recommended that this framework would serve as a useful guide for the Commission in determining whether to require the use of a discount rate different from the utility's WACC.

Second, Joint Commenters recommended that the Commission consider adopting a reporting requirement for customers who opt out of the Companies' DSM/EE programs. They noted that in the rulemaking proceeding to implement Senate Bill 3, the Commission considered whether Rule R8-69 should require customers to make a showing of whether they were pursuing DSM/EE in order to opt out of utility DSM/EE programs, and the Commission decided that it would not do so.[2] Joint Commenters opined that since Commission Rule R8-69 was promulgated the rate of large non-residential customers opting out of the DEC and DEP DSM/EE programs has remained persistently high, noting that in 2018 51% of DEC's North Carolina non-residential load opted out of the Company's EE rider, and 55% of non-residential load opted out of DEP's EE rider. Joint Commenters stated that although the Companies have worked to improve their non-residential program offerings and have implemented other changes aimed at encouraging greater participation by large customers, these steps have not meaningfully reduced opt-outs. Joint Commenters contended that the Commission should evaluate whether it should require the Companies' opt-out customers to report to DEC or DEP their stated and quantifiable goals for the DSM or EE measures they implement at their own expense, as well as the demand and/or energy savings from those measures.

Third, Joint Commenters recommended that the Commission request a report from the Governor's Office on the results of the Clean Energy Plan (CEP) utility business model reform stakeholder process, and use the report to inform a Commission investigation into decoupling. Joint Commenters maintained that lost-revenue adjustment mechanisms (LRAMs) are an inferior

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[1] National Efficiency Screening Project, *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources* (May 2017), available at https://nationalefficiencyscreening.org/national-standard-practice-manual/.

[2] Order Adopting Final Rules, Docket No. E-100, Sub 113 (Feb. 29, 2008) at 128-29.

way to address a utility's inherent disincentive to pursue efficiency savings that will result in lost sales, and that revenue decoupling is an alternative way to remove the utility's disincentive to pursue efficiency savings. Joint Commenters stated that more than a decade has passed since the Commission issued its Senate Bill 3 report on decoupling, in which the Commission determined that, having only issued its rules implementing Senate Bill 3 earlier that year, it was "premature to mandate new major changes to electric utility rate structures before it has been determined whether the incentives under Senate Bill 3 serve their intended purpose and are sufficient."[1] Joint Commenters maintained that the time is right to revisit decoupling as a policy option, and that the Commission could use the information provided by the CEP to launch its analysis.

Fourth, Joint Commenters recommended that the Commission request a copy of the DEQ report on carbon-reduction policy options, and use the report to inform a Commission investigation into whether an Energy Efficiency Resource Standard (EERS) should be adopted in North Carolina. According to Joint Commenters, the CEP includes a recommendation for establishment of an EERS by 2021. They stated that research has shown that an EERS is the single most effective policy to promote energy efficiency savings.[2]

COMMENTS ON JOINT COMMENTERS' RECOMMENDATIONS

On January 16, 2020, the Commission issued an order allowing parties to file comments and reply comments addressing the Joint Parties' proposed revisions to DEC's and DEP's Mechanisms, the additional recommendations of the Joint Commenters, and any other issues deemed relevant to DEC's and DEP's Mechanisms, with comments due by February 17, 2020, and reply comments by March 9, 2020.

On February 17, 2020, the Public Staff and Carolina Utility Customers Association, Inc. (CUCA) filed comments in response to Joint Commenters' recommendations. As a preliminary matter, the Public Staff stated that it strongly endorses the Joint Parties' proposed revisions to DEP and DEC's DSM/EE Mechanisms because the revisions are designed to incentivize the utilities to achieve the most net savings from DSM/EE, while also placing greater emphasis on reaching low income customers who could most benefit from additional opportunities to reduce the costs of their electric utility service. As a result, the Public Staff believes that the revisions are in the public interest and should be approved.

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[1] Report of the North Carolina Utilities Commission to the Governor of North Carolina, the Environmental Review Commission and the Joint Legislative Utility Review Committee Regarding an Analysis of Rate Structures, Policies and Measures to Promote Renewable Energy Generation and Demand Reduction in North Carolina (Sept. 2, 2008) at 46,

https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=3ab9a622-dab8-4f0b-b013-b7f9b99b0ff1.

[2] *Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency*, American Council for an Energy Efficient Economy, at 26 (Sept. 2015)("Of those states with shared net benefits performance incentives in place, seven of them have EERS and five do not. Those with EERS have twice the energy savings relative to sales, and more than double the electric energy efficiency budgetsas a percentage of utility revenue than the states with no EERS or similar policy.").

Further, the Public Staff noted that the recommendations of Joint Commenters would affect all of the investor-owned utilities, including Dominion Energy North Carolina, which is not a party to this proceeding, and that if the Commission considers any of the four recommendations they should be considered in a generic docket, rather than the present dockets that only apply to DEP and DEC.

Low-Risk Discount Rate

The Public Staff stated that the NSPM cited by Joint Commenters recommends that jurisdictions follow six steps in determining the appropriate discount rate:

Step A: Articulate the jurisdiction's applicable policy goals.

Step B: Consider the relevance of a utility's WACC.

Step C: Consider the relevance of the average customer discount rate.

Step D: Consider the relevance of a societal discount rate.

Step E: Consider an alternative discount rate different from the utility, customer, and societal perspective.
Step F: Consider using a low-risk discount rate for EE cost-effectiveness.

The Public Staff opined that Step A, a determination of North Carolina's policy goals, would affect not only DSM/EE but almost every aspect of resource planning. According to the Public Staff, it is not appropriate to consider policy goals and changes to such goals in the context of the limited issue of discount rates. In addition, the Public Staff stated that using the utility's WACC places DSM/EE programs on a level playing field with supply-side resources, and that DEC witness Farmer noted the appropriateness of using the utility's WACC as being consistent with the Company's compensation for generation plant.[1] Further, the Public Staff stated that it would be difficult to quantify the average customer discount rate, as required by Step C, on a customer class level, and likely impossible on an individual customer basis.

With regard to the NSPM suggestion of a low-risk discount rate for EE, the Public Staff acknowledged that the cost of most EE programs are expensed as opposed to capitalized, but stated that this does not justify the use of a low-risk discount rate since DSM/EE programs are not entirely without risk to the Company because program participation rates and energy savings may vary widely from initial projections. In addition, the Public Staff stated that the calculation of a utility's capital structure and return on equity (ROE) to determine the WACC are generally two of the most contentious issues in a general rate case, and there are recognized models - such as the Discounted Cash Flow, Risk Premium, and Capital Asset Pricing models - used to calculate ROEs, as well as many publications from which to obtain comparative statistics for other utilities. According to the Public Staff, there is little guidance on how to calculate a discount rate directed to the customers'

[1] The recommended discount rate is addressed in the testimony of DEC witness Stephen M.Farmer filed in Docket No. E-7, Sub 831, on April 4, 2008, pp. 13-16.

time and risk preferences, and the Public Staff cited cautionary language in the NSPM about several factors that are subject to change.

Finally, the Public Staff stated that using a lower discount rate would likely result in higher incentive payments to the utility under both the current and proposed Mechanisms because the cost effectiveness of the programs would increase, which could result in a windfall for the utility in the form of increased incentives without a corresponding increase in DSM/EE program participation or energy savings.

Reporting Requirement for Opt-Out Customers

Public Staff's Comments

The Public Staff agreed with the Joint Commenters that the number of opt out customers has had a significant impact on the non-residential DSM/EE programs and riders. On the other hand, the Public Staff stated that it is aware of many industrial and commercial customers that have opted out and have implemented EE measures at their own expense. In addition, the Public Staff noted that the statute does not require such reports, and that the Public staff does not support a reporting requirement, but encourages the utilities and the Collaborative to work to develop cost-effective programs and measures that would reduce opt-outs. Moreover, the Public Staff cited the following statement from the Commission's February 29, 2008 Order Adopting Final Rules, in Docket No. E-100, Sub 113:

> The Commission concludes that Rule R8-69 should not be revised to include either Duke's proposal to require a "substantially equivalent" test in order for customers to opt out of DSM and EE programs or ED, SACE and SELC's proposal that customers desiring to opt out be required to provide detailed descriptions of measures evaluated and measures implemented or planned together with quantified results and projections of the impact of the measures. Senate Bill 3, in general, and G.S. 62-133.8(f), in particular, do not contain any requirement that DSM or EE programs implemented by the customer or DSM or EE programs proposed to be implemented by the customer must be substantially equivalent to the programs or measures being supplied by the electric power supplier. Nor does Senate Bill 3 require customers desiring to opt out to provide detailed descriptions of measures evaluated and measures implemented or planned together with quantified results and projections of the impact of the measures. All that is required of a program used as the basis for a customer's decision to opt out is that: (1) the program have been implemented in the past or (2) that it be proposed to be implemented in the future in accordance with stated, quantified goals.

Order Adopting Final Rules (SB 3 Rules Order), at 129.

The Public Staff stated that there are no changed circumstances since 2008 that necessitate re-litigation of this matter.

CUCA's Comments

CUCA stated that there is no opt out reporting requirement contained in N.C.G.S. § 62-133.9(f), and contended that imposing such a reporting requirement would require a change in the statute. CUCA stated that representatives of CUCA, DEP, DEC, and other stakeholders, including a number of the Joint Commenters, were involved in the lengthy process of developing Senate Bill 3 in which the opt-out provision was negotiated. Further, CUCA noted that neither DEP nor DEC has ever required industrial customers wishing to exercise their opt-out rights to provide notice or information other than what is required under the statute, and that CUCA's members would consider a requirement to report their DSM/EE measures and savings to be a violation of their right to protect their confidential trade secret information from public disclosure. In addition, CUCA contended that following Joint Commenters' recommendation to undertake a process to develop a reporting requirement would be beyond the scope of the statute, the Commission's rules, and the stakeholder process that led up to the opt-out provision.

CUCA also noted that in 2018 51% of DEC's nonresidential load opted out of the DEC DSM/EE Rider, and 55% of DEP's non-residential load opted out, and opined that this results in a "glass half full," rather than half empty, as the situation is viewed by Joint Commenters. Moreover, CUCA cited a recent news report in which Forrest Bradley- Wright, Energy Efficiency Director for SACE, stated that "Duke Energy is far and away the energy efficiency leader [in the region]," and that SACE reported that North Carolina is the only Southeastern state to exceed the national average in EE savings.

Further, CUCA stated that if it is cost effective for a business to invest capital in a DSM or EE project, then the business will choose to make such investments, but a company should not be forced to invest in Duke's DSM/EE programs if such investment does not make economic sense for the company.

Finally, CUCA responded to Joint Commenters' contention that the lack of reporting by opt-out customers inhibits DEC's and DEP's ability to plan for meeting their customers' electric power needs. CUCA stated that DEC and DEP have not identified in their Integrated Resource Plans a lack of opt-out customer data as an impediment to system demand and energy planning.

Investigation of Decoupling

The Public Staff noted that investigations of decoupling mechanisms have typically been initiated upon request of the General Assembly, and that decoupling mechanisms for gas, water, and electric utilities have resulted from legislative action. In addition, the Public Staff opined that the recovery of net lost revenues is a type of decoupling, and stated that such recovery is allowed by statute and has been part of the DSM/EE rider proceedings since their initiation. Further, the Public Staff disagreed with Joint Commenters' view that the current method used for recovery of net lost revenues is "cumbersome and difficult to administer", noting that the Public Staff has been able to navigate the methodology.

Adoption of an Energy Efficiency Resource Standard

The Public Staff stated that performance targets are included in the proposed Mechanisms for DEC and DEP, that an EERS is a mandate more than a target, and that such a mandate would need to come from the General Assembly.

DISCUSSION

Pursuant to N.C.G.S. § 62-133.9(d), the Commission is authorized to approve an annual rider to the rates of electric public utilities to recover all reasonable and prudent costs incurred for the adoption and implementation of new DSM and EE programs. Under the statute DSM/EE costs include, but are not limited to, capital costs - including costs of capital and depreciation expense - administrative costs, implementation costs, incentive payments to participants, and operating costs. In addition, the statute authorizes the Commission to approve incentives for the utility for the adoption and implementation of new DSM and EE programs, including Net Lost Revenues (NLR) and appropriate rewards based on the sharing of savings achieved by the programs. The annual DSM/EE rider is composed of two parts: (1) the utility's forecasted costs, along with incentives, during the rate period, and (2) an experience modification factor to collect the difference between the utility's actual reasonable and prudent costs and incentives incurred during the test period and actual revenues realized during the test period.

The present proceeding is the third review of DEC's Mechanism since it was initially approved in 2010 in Docket No. E-7, Sub 831, and the second review of DEP's Mechanism since it was initially approved in 2009 in Docket No. E-2, Sub 931. The Commission thanks the parties for their efforts in this proceeding and the cooperative spirit in which they have worked. Joint Parties' proposal includes a number of substantial revisions to DEC's and DEP's Mechanisms and evidences a comprehensive review by Joint Parties. One item that Joint Parties left open and expressly requested the Commission's consideration of is whether the amortization periods used by DEP for its DSM/EE O&M expenses - five years for residential customers and three years for non- residential customers – should be eliminated altogether to align with DEC's practice of not amortizing O&M, or whether DEP's amortization of O&M should be phased out over a period of years to reduce the rate impact on customers. Joint Parties included a three- year amortization period in DEP's proposed revised Mechanism, with the recommendation that the matter be considered again in the next review of the Mechanisms, but also agreed that the Commission could find it acceptable to eliminate the amortization period, or reduce it to one or two years. The Commission concludes that the three-year amortization period for DEP's O&M expenses is reasonable at this time and should be approved, with the matter to be further considered in the next Mechanism review proceeding.

The Commission commends the Joint Parties on the proposed revisions to paragraph numbers 87 and 93 of the DEC and DEP Mechanisms, respectively. These paragraphs provide for an additional incentive or a penalty relating to the attainment or non-attainment of a designated percentage of annual energy savings. If the Company achieves annual energy savings of 1.0% of the prior year's system retail electricity sales in any year during 2022 through 2025, the Company will receive an additional incentive of $500,000 for that year. During that same period, if the Company fails to achieve annual energy savings of 0.5% of retail sales, net of sales associated with customers opting out of the Company's EE programs, the Company will reduce its EE revenue requirement by$500,000. The Commission encourages the parties to consider a step approach which could incrementally increase the incentive for additional energy savings and increased penalties for non-attainment of certain milestones over the three-year period. Thus, the Commission directs the Collaborative to study ways to implement a step approach to this type of incentive/penalty structure to potentially achieve even greater annual energy savings. The Commission directs the Public Staff to include a report on the discussions and conclusions reached by the Collaborative on this matter in the next Mechanism review.

With respect to Joint Commenters' recommendation of a low-risk discount rate for DSM/EE programs, the Commission agrees with the Public Staff's observation that an investigation into a low-risk discount rate using the NSPM guidelines recommended by Joint Commenters would be a complex and largely uncharted process. While the Commission agrees that there are differences in a utility's costs and risks of building and operating generating plants compared to implementing DSM/EE programs, there are also differences in the costs and risks of building and operating all of the different assets that comprise the rate base of an integrated electric utility. Traditional ratemaking addresses this fact by assigning a WACC which reflects the risks of the rate base as a whole. The Commission is persuaded that it is necessary to use the utility's WACC in order to place DSM/EE programs "on a level playing field with supply-side resources," as suggested by the Public Staff. Further, the Commission agrees with the Public Staff that, "determination of North Carolina's policy goals as required by Step A [of the NPSM guidelines] would be an immense undertaking far beyond the confines of DSM/EE." However, notwithstanding the foregoing, the Commission concludes that there may be merit in studying the concept of a low-risk discount rate for DSM/EE programs and, therefore, finds good cause to direct that the Collaborative to study this issue. Further, the Commission directs the Public Staff to include a report on the discussions and conclusions reached by the Collaborative on this matter in the next Mechanism review.

With regard to the Joint Commenters' recommendation that the Commission institute a reporting requirement for opt-out customers, the Commission agrees with the Public Staff that consideration of an opt-out reporting requirement is beyond the scope of this proceeding. The opt-out provision is a factor in determinations by industrial and large commercial customers about whether to participate in the utilities' DSM/EE programs. But it has little or nothing to do with the guidelines by which the utilities recover their DSM/EE costs and the incentives they receive for successfully operating such programs. Further, the Commission is not persuaded that there is any basis for reviewing or modifying its decision in the SB 3 Rules Order declining to adopt a reporting requirement.

Joint Commenters further recommended that the Commission initiate a generic proceeding to investigate the adoption of rate decoupling. The Public Staff opined that rate decoupling is more appropriately a matter for the General Assembly. In that context, the Commission notes that HB 624 on multi-year rate plans for electric utilities, presently pending in the General Assembly, has received considerable debate. The Commission concludes that if the legislature is inclined to do so it could include consideration of decoupling in its deliberations on major changes in electric rate structures.

Finally, Joint Commenters recommended that the Commission initiate an investigation into whether an EERS should be adopted in North Carolina. As the Public Staff noted, performance targets are included in the revised Mechanisms but, unlike an EERS, performance targets do not mandate that DEC and DEP achieve a particular level of DSM/EE savings. An EERS would have rate-making implications that go beyond the guidelines for DEC's and DEP's recovery of costs and incentives under N.C.G.S. § 62-133.9. Indeed, Joint Commenters' concerns about a high percentage of large-load commercial and industrial customers opting out of utility-sponsored DSM/EE programs would be exacerbated by an EERS mandate absent a corresponding ability to equitably spread the costs among all ratepayer classes. As a result, the Commission is not persuaded that an investigation into an EERS would be a wise use of the Public Staff's and the Commission's resources at this time.

CONCLUSION

Based on the foregoing and the record, the Commission finds and concludes that the revised Mechanisms proposed by the Joint Parties provide a workable and reasonable methodology for DEC's and DEP's recovery of DSM/EE program costs and appropriate incentives. In addition, the Commission finds and concludes that the revised Mechanisms will result in just and reasonable rates and will serve the public interest. Therefore, the Commission concludes that the revised Mechanisms should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the revised DEC and DEP Mechanisms proposed by the Joint Parties, attached hereto as Appendices A and B, respectively, shall be, and are hereby, approved;

2. That the attached Mechanisms shall be effective for DSM and EE costs and utility incentives associated with time periods beginning on and after January 1, 2022;

3. That the DSM/EE Collaborative shall study ways to implement a step approach to the incentive/penalty structure adopted by the Joint Parties to potentially achieve even greater annual energy savings and in the next Mechanism review the Public Staff shall include in its initial filing a report on the discussions and conclusions reached by the Collaborative on this matter;

4. That the DSM/EE Collaborative shall study the concept of a low-risk discount rate in assessing the cost effectiveness of the electric public utilities' DSM/EE programs, and in the next Mechanism review the Public Staff shall include in its initial filing a report on the discussions and conclusions reached by the Collaborative on this matter;

5. That DEC and DEP shall work with the DSM/EE Collaborative to develop a scope for a one-time study on the market penetration of EE programs with low and moderate income customers to be performed by qualified independent third-party EM&V providers, as more fully described in the body of this Order. DEC and DEP shall seek to file an initial scope and budget for the work with their 2020 rider filings, and upon Commission approval for recovery of study

costs, they shall have the study completed prior to the cost recovery Mechanism modifications approved herein taking effect in 2022; and

6. That the Public Staff shall initiate a joint formal review of DEC's and DEP's Mechanisms not later than May 1, 2024, unless requested to do so earlier by the Commission, DEC or DEP, or another interested party. The Public Staff's review should specifically address whether the incentives in the Commission-approved Mechanisms are producing significant DSM and EE results; whether the customer rate impacts from the DSM/EE rider are reasonable and appropriate; whether overall portfolio performance targets should be adopted or revised; and any other relevant issues that may be identified during the review process.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of October, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

Commissioners Daniel G. Clodfelter and Jeffrey A. Hughes concur in a separate opinion.
Commissioner Floyd B. McKissick, Jr., did not participate in this decision.

DOCKET NO. E-2, SUB 931
DOCKET NO. E-7, SUB 1032

Commissioner Daniel G. Clodfelter, concurring: I support the Commission's Order so far as it goes. The adjustments agreed upon and proposed by the Joint Parties are useful, albeit modest. We are now approximately thirteen years out from the enactment of N.C.G.S. § 62-133.9, and for myself I think a more substantial review and revision of the DSM/EE mechanisms is due. In particular, I believe it would have been valuable for the Commission in these dockets to have given serious consideration to adopting the recommendation of the Attorney General's expert, Strategen Consulting. Several commenters have noted that the success of the energy efficiency and demand side management programs proposed and approved to date does not necessarily portend equivalent future success. Put differently, they say the "low-hanging fruit" has by now substantially all been harvested. I am concerned they will prove to be correct. In Paragraph 6 of its Order the Commission directs that the next formal review of the DSM/EE mechanisms is to be initiated "not later than" May 1, 2024, subject to the condition that the Commission may initiate such a review sooner on its own motion or upon motion of an interested party. For me, I say sooner rather than later.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

Commissioner Jeffrey A. Hughes, concurring:

Like Commissioner Clodfelter, I support the Commission's Order. I join with Commissioner Clodfelter in his concurrence, and emphasize his statements about conducting a more substantial review of the DSM/EE mechanisms sooner rather than later.

/s/ Jeffrey A. Hughes
Commissioner Jeffrey A. Hughes

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COST RECOVERY AND INCENTIVE MECHANISM OF DUKE ENERGY CAROLINAS, LLC, FOR DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS

(Docket No. E-7, Sub 1032, as Modified by the Commission, to be Effective January 1, 2022)

The purpose of this Mechanism is to (1) allow Duke Energy Carolinas, LLC (Duke Energy Carolinas or the Company), to recover all reasonable and prudent costs incurred for adopting and implementing new demand-side management (DSM) and new energy efficiency (EE) measures in accordance with N.C. Gen. Stat. § 62-133.9, Commission Rules R8-68 and R8-69, prior Orders of the Commission, and the additional principles set forth below; (2) establish certain requirements, in addition to those of Commission Rule R8-68, for requests by Duke Energy Carolinas for approval of DSM and EE programs; (3) establish the terms and conditions for the recovery of Net Lost Revenues and a Portfolio Performance Incentive (PPI) to reward Duke Energy Carolinas for adopting and implementing new DSM and EE measures and programs in cases where the Commission deems such recovery and reward appropriate, and (4) provide for an additional incentive to further encourage kilowatt-hour (kWh) savings achievements. The definitions set out in N.C. Gen. Stat. § 62-133.8 and N.C. Gen. Stat. § 62-133.9 and Commission Rules R8-68 and R8-69 apply to this Mechanism. For purposes of this Mechanism, the definitions listed below also apply.

Changes in the terms and conditions of this Mechanism shall be applied prospectively only, to vintage years following any Commission order amending these terms and conditions. Approved programs and measures shall continue to be subject to the terms and conditions that were in effect when they were approved with respect to the recovery of reasonable and prudent costs and Net Lost Revenues. With respect to the recovery of the PPI, approved programs and measures shall continue to be subject to the terms and conditions in effect in the vintage year that the measurement unit was installed.

ELECTRIC – ADJUSTMENTS OF RATES/CHARGES

Definitions

1. *Common costs* are costs that are not attributable or reasonably assignable or allocable to specific DSM or EE programs but are necessary to design, implement, and operate the programs collectively.

2. *Costs* include program costs (including those of pilot programs approved by the Commission for inclusion in the Mechanism), common costs, and, subject to Rule R8-69(b), any other costs approved by the Commission for inclusion in the Mechanism. *Costs* include only those expenditures appropriately allocable to the North Carolina retail jurisdiction.

3. *Low-Income Programs or Low-Income Measures* are DSM or EE programs, or DSM or EE measures approved by the Commission as programs or measures provided specifically to low-income customers.

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4. *Measure* means, with respect to EE, an "energy efficiency measure," as defined in N.C. Gen. Stat. § 62-133.8(a)(4), that is new under G.S. 62- 133.9(a); and, with respect to DSM, an activity, initiative, or equipment, physical, or program change, that is new under N.C. Gen. Stat. § 62- 133.9(a) and satisfies the definition of "demand-side management" as set forth in N.C. Gen. Stat. § 62-133.8(a)(2).

5. *Measurement unit* means the basic unit that is used to measure and track the (a) incurred costs; (b) Net Lost Revenues; and (c) net kilowatt (kW), kWh, and dollar savings net of Net-to-Gross (NTG) for DSM or EE measures installed in each vintage year. A measurement unit may consist of an individual measure or bundles of measures. Measurement units shall be requested by Duke Energy Carolinas and established by the Commission for each program in the program approval process, and shall be subject to modification by the Commission when appropriate. If measurement units have not been established for a particular program, the measurement units for that program shall be the individual measures, unless the Commission determines otherwise.

6. *Measurement unit's life* means the estimated number of years that equipment or customer treatment associated with a measurement unit will operate if properly maintained or activities associated with the measurement unit will continue to be cost-effective, and produce energy (kWh) or peak demand (kW) savings, unless the Commission determines otherwise.

7. *Net Found Revenues* means any increases in revenues resulting from any activity by Duke Energy Carolinas' public utility operations that causes a customer to

increase demand or energy consumption, whether or not that activity has been approved pursuant to Rule R8-68. The dollar value of Net Found Revenues will be determined in a manner consistent with the determination of the dollar value of NLR provided in Paragraph No. 8 below. In determining which activities constitute Net Found Revenues, the "decision tree" adopted by Order in Docket No. E-7, Sub 831 on February 8, 2011, should be applied. Net Found Revenues may be reduced, if such reduction is approved as reasonable and appropriate by the Commission, by a decrease in revenues resulting from an activity by Duke Energy Carolinas' public utility operations that causes a customer to reduce demand or energy consumption (negative found revenues). To be approved, it must be demonstrated that the activity producing the negative found revenues reduces the profitability of the Company. Additionally, the total amount of Net Found Revenues for a given vintage year will not be reduced to a level below zero by the inclusion of negative found revenues.

8. *Net Lost Revenues* means Duke Energy Carolinas' revenue losses, net of marginal costs avoided at the time of the lost kWh sale(s), or in the case of

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purchased power, in the applicable billing period, incurred by Duke Energy Carolinas' public utility operations as the result of a new DSM or EE measure. A PPI shall not be considered in the calculation of Net Lost Revenues or Net Lost Revenue recovery.

9. *Net-to-gross (NTG) factor* means an adjustment factor used to compute the net kW/kWh savings by accounting for but not limited to such behavioral effects as rebound, free ridership, moral hazard, free drivers, and spillover.

10. *Program* means a collection of new DSM or EE measures with similar objectives that have been consolidated for purposes of delivery, administration, and cost recovery, and that have been or will be adopted on or after January 1, 2007, including subsequent changes and modifications.

11. *Program costs* are costs that are attributable to specific DSM or EE programs and include all appropriate capital costs (including cost of capital and depreciation expenses), common costs, reasonably assignable or allocable administrative and general costs, implementation costs, incentive payments to program participants, operating costs, and evaluation, measurement, and verification (EM&V) costs, net of any grants, tax credits, or other reductions in cost received by the utility from outside parties.

12. *Portfolio Performance Incentive* (PPI) means a utility incentive payment to Duke Energy Carolinas as a bonus or reward for adopting and implementing new (as defined in N.C. Gen. Stat. § 62-133.9(a)) EE or DSM measures and/or Programs. The PPI is based on the sharing of avoided cost savings, net of Program Costs, achieved by those DSM and EE Programs in the aggregate. The PPI is also subject to certain limitations as further set forth in this Mechanism. PPI excludes Net Lost Revenues.

13. *Program Return Incentive* (PRI) means a utility incentive payment to Duke Energy Carolinas for adopting and implementing programs that fail to pass the Utility Cost Test, but are approved by the Commission due to the societal benefit they provide, such as low-income programs. For this type of programs, the PRI will be based on a percentage of the net present value of the avoided costs savings achieved by those DSM and EE Programs. The PRI is subject to certain additional factors and limitations, as further set forth in this Mechanism.

14. *Total Resource Cost* (TRC) *test* means a cost-effectiveness test that measures the net costs of a DSM or EE program as a resource option based on the total costs of the program, including both the participants' costs and the utility's costs (excluding incentives paid by the utility to or on behalf of participants). The benefits for the TRC test are avoided supply costs, i.e., the reduction in generation capacity costs, transmission and distribution costs, and energy costs caused by a load reduction. The avoided supply

costs shall be calculated using net program savings, i.e., savings net of changes in energy use that would have happened in the absence of the program. Non-energy benefits, as approved by the Commission, may be considered in the determination of TRC results. The costs for the TRC test are the net program or portfolio costs incurred by the utility and participants, and the increased supply costs for any periods in which load is increased. All costs of equipment, installation, operation and maintenance (O&M), removal (less salvage value), and administration, no matter who pays for them, are included in this test. Any tax credits are considered a reduction to costs in this test.

15. *Utility Cost Test* (UCT) means a cost-effectiveness test that measures the net costs of a DSM or EE program as a resource option based on the costs incurred by the utility (including incentive costs paid by the utility to or on behalf of participants) and excluding any net costs incurred by the participant. The benefits for the UCT are avoided supply costs, i.e., the reduction in generation capacity costs, transmission and distribution costs, and energy costs caused by a load reduction. The avoided supply costs shall be calculated using net program savings, i.e.,

savings net of changes in energy use that would have happened in the absence of the program. The costs for the UCT are the net program or portfolio costs incurred by the utility and the increased supply costs for any periods in which load is increased. Utility costs include initial and annual costs, such as the cost of utility equipment, O&M, installation, program administration, incentives paid to participants and participant dropout and removal of equipment (less salvage value).

16. *Vintage year* means an identified 12-month period in which a specific DSM or EE measure is installed for an individual participant or group of participants.

Term

17. This Mechanism shall continue until terminated pursuant to Order of the Commission.

Application for Approval of Programs

18. In evaluating potential DSM/EE measures and programs for selection and implementation, Duke Energy Carolinas will first perform a qualitative measure screening to ensure measures are:

(a) Commercially available and sufficiently mature.
(b) Applicable to the Duke Energy Carolinas service area demographics and climate.
(c) Feasible for a utility DSM/EE program.

19. Duke Energy Carolinas will then further screen EE and DSM measures for cost-effectiveness. For purposes of this screening, estimated incremental EM&V costs attributable to the measures shall be included in the measures' costs. With the exception of measures included in Low-Income Programs or other non-cost-effective programs with similar societal benefits as approved by the Commission, an EE or DSM measure with an estimated UCT result less than 1.0 will not be considered further, unless the measure can be bundled into an EE or DSM Program to enhance the overall cost- effectiveness of that program. Measures under consideration for bundling, whether as part of a new Program or into an existing Program, should, unless otherwise approved by the Commission, be consistent with and related to the measure technologies, and/or delivery channels currently offered in the existing Program or to be otherwise offered in the new Program.

20. With the exception of Low-Income Programs or other non-cost-effective programs with similar societal benefits as approved by the Commission, all programs submitted for approval will have an estimated UCT result greater than 1.00. Additionally, for purposes of calculating cost-effectiveness for program approval, consistent with the Commission's Orders in Docket Nos. E-7, Sub 1130 and E-7, Sub 1164, the Company shall use projected avoided capacity and energy benefits specifically calculated for the program, as derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as of the date of the filing for the new program approval. However, for the calculation of the underlying avoided energy credits to be used to derive the program-specific avoided energy benefits, the calculation will be based on the projected EE portfolio hourly shape, rather than the assumed 24x7 100 MW reduction typically used to represent a qualifying facility. For purposes of determining cost-effectiveness, estimated incremental EM&V costs attributable to each program shall be included in program costs. Duke Energy Carolinas will comply, however, with Rule R8- 60(i)(6)(iii), which requires that Duke Energy Carolinas' biennial Integrated Resource Plan, revised as applicable in its annual report, include certain information regarding the measures and programs that it evaluated but rejected.

21. If a program fails the economic test in Paragraph 20 above, Duke Energy Carolinas will determine if certain measures can be removed from the program to satisfy the criteria established in Paragraph 20.

22. Nothing in this Mechanism relieves Duke Energy Carolinas from its obligation to comply with Commission Rule R8-68 when filing for approval

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of DSM or EE measures or programs. As specifically required by Rule R8-68(c)(3)(iii), Duke Energy Carolinas shall, in its filings for approval of measures and programs, describe in detail the industry-accepted methods to be used to collect and analyze data; measure and analyze program participation; and evaluate, measure, verify, and validate estimated energy and peak demand savings. Duke Energy Carolinas shall provide a schedule for reporting the results of this EM&V process to the Commission. The EM&V process description should describe not only the methodologies used to produce the impact estimates utilized, but also any methodologies the Company considered and rejected. Additionally, if Duke Energy Carolinas plans to use an independent third party for purposes of EM&V, it shall identify the third party and include all third-party costs in its filing.

23. For those programs first approved in Duke Energy Carolinas' South Carolina jurisdiction and subsequently in its North Carolina jurisdiction, net dollar savings achieved in the South Carolina jurisdiction will be eligible for consideration of inclusion in the determination of the incentive to be approved by the Commission.

Program Management

24. In each annual DSM/EE cost recovery filing, Duke Energy Carolinas shall perform prospective cost-effective test evaluations for each of its approved DSM and EE programs, (b) perform prospective aggregated portfolio-level cost-effectiveness test evaluations for its approved DSM/EE programs (including any common costs not reasonably assignable or allocable to individual programs), and (c) include these prospective cost- effectiveness test results in its DSM/EE rider application.

25. Consistent with the Commission's Orders in Docket Nos. E-7, Sub 1130 and E-7, Sub 1164, for purposes of calculating prospective cost-effectiveness in each DSM/EE rider proceeding to be used to determine whether a program should remain in the portfolio, the Company shall assess each program by:

    (a) Using projected avoided capacity and energy benefits specifically calculated for each program, as derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as of December 31 of the year immediately preceding the date of the annual DSM/EE rider filing. However, for the calculation of the underlying avoided energy credits to be used to derive the program-specific avoided energy benefits, the calculation will be based on the projected EE portfolio hourly shape, rather than the assumed 24x7

    100 MW reduction typically used to represent a qualifying facility; and,

    (b) Evaluating each cost-effectiveness test using projections of participation, savings, program costs, and benefits for the upcoming vintage year.

26. The parties acknowledge that prospective cost-effectiveness evaluations are snapshots of the program's performance, and that ongoing cost- effectiveness is impacted by many factors outside the Company's control, including but not limited to market and economic conditions, avoided costs, and government mandates. The parties shall continue to work to maintain the cost-effectiveness of its portfolio and

individual programs. However, for any program that initially demonstrates a UCT, determined pursuant to Paragraph 24 above of less than 1.00, the Company shall include a discussion in its annual DSM/EE rider proceeding of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program.

27. For programs that demonstrate a prospective UCT, determined pursuant to Paragraph 24 above, of less than 1.00 in a second DSM/EE rider proceeding, the Company shall include a discussion of what actions it has taken to improve cost-effectiveness. Fluctuations of UCT above and below 1.0 should be addressed on a case by case basis.

28. For programs that demonstrate a prospective UCT, determined pursuant to Paragraph 24 above, of less than 1.00 in a third DSM/EE rider proceeding, the Company shall terminate the program effective at the end of the year following the DSM/EE rider order, unless otherwise ordered by the Commission.

29. The Company will seek to leverage available state and federal funds to operate effective efficiency programs. Its application for such funds will be transparent with respect to the cost, operation, and profitability of programs operated with those funds in a manner consistent with its authorized revenue recovery mechanism. Use of such funds helps offset the participant's project costs and is supplemental to Duke Energy Carolinas' incentives to participants. As such, these funds will not change the impacts or cost-effectiveness of Duke Energy Carolinas' programs as calculated using the UCT. Further, the amount of avoided costs recognized by the Company will not be reduced if participants also use state or federal funds to offset any portion of their project costs.

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Program Modifications

30. Modifications to Commission-approved DSM/EE programs will be made using the Flexibility Guidelines filed on February 6, 2012, in Docket No. E- 7, Sub 831, and approved July 16, 2012, by the Commission. Modifications filed with the Commission for approval will be evaluated under the same guidelines and parameters used in DEC's most recently filed DSM/EE rider proceeding.

31. If under the Flexibility Guidelines Commission approval of a modification is required, the Company shall file a petition prior to the implementation of the program change no later than 30 days prior to the proposed effective date, pursuant to Commission Rule R8-68.

32. If under the Flexibility Guidelines advance notice is required, Duke Energy Carolinas shall file all program changes no later than 45 days prior to the proposed effective date of the change using the Advance Notice Program Modifications Reporting Template (Template). If any party has concern about the proposed program modification, it shall file comments with the Commission within 25 days of the Company's filing.

33. The Company shall file on a quarterly basis using the Template a notification of all program changes that have been made without Commission preapproval or advance notice.

34. Whenever a change in a program or measure goes into effect, the baseline cost effectiveness test results should be reset for the purposes of applying the Flexibility Guidelines to subsequent modifications.

Evaluation, Measurement and Verification

35. EM&V of programs, conducted by an independent third-party using a nationally recognized protocol, will be performed to ensure that programs remain cost-effective. This protocol may be modified with approval of the Commission to reflect the evolution of best practices.

36. EM&V will also include updates of any net-to-gross (NTG) factors related to previous NTG estimates for programs and measures. All of the updated information will be used in evaluating the continued cost-effectiveness of existing programs, but updates to NTG estimates will not be applied retrospectively to measures that have already been installed or programs that have already been completed. If it becomes apparent during the implementation of a program that NTG factors are substantially different than anticipated, the Company will file appropriate program adjustments with the Commission.

37. Pursuant to the EM&V Agreement approved by the Commission in Docket No. E-7, Sub 979, for the Company's EE programs, with the exception of the Non-Residential Smart$aver Custom Rebate Program, initial EM&V results shall be applied retrospectively to the beginning of the program offering to replace initial estimates of impacts. For the purposes of the vintage true-ups, these initial EM&V results will be considered actual results for a program until the next EM&V results are received. The new EM&V results will then be considered actual results going forward and applied prospectively for the purposes of truing up vintages from the first day of the month immediately following the month in which the study participation sample for the EM&V was completed. This EM&V will then continue

to apply and be considered actual results until it is superseded by new EM&V results, if any.

38. EM&V for the Non-Residential Smart$aver Custom Rebate Program does not apply retrospectively and this program shall be trued up based on the actual participants and actual projects undertaken.

Opt-Outs for Industrial Customers and Certain Commercial Customers

39. Pursuant to Commission Rule R8-69(d), commercial customers with annual consumption of 1,000,000 kWh or greater in the billing months of the prior calendar year and all industrial customers may, by meeting certain requirements, elect not to participate in DSM/EE measures for which cost recovery is allowed through the DSM/EE rider and the DSM/EE EMF rider. For purposes of application of this option, a customer is defined as a metered account billed under a single application of a Company rate tariff. For commercial accounts, once one account meets the opt-out eligibility requirement, all other accounts billed to the same entity with lesser annual usage located on the same or contiguous properties are also eligible to opt out of the DSM/EE rider and the DSM/EE EMF rider.

40. Pursuant to the Commission's Orders in Docket No. E-7, Sub 938, eligible non-residential customers may opt out of either or both of the DSM and EE categories of programs for one or more vintage years, as well as opt back into either or both the categories for a later vintage year. If a customer opts back into the DSM category, it cannot opt out again for three years; however, a customer has the freedom to opt in or out of the EE category for each vintage year. Additionally, if a customer opts out of paying the Rider for a vintage year after one or more in which the customer was "opted in"; the Company can charge the customer subsequent DSM/EE and DSM/EE EMF Riders only for those vintage years in which the customer actually <u>participated</u> in a DSM/EE program.

41. Eligible customers may opt out of the Company's EE or DSM programs each calendar year during the annual two-month enrollment period between

November 1 and December 31 immediately prior to a new DSM/EE rider becoming effective on January 1. Eligible new customers have sixty days after beginning service to opt out.

42. In addition to the two month opt out period between November 1 and December 31 prior to the new DSM/EE rider becoming effective, during the first week of March (5 business days), customers who have previously opted out may elect to opt in and participate in EE and/or DSM programs during the remainder of the vintage year.

Any customer choosing to opt in during the March window would be back-billed for the rider amount that they would have paid had the chosen to participate during the November/December enrollment period.

Collaborative

43. Duke Energy Carolinas will continue to conduct quarterly collaborative stakeholder meetings for the purpose of collaborating on new program ideas, reviewing modifications to existing programs, ensuring an accurate public understanding of the programs and funding, reviewing the EM&V process, giving periodic status reports on program progress, helping to set EM&V priorities, providing recommendations for the submission of applications to revise or extend programs and rate structures, and guiding efforts to expand cost-effective programs for low-income customers.

44. The Collaborative should continue to be comprised of a broad spectrum of regional stakeholders that represent a balanced interest in the Company's DSM/EE effort and its impacts, as well as national EE advocates and experts. A third party may facilitate the discussions. The collaborative will continue to determine its own rules of operation, including the process for setting the agendas and activities of the group, consistent with these terms. Members agree to participate in the advisory group in good faith consistent with mutually agreed upon rules of participation. Meetings are open to additional parties who agree to the participation rules.

45. Duke Energy Carolinas will provide information related to the development of EE and DSM to stakeholders in a transparent manner. The Company agrees to disclose program-related data at a level of detail similar to that which it has disclosed in other states or as disclosed by other regulated utilities in the Carolinas. The Company will share all aspects of the development and evaluation of programs, including the EM&V process.

46. At its discretion, the Company may require confidentiality agreements with members who wish to review confidential data or any calculations that could be used to determine the data. Disclosure of this data would harm Duke Energy Carolinas competitively and could result in financial harm to its customers.

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47. Participation in the advisory group shall not preclude any party from participating in any Commission proceedings.

ELECTRIC – ADJUSTMENTS OF RATES/CHARGES

General Structure of Riders

48. All DSM/EE and DSM/EE EMF riders shall be calculated and charged to customers based on the revenue requirements for each separate vintage year. Separate DSM/EE and DSM/EE EMF riders shall be calculated for the Residential customer class and those rate schedules within the Non- Residential customer class that have Duke Energy Carolinas DSM/EE program options in which they can participate. One integrated (prospective) DSM/EE rider and one integrated DSM/EE EMF rider shall be calculated for the Residential class, to be effective each rate year. The integrated Residential DSM/EE EMF rider shall include all true-ups for each vintage year appropriately considered in each proceeding. Pursuant to the Commission's Orders in Docket No. E-7, Sub 938, separate DSM and EE billing factors shall be calculated for the Non-Residential class. Additionally, the Non-Residential DSM and EE EMF billing factors shall be determined separately for each vintage year appropriately considered in each proceeding, so that the factors can be appropriately charged to Non- Residential customers based on their opt-in/out status and participation for each vintage year.

48A. The annual filing date of DEC's DSM/EE rider application, supporting testimony, and exhibits will be no later than 98 days prior to the hearing date prescribed by Commission Rule (currently the first Tuesday of June of each calendar year). Should the Company become aware prior to filing of a determined or possible change in the hearing date, the Company shall strive to file its application and associated documents no later than 98 days prior to the changed hearing date.

48B. DEC shall not request that the annual hearing to consider the proposed DSM/EE and DSM/EE EMF riders be held sooner than 98 days after the filing date of the Company's application, supporting testimony, and Exhibits.

Cost Recovery

49. As provided in Rule R8-69 and N.C. Gen. Stat. § 62-133.9(d), Duke Energy Carolinas shall be allowed to recover, through the DSM/EE rider, all reasonable and prudent costs reasonably and appropriately estimated to be incurred in expenses during the current rate period for DSM and EE programs that have been approved by the Commission under Rule R8-68. As permitted by N.C. Gen. Stat. § 62-133.9(d), any of the Stipulating Parties may propose a procedure for the deferral and amortization in future DSM/EE riders of all or a portion of Duke Energy Carolinas' reasonable and

prudent costs to the extent those costs are intended to produce future benefits.

50. The DSM/EE EMF rider shall reflect the difference between the reasonable and prudent costs incurred during the applicable test period (vintage year) and the revenues actually realized during such test period under the DSM/EE rider then in effect.

51. The cost and expense information filed by Duke Energy Carolinas pursuant to Commission Rules R8-68(c) and R8-69(f) shall be categorized by measurement unit or program, as applicable, and vintage year, consistent with the presentation included in the Company's application.

52. In accordance with Commission Rule R8-69(b)(6), Duke Energy Carolinas may implement deferral accounting for over- and under recoveries of costs that are eligible for recovery through the annual DSM/EE rider. The balance in the deferral account(s), net of deferred income taxes, may accrue a return at the net-of-tax rate of return approved in Duke Energy Carolinas' then most recent general rate case. The methodology used for the calculation of interest shall be the same as that typically utilized for the Company's Existing DSM Program rider proceeding (taking into account any extensions of the EMF measurement period pursuant to Commission Rule R8- 69(b)(2)). Pursuant to Commission Rule R8-69(c)(3), the Company is not allowed to accrue a return on Net Lost Revenues or the PPI.

53. For purposes of cost recovery through the DSM/EE and DSM/EE EMF riders, system-level costs shall be allocated to the North Carolina retail jurisdiction by use of the North Carolina and South Carolina allocation determinants in the following manner (no costs of any approved DSM or EE program will be allocated to the wholesale jurisdiction):

    (a) For EE programs, the costs of each program will be allocated based on the annual energy requirements of North Carolina and South Carolina retail customers (grossed up for line losses), as reflected in the annual cost of service studies.

    (b) For DSM programs, the aggregated costs of DSM programs will be allocated based on the annual summer coincident peak demand of North Carolina and South Carolina retail customers, as reflected in the annual cost of service studies.

54. The allocation factors and inputs used to allocate the estimated rate period costs of DSM and EE programs shall be those drawn from the most recently filed cost of service study at the time the annual cost recovery filing is made. The allocations of

costs shall be trued up at the time that finalized and trued- up costs for a given test period are initially passed through the DSM/EE

EMF, using the most recently filed cost of service study at the time the filing is made (but for no later year than the vintage year being trued up). For subsequent true-ups of that vintage year, the cost of service study used will be the same as that used for the initial true-up.

55. For purposes of recovery through the DSM/EE and DSM/EE EMF riders, the Company's North Carolina retail jurisdictional costs for approved DSM and EE programs and measures shall be assigned or allocated to North Carolina retail customer classes as follows. For EE programs offered to Residential or Non-Residential customers, the North Carolina retail jurisdictional costs will be directly assigned to the customer group to which the program is offered. For DSM programs, the aggregated North Carolina retail jurisdictional cost of those programs will be allocated to the Residential and Non-Residential classes based on the contribution of each class to the North Carolina retail jurisdictional peak demand used to make the jurisdictional allocation. The process of estimating and truing up the class assignments and allocations will be the same as practiced for jurisdictional allocations.

Net Lost Revenues

56. Unless otherwise ordered by the Commission, when authorized pursuant to Rule R8-69(c), Duke Energy Carolinas shall be permitted to recover, through the DSM/EE and DSM/EE EMF riders, Net Lost Revenues associated with the implementation of approved DSM or EE measurement units, subject to the restrictions set out below.

57. The North Carolina retail kWh sales reductions that result from an approved measurement unit installed in a given vintage year shall be eligible for use in calculating Net Lost Revenues eligible for recovery only for the first 36 months after the installation of the measurement unit. Thereafter, such kWh sales reductions will not be eligible for calculating recoverable Net Lost Revenues for that or any other vintage year.

58. Programs or measures with the primary purpose of promoting general awareness and education of EE and DSM activities, as well as research and development activities, are ineligible for the recovery of Net Lost Revenues.

59. In order to recover estimated Net Lost Revenues associated with a pilot program or measure, Duke Energy Carolinas must, in its application for program or measure approval, demonstrate (a) that the program or measure is of a type that is intended to be developed into a full-scale, Commission-approved program or measure, and (b) that it will implement an EM&V plan based on industry-accepted protocols for the program or measure. No pilot program or measure will be eligible for Net Lost Revenue

recovery upon true-up unless it (a) is ultimately proven to have been cost-effective, and (b) is developed into a full-scale, commercialized program.

60. Notwithstanding the allowance of 36 months' Net Lost Revenues associated with eligible kWh sales reductions, the kWh sales reductions that result from measurement units installed shall cease being eligible for use in calculating Net Lost Revenues as of the effective date of (a) a Commission- approved alternative recovery mechanism that accounts for the eligible Net Lost Revenues associated with eligible kWh sales reductions, or (b) the implementation of new rates approved by the Commission in a general rate case or comparable proceeding to the extent the rates set in the general rate case or comparable proceeding are set to explicitly or implicitly recover the Net Lost Revenues associated with those kWh sales reductions.

61. Recoverable Net Lost Revenues shall be calculated in a manner that appropriately reflects the incremental revenue losses suffered by the Company, net of avoided fuel and non-fuel variable O&M expenses.

62. Total Net Lost Revenues as measured for the 36-month period identified in paragraph 57 above shall be reduced by Net Found Revenues during the same periods (offset by any negative found revenues found appropriate and reasonable by the Commission pursuant to the provisions of Paragraph 7 of this Mechanism and other factors deemed applicable by the Commission). The "decision tree" adopted by Order in Docket No. E-7, Sub 831 on February 8, 2011, should be applied for determining what constitutes Net Found Revenues. Duke Energy Carolinas shall closely monitor its utility activities to determine if they are causing a customer to increase demand or consumption, and shall identify and track all such activities with the aid of the "decision tree," so that they may be evaluated by intervening parties and the Commission as potential Net Found Revenues. Net found revenues shall be calculated in an appropriate and reasonable manner that mirrors the calculation used to determine Net Lost Revenues.

63. Recoverable Net Lost Revenues shall ultimately be based on kWh sales reductions and kW savings verified by the EM&V process and approved by the Commission. Recoverable Net Lost Revenues shall be estimated and trued-up, on a vintage year basis, as follows:

(a) As part of the DSM/EE rider approved in each annual cost and incentive recovery proceeding, Duke Energy Carolinas shall be allowed to recover the appropriate and reasonable level of recoverable Net Lost Revenues associated with each applicable program and vintage year (subject to the limitations set forth in this Mechanism), estimated to be experienced during the rate period for which the DSM/EE rider is being set.

(b) Net lost revenues related to any given program/measure and vintage year shall be trued-up through the DSM/EE EMF rider in subsequent annual cost and incentive recovery proceedings based on the Commission-approved results of the appropriate EM&V studies related to the program/measure and vintage year, as determined pursuant to the EM&V Agreement.

(c) The true-up shall be calculated based on the difference between projected and actual recoverable Net Lost Revenues for each measurement unit and vintage year under consideration, accounting for any differences derived from the completed and reviewed EM&V studies, including: (1) the projected and actual number of installations per measurement unit; (2) the projected and actual net kWh and kW savings per installation; (3) the projected and actual gross lost revenues per kWh and kW saved; and (4) the projected and actual deductions from gross lost revenues per kWh and kW saved.

(d) The reduction in Net Lost Revenues due to Net Found Revenues (offset by any approved and applicable negative found revenues) shall be trued up in a manner consistent with the true-up of Net Lost Revenues.

(e) The combined total of all vintage year true-ups calculated in a given year's Rule R8-69 proceeding shall be incorporated into the appropriate DSM/EE EMF billing factor.

64. Recoverable Net Lost Revenues shall be directly assigned to the program and vintage year with which they are associated.

Portfolio Performance Incentive (PPI) and Program Return Incentive (PRI)

65. When authorized pursuant to Rule R8-69(c), Duke Energy Carolinas shall be allowed to collect a PPI and PRI, as each is applicable, for its DSM/EE portfolio for each vintage year, separable into Residential, Non-Residential DSM, and Non-Residential EE categories. The PPI and PRI, as applicable, shall be subject to the restrictions set out below.

66. Programs or measures with the primary purpose of promoting general awareness of and education about EE and DSM activities, as well as research and development activities, are ineligible to be included in the portfolio for purposes of the PPI or PRI calculations.

67. Unless (a) the Commission approves Duke Energy Carolinas' specific request that a pilot program or measure be eligible for PPI or PRI inclusion when Duke Energy Carolinas seeks approval of that program or measure,

and (b) the pilot is ultimately commercialized; pilot programs or measures are ineligible for and the benefits and costs associated with those pilots will not be factored into the calculation of the PPI or PRI.

68. In its annual filing, pursuant to Commission Rule R8-69(f), Duke Energy Carolinas shall file an exhibit that indicates, for each Program or Measure for which it seeks a PPI or PRI, the annual projected and actual utility costs, participant costs, number of Measurement Units installed, per kW and kWh impacts for each Measurement Unit, and per kW and kWh avoided costs for each Measurement Unit, consistent with the UCT, related to the applicable Vintage Year installations that it requests the Commission to approve. Upon its review, the Commission will make findings based on Duke Energy Carolinas' annual filing for each Program or Measure that is included in an estimated or trued-up PPI or PRI calculation for any given Vintage Year.

69. Low-Income programs and other specified societal programs approved with expected UCT results less than 1.00 and other non-cost-effective programs with similar societal benefits as approved by the Commission shall not be included in the portfolio for purposes of the PPI calculation until they demonstrate UCT results greater than 1.00. However, such programs will be eligible for the PRI, if so approved by the Commission, until they demonstrate UCT results greater than 1.00.

70. The PPI shall be based on net dollar savings for Duke Energy Carolinas' DSM/EE portfolio, as calculated using the UCT, on a total system basis. The North

Carolina retail jurisdictional and class portions of the system- basis net dollar savings shall be determined in the same manner as utilized to determine the North Carolina retail jurisdictional and class portions of recoverable system costs.

71. Unless the Commission determines otherwise in an annual DSM/EE rider proceeding, and subject to the factors and limitations set forth elsewhere in this Mechanism, beginning for Vintage Year 2022, the amount of the pre- income-tax PPI initially to be recovered for the entire DSM/EE portfolio for a vintage year shall be equal to 10.60% multiplied by the present value of the estimated net dollar savings associated with the DSM/EE portfolio installed in that vintage year, calculated by DSM/EE program using the UCT (and excluding Low -Income Programs and other specified societal programs). The present value of the estimated net dollar savings shall be the difference between the present value of the annual lifetime avoided cost savings for measurement units projected to be installed in that vintage year and the present value of the annual lifetime program costs for those measurement units. The annual lifetime avoided cost savings for measurement units installed in the applicable vintage year shall be calculated by multiplying the number of each specific type of measurement

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unit projected to be installed in that vintage year by the most current estimates of each lifetime year's per installation kW and kWh savings and by the most current estimates of each lifetime year's per kW and kWh avoided costs. In calculating the forecasted initial PPI it will be assumed that projections will be achieved.

72. Beginning with Vintage Year 2022, the dollar amount of the pre-tax PPI ultimately allowed for each Vintage Year, after true-up pursuant to Paragraph 83 of this Mechanism, shall be no greater than the dollar amount that produces a 19.50% margin over the aggregate pre-tax Program Costs for the Vintage Year of those programs in the Portfolio that are eligible for the PPI. Likewise, the dollar amount of the pre-tax PPI ultimately allowed for each Vintage Year, after true-up pursuant to Paragraph 83 of this Mechanism, shall be no less than the dollar amount that produces the following margins over the aggregate pre-tax Program Costs for the Vintage Year of those programs in the Portfolio that are eligible for the PPI.

Vintage Year 2022:	10.00%
Vintage Year 2023:	6.00%
Vintage Year 2024:	2.50%
Vintage Year 2025 and afterwards, until the next Mechanism review is completed:	2.50%

When making its initial estimates of the PPI pursuant to this Mechanism, Duke Energy Carolinas shall utilize the best and most accurate estimate of the margin and the resulting PPI percentage it can determine at that time.

73. At the outset of the application of this Mechanism, the entire PPI related to a vintage year shall be recoverable in the rate period covering that vintage year (subject to true-up). However, any of the Stipulating Parties may propose a procedure to convert a vintage year PPI into a stream of levelized annual payments not to exceed ten years through Vintage Year 2021,, accounting for and incorporating Duke Energy Carolinas' overall weighted average net-of-tax rate of return approved in Duke Energy Carolinas' most recent general rate case as the appropriate discount rate. After Vintage Year 2021, the PPI will be recovered in the proceedings in which the applicable Vintage Year's revenue requirements are estimated or trued up. Levelized annual payments applicable to Programs in prior vintage periods will continue until all such amounts are recovered.

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74. The PRI shall be based on the gross avoided costs of those programs eligible for the PRI. The North Carolina retail jurisdictional and class portions of the system-basis gross dollar savings shall be determined in the same manner as utilized to determine the North Carolina retail jurisdictional and class portions of recoverable system costs.

75. Unless the Commission determines otherwise in an annual N.C. Gen. Stat. § 62-133.9 DSM/EE rider proceeding, and subject to the factors and limitations set forth in this Mechanism, beginning for Vintage Year 2022 the amount of the pre-income-tax PRI initially to be recovered for Low Income Programs and other specified societal programs not eligible for a PPI shall be a percentage, as determined pursuant to this Mechanism, multiplied by the present value of the estimated gross dollar avoided cost savings associated with the applicable DSM/EE Programs installed in that Vintage Year, used in determination of the UCT. The present value of the estimated gross dollar savings shall be determined in the same manner as used for Programs eligible for the PPI.

76. The percentage used to determine the estimated PRI for each Vintage Year shall be 10.60%. This percentage will be multiplied by the Vintage Year avoided costs projected to be generated by each approved PRI-eligible program. When making its initial estimates of the PRI, DEP shall utilize the best and most accurate estimate of the UCT and the resulting PRI percentage it can determine at that time.

77. For the PPI and PRI for Vintage Years 2019 and afterwards, consistent with the Commission's Orders in Docket Nos. E-7, Sub 1130 and E-7, Sub 1164, the program-specific per kW avoided capacity benefits and per kWh avoided energy benefits used for the initial estimate of the PPI and PRI and any PPI or PRI true-up will be derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent Commission- approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as of December 31 of the year immediately preceding the date of the annual DSM/EE rider filing. However, for the calculation of the underlying avoided energy credits to be used to derive the program-specific avoided energy benefits, the calculation will be based on the projected EE portfolio hourly shape, rather than the assumed 24x7 100 MW reduction typically used to represent a qualifying facility.

78. No later than December 31, 2021, Duke Energy Carolinas and the Public Staff will jointly review the issue of the appropriate avoided T&D costs to be used in the Company's prospective calculations of cost-effectiveness and achieved net dollar savings, and, if appropriate, recommend in the Company's annual DSM/EE rider proceeding adjustments to the avoided T&D cost rates.

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79. The per kW avoided transmission and avoided distribution (avoided T&D) costs used to calculate net savings for a Vintage Year shall be based on the study update at least every three years only if the study update results in a 20% change from the prior study's avoided T&D costs.

80. Unless the Stipulating Parties agree otherwise, Duke Energy Carolinas shall not be allowed to update its avoided capacity costs and avoided energy costs after filing its annual cost and incentive recovery application for purposes of determining the DSM/EE and DSM/EE EMF riders in that proceeding.

81. When Duke Energy Carolinas files for its annual cost recovery under Rule R8-69, it shall comply with the filing requirements of Rule R8-69(f)(1)(iii), reporting all final measurement and verification data to assist the Commission and Public Staff in their review and monitoring of the impacts of the DSM and EE measures.

82. Duke Energy Carolinas bears the burden of proving all dollar savings and costs included in calculating the PPI and PRI. As provided in Rule R8- 68(c)(3)(iii), Duke Energy Carolinas shall be responsible for the EM&V of energy and peak demand savings consistent with its EM&V plan.

83. The PPI and PRI for each vintage year shall ultimately be based on net or gross dollar savings, as applicable, as verified by the EM&V process and approved by the Commission. The PPI and PRI for each vintage year shall be trued-up as follows:

(a) As part of the DSM/EE rider approved in each annual cost and incentive recovery proceeding, Duke Energy Carolinas shall be allowed to recover an appropriately and reasonably estimated PPI and PRI (subject to the limitations set forth in this Mechanism) associated with the vintage year covered by the rate period in which the DSM/EE rider is to be in effect.

(b) The PPI and PRI related to any given vintage year shall be trued-up through the DSM/EE EMF rider in subsequent annual cost and incentive recovery proceedings based on the Commission-approved results of the appropriate EM&V studies related to the program/measure and vintage year, as determined pursuant to the EM&V Agreement.

(c) The PPI amount ultimately to be recovered for a given vintage year shall be based on the present value of the actual net dollar savings derived from all measurement units installed in that vintage year, as associated with each DSM/EE program offered during that year (excluding Low Income Programs and other specified societal

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programs), and calculated by DSM/EE program using the UCT. The present value of the actual net dollar savings shall be the difference between the present value of the annual lifetime avoided cost savings for measurement units installed in that vintage year and the present value of the annual lifetime program costs for those measurement units. The annual lifetime avoided cost savings for measurement units installed in the applicable vintage year shall be calculated by multiplying the number of each specific type of measurement unit installed in that vintage year by each lifetime year's per installation kW and kWh savings (as verified by the appropriate EM&V study pursuant to the EM&V agreement) and by each lifetime year's per kW and kWh avoided costs as determined when calculating the initially estimated PPI for the vintage year. The ultimate PPI will also be subject to the additional factors and limitations set forth in this Mechanism. The

Stipulating Parties agree to make all reasonable efforts to ensure that all vintages are fully trued-up within 24 months of the vintage program year.

(d) The amount of the PRI ultimately to be recovered for a given Vintage Year shall be based on the present value of the actual gross dollar savings derived from all Measurement Units installed in that Vintage Year, as associated with each DSM/EE program offered during that year that is eligible for the PRI. Furthermore, the percentage used to determine the final PRI for each Vintage Year will be based on the Company's ability to maintain or improve the cost effectiveness of the PRI-eligible programs. The PRI percentage for each PRI-eligible Program will be determined by comparing (1) the projected UCT ratio for the portfolio of PRI-eligible Programs for the Vintage Year at the time of the Company's DSM Rider filing first estimating that projected Vintage Year UCT ratio to (2) the actual UCT ratio achieved for that portfolio of PRI-eligible Programs as that Vintage Year is trued up in future filings. The ratio (UCT actual/UCT estimate) will then be multiplied by 10.60% to determine the PRI percentage that will be applied to the actual avoided costs generated by each approved PRI- eligible program. At no time will the PRI percentage utilized fall below 2.65% or rise above 13.25%. The present value of the estimated gross dollar savings shall be determined in the same manner as used for determining the recovery of the ultimate PPI. The ultimate PRI will also be subject to the additional factors and limitations set forth in this Mechanism. The Stipulating Parties agree to make all reasonable efforts to ensure that all vintages are fully trued-up within 24 months of the vintage program year.

(e) A program's eligibility for a PPI or PRI will be determined at the time of filing the projection for a Vintage Year and will continue to be

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eligible for the same incentive at the time of the Vintage Year true- up.

(f) If a program previously eligible for a PRI becomes cost effective under the UCT, it will no longer be eligible to receive a PRI in the next projected Vintage Year for the program, but will be eligible for the PPI.

84. The combined total of all vintage year true-ups of the PPI calculated in a given year's Rule R8-69 proceeding shall be incorporated into the appropriate DSM/EE EMF billing factor.

85. The PRI will be determined on the basis of the avoided costs employed in the determination of the UCT. PRI amounts will be assigned to the Program in which they were earned.

86. The PPI for each vintage year shall be allocated to DSM and EE programs in proportion to the present value net dollar savings of each program for the vintage year, as calculated pursuant to the method described herein.

Other Incentives

87. As further incentive to motivate the Company to aggressively pursue savings from cost-effective EE and DSM Programs, if the Company achieves annual energy savings of 1.0% of the prior year's Duke Energy Carolinas system retail electricity sales, in any year during the four-year 2022-2025 period, the Company will receive an additional incentive of $500,000 for that year. During that same period, if the Company fails to achieve annual energy savings of 0.5% of retail sales, net of sales associated with customers opting out of the Company's EE programs, the Company will reduce its EE revenue requirement by $500,000. Verification of this achievement will be obtained through the EM&V process discussed elsewhere in this Mechanism.

Financial Reporting Requirements

88. In its quarterly ES-1 Reports to the Commission, Duke Energy Carolinas shall calculate and present its primary North Carolina retail jurisdictional earnings by including all actual EE and DSM program revenues, including PPI and Net Lost Revenue incentives, and costs. Additionally, the Company shall prepare and present (a) supplementary schedules setting forth its North Carolina retail jurisdictional earnings excluding the effects of the PPI;(b) supplementary schedules setting forth its North Carolina retail jurisdictional earnings excluding the effects of the Company's EE and DSM programs; and (c) supplementary schedules setting forth earnings, including overall rates of return, returns on common equity, and margins

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over program costs actually realized from its EE and DSM programs in total and stated separately by program class (program classes are hereby defined to be (i) EE programs and (ii) DSM programs). Detailed workpapers shall be provided for each scenario described above. Such workpapers, at a minimum, shall clearly show actual revenues, expenses, taxes, operating income, rate base/investment, including components, and the applicable capitalization ratios and cost rates, including overall rate of return and return on common equity. Net lost revenues realized (estimated, if not known) for each reporting period shall be clearly disclosed as supplemental information.

Review of Mechanism

89. The terms and conditions of this Mechanism shall be reviewed by the Commission every four years unless otherwise ordered by the Commission. The Company and other parties shall submit any proposed changes to the Commission for approval at the time of the filing of the Company's annual DSM/EE rider filing. During the time of review, the Mechanism shall remain in effect until further order of the Commission revising the terms of the Mechanism or taking such other action as the Commission may deem appropriate.

No Precedential Effect

90. The terms of this Mechanism, including the methods and results of determining the PPI and PRI, as well as the other incentives outlined in Paragraph 87, shall not be considered precedential for any purpose other than their application to eligible DSM/EE Programs and cost and utility incentive recovery associated with those Programs, and only until those terms are next partially or wholly reviewed.

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COST RECOVERY AND INCENTIVE MECHANISM OF DUKE ENERGY PROGRESS, LLC, FOR DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS

(Docket No. E-2, Sub 931, as Modified by the Commission, to be Effective January 1, 2022)

Definitions

1. *Common Costs* are administrative and general, or other, costs that are not attributable or directly assignable to specific demand-side management (DSM) or energy efficiency (EE) Programs but are necessary to design, implement, and operate the Programs collectively.

2. *Costs* include program costs (including those of pilot programs approved by the Commission for inclusion in the Mechanism), common costs, and, subject to Rule R8-69(b), any other costs approved by the Commission for inclusion in the Mechanism. *Costs* include only those expenditures appropriately allocable to the North Carolina retail jurisdiction.

3. *Incremental Program Costs* are utility-incurred costs directly attributable and expended solely for a specific DSM or EE Program, and include all appropriate capital costs (cost of capital, depreciation expenses, property taxes, and other

associated costs found reasonable by the Commission), implementation costs, incentive payments to Program participants, other operations and maintenance costs, EM&V costs, and administrative and general costs incurred specifically for the Program, net of any grants, tax credits, or other reductions in cost received by the utility from outside parties and specifically related to the Program.

4. *Low-Income Programs or Low-Income Measures* are DSM or EE Programs or DSM or EE Measures approved by the Commission to be provided specifically to low-income customers.

5. *Measure* means, with respect to EE, an "energy efficiency measure," as defined in N.C. Gen. Stat. § 62-133.8(a)(4), that is new within the meaning of N.C. Gen. Stat. § 62-133.9(a); and, with respect to DSM, an activity, initiative, or Program change, that is new under N.C. Gen. Stat. § 62- 133.9(a) and satisfies the definition of "demand-side management" as set forth in N.C. Gen. Stat. § 62-133.8(a)(2).

6. *Measurement Unit* means the basic unit that is used to measure and track the (a) incurred costs; (b) Net Lost Revenues; and (c) kilowatt (kW), kilowatt-hour (kWh), and dollar savings, net of Net-to-gross (NTG) effects for DSM or EE Measures installed in each Vintage Year. A Measurement Unit may consist of an individual Measure or bundle of Measures. Measurement units shall be requested by Duke Energy Progress (DEP) and established by the Commission for each Program in the Program approval

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process, and shall be subject to modification by the Commission when appropriate. If Measurement Units have not been established for a particular Program, the Measurement Units for that Program shall be the individual Measures, unless the Commission determines otherwise.

7. *Measurement Unit's Life* means the estimated number of years that equipment or customer treatment associated with a Measurement Unit will operate if properly maintained, or activities (services or customer behavior) associated with the Measurement Unit will continue to be cost-effective, and produce energy (kWh) or peak demand (kW) savings, unless the Commission determines otherwise.

8. *Net Found Revenues* means any increases in revenues resulting from any activity by DEP's public utility operations that causes a customer to increase demand or energy consumption, whether or not that activity has been approved pursuant to Commission Rule R8-68. The dollar value of Net Found Revenues will be determined in a manner consistent with the determination of the dollar value of NLR provided in Paragraph No. 9 below. In determining which activities produce

Net Found Revenues, the "Decision Tree" attached to this Mechanism as Attachment C will be applied. Net Found Revenues may be reduced, if such reduction is approved as reasonable and appropriate by the Commission, by a decrease in revenues resulting from an activity by DEP's public utility operations that causes a customer to reduce demand or energy consumption (negative found revenues). To be approved, it must be demonstrated that the activity producing the negative found revenues reduces the profitability of the Company. Additionally, the total amount of Net Found Revenues for a given vintage year will not be reduced to a level below zero by the inclusion of negative found revenues.

9. *Net Lost Revenues (NLR)* means DEP's revenue losses due to new DSM or EE Measures, net of fuel costs and non-fuel variable operating and maintenance expenses avoided at the time of the kilowatt-hour sale(s) lost due to the DSM or EE Measures[1], or in the case of purchased power, in the applicable billing period incurred by DEP public utility operations as the result of a new DSM or EE Measure. PPIs shall not be considered in the calculation of NLR or NLR recovery.

10. *Net-to-gross* (NTG) *factor* means an adjustment factor used to compute the net kW/kWh savings by accounting for behavioral effects, including, but not limited to, free ridership, moral hazard, free drivers, and spillover.

11. *Portfolio Performance Incentive* (PPI) means a utility incentive payment to DEP as a bonus or reward for adopting and implementing new (as defined in N.C. Gen. Stat. § 62-133.9(a)) EE or DSM Measures and/or Programs. The PPI is based on the sharing of avoided cost savings, net of Program Costs, achieved by those DSM and EE Programs in the aggregate. Such Program Costs will be adjusted as discussed elsewhere in this Mechanism. The PPI is also subject to certain limitations as further set forth in this Mechanism. PPI excludes NLR.

12. *Program Return Incentive (PRI)* means a utility incentive payment to DEP for adopting and implementing programs that fail to pass the Utility Cost Test, but are approved by the Commission due to the societal benefit they provide, such as low income programs. For these types of programs, the PRI will be based on a percentage of the NPV of the avoided costs savings achieved by those DSM and EE Programs. The PRI is subject to certain additional factors and limitations, as further set forth in this Mechanism.

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[1] Avoided fuel costs would technically be measured at the marginal cost of fuel avoided at the time of the lost kWh sale. However, because fuel costs themselves are subject to true-up, it is administratively easier and results in the same overall revenue requirement outcome to measure fuel costs associated with NLR at the then-current approved prospective fuel and fuel-related cost factor.

13. *Program* means one or more new DSM or EE Measures with similar objectives that have been consolidated for purposes of delivery, administration, and cost recovery, and that have been adopted on or after January 1, 2007, including subsequent changes and modifications.

14. *Program Costs* are costs that are directly attributable or reasonably and appropriately allocable to specific DSM or EE Programs or groups of Programs (for purposes of setting the DSM/EE and DSM/EE EMF riders), and include all appropriate and reasonable Incremental Program Costs, and reasonably assigned or allocated administrative and general expenses and other Common Costs, net of any reasonably assigned or allocated grants, tax credits, Program Cost adjustments as discussed elsewhere in this Mechanism, or other reductions in cost received by the utility from outside parties.

15. *Total Resource Cost* (TRC) *test* means a cost-effectiveness test that measures the net costs of a DSM or EE Program or portfolio as a resource option based on the incremental costs of the Program or portfolio, including both the participants' costs and the utility's costs (excluding incentives paid by the utility to or on behalf of participants). The benefits for the TRC test are the avoided supply costs (i.e., the reduction in generation capacity costs, transmission and distribution capacity costs, and energy costs caused by a load reduction), valued at marginal cost for the periods when there is a load reduction. The avoided supply costs shall be calculated using net Program or portfolio savings (i.e., savings net of reductions in energy

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use (NTG impacts) that would have happened even in the absence of the Program). Non-Energy benefits as approved for use by the Commission may be considered in the determination of TRC results. The costs for the TRC test are the incremental net Program or portfolio costs incurred by the utility and participants, plus the increased supply costs for any periods in which load is increased. All costs of equipment, installation, operation and maintenance (O&M), removal (less salvage value), and administration, no matter who pays for them, are included in this test. However, Common Costs shall not be included in a Program-level TRC test used for program approval purposes, but shall be included in a portfolio-level TRC test. Any grants, tax credits, or other reductions in cost received by the utility or participants from outside parties and specifically related to the Program or portfolio, as applicable, are considered a reduction to costs in this test.

16. *Utility Cost Test* (UCT) means a cost-effectiveness test that measures the net costs of a DSM or EE Program or portfolio as a resource option based on the incremental costs incurred by the utility (including incentive costs paid by the utility to or on behalf of participants) and excluding any net costs incurred by the participants. The

benefits for the UCT are the avoided supply costs (i.e., the reduction in generation capacity costs, transmission and distribution capacity costs, and energy costs caused by a load reduction), valued at marginal cost for the periods when there is a load reduction. The avoided supply costs shall be calculated using net Program or portfolio savings (i.e., savings net of reductions in energy use (NTG impacts) that would have happened even in the absence of the Program or portfolio). The costs for the UCT are the net Program or portfolio Costs incurred by the utility and the increased supply costs for any period in which load is increased. Utility costs include initial and annual costs, such as the cost of utility equipment, O&M, installation, Program or portfolio administration, incentives paid to or on behalf of participants, and participant dropout and removal of equipment (less salvage value). However, Common Costs shall not be included in a Program-level UCT test used for program approval purposes, but shall be included in a portfolio-level UCT test. Any grants, tax credits, or other reductions in cost received by the utility from outside parties and specifically related to the Program are considered a reduction to costs in this test.

17. *Vintage Year* means an identified 12-month period in which a specific DSM or EE Measure is installed for an individual participant or group of participants.

Application for Approval of Programs

18. In evaluating potential DSM/EE Measures and Programs for selection and implementation, DEP will first perform a qualitative measure screening to ensure Measures are:

(a) Commercially available and sufficiently mature;

(b) Applicable to the DEP service area demographics and climate; and

(c) Feasible for a utility DSM/EE Program.

19. DEP will then further screen EE and DSM Measures for cost-effectiveness. For purposes of this screening, estimated incremental EM&V costs attributable to the Measures shall be included in the Measures' costs. With the exception of Measures included in a Low-Income Program, or other Program in which PPI incentives are not requested that may potentially be filed with the Commission for approval, an EE or DSM Measure with a UCT result less than 1.0 will not be considered further, unless the Measure can be bundled into an EE or DSM Program to enhance the overall cost- effectiveness of that Program. Measures under consideration for bundling, whether as part of a new Program or into an existing Program, should,

unless otherwise approved by the Commission, be consistent with and related to the measure technologies, and/or delivery channels currently offered in the existing Program or to be otherwise offered in the new Program. Consistent with DEP's agreement with Piedmont Natural Gas and Public Service Company of NC, with the exception of Low- Income Programs, all EE and DSM Measures associated with an end-use that can be served by natural gas must pass the UCT.

20. With the exception of Low-Income Programs or other programs explicitly identified at the time of the application for their approval, all Programs submitted for approval will have a Program-level UCT result greater than 1.00. Additionally, for purposes of calculating cost-effectiveness for program approval, consistent with the Commission's Orders in Docket Nos. E-2, Sub 1145 and E-2, Sub 1174, the Company shall use projected avoided capacity and energy benefits specifically calculated for the program, as derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as of the date of the filing for the new program approval. However, for the calculation of the underlying avoided energy credits to be used to derive the program-specific avoided energy benefits, the calculation will be based on the projected EE portfolio hourly shape, rather than the assumed 24x7 100 MW reduction typically used to represent a qualifying facility. For purposes of determining cost-effectiveness, estimated incremental EM&V costs attributable to each Program shall be included in the Program costs. DEP will comply, however, with Commission Rule R8- 60(i)(6)(iii), which requires DEP to include in its biennial Integrated Resource Plan, revised as applicable in its annual report, certain

information regarding the Measures and Programs that it evaluated but rejected.

21. If a Program fails the economic screening in Paragraph 19 above, DEP will determine if certain Measures can be removed from the Program to satisfy the criteria established in Paragraph 19.

22. DEP will provide its Stakeholder Collaborative with information relating to Programs and Measures either currently being considered or planned for future consideration. DEP will also seek suggestions from its Collaborative for additional Programs and Measures for its future consideration.

23. Nothing in this Mechanism relieves DEP from its obligation to comply with Commission Rule R8-68 when filing for approval of DSM or EE Measures or Programs. As specifically required by Commission Rule R8-68(c)(3)(iii), DEP shall, in its filings for approval of Measures and Programs, describe the

industry-accepted methods to be used to collect and analyze data; measure and analyze Program participation; and evaluate, measure, verify, and validate the energy and peak demand savings. In its filings, DEP shall also provide a schedule for reporting the results of this EM&V process to the Commission. The EM&V process description should describe not only the methodologies used to produce the impact estimates utilized, but also any methodologies the Company considered and rejected. Additionally, where known, DEP shall identify the independent third party it plans to use for purposes of EM&V, and include an estimate of all third-party costs in its filing. If not known at the time of filing for approval, the information shall be provided at the time of DEP's next annual rider filing.

Program Management

24. In each annual DSM/EE cost recovery filing, DEP shall (a) perform prospective cost-effectiveness test evaluations for each of its approved DSM and EE Programs, (b) perform prospective aggregated portfolio-level cost-effectiveness test evaluations for its approved DSM/EE Programs (including any assigned or allocated administrative and general or other common costs), and (c) include these prospective cost-effectiveness test results in its DSM/EE rider application.

24A. Consistent with the Commission's Orders in Docket Nos. E-2, Sub 1145 and E-2, Sub 1174, for purposes of calculating prospective cost-effectiveness in each DSM/EE rider proceeding to be used to determine whether a program should remain in the portfolio, the Company shall assess each program by:

(a) Using projected avoided capacity and energy benefits specifically calculated for each program, as derived from the underlying resource plan, production cost model, and cost inputs that generated the

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avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as of December 31 of the year immediately preceding the date of the annual DSM/EE rider filing. However, for the calculation of the underlying avoided energy credits to be used to derive the program-specific avoided energy benefits, the calculation will be based on the projected EE portfolio hourly shape, rather than the assumed 24x7 100 MW reduction typically used to represent a qualifying facility; and,

(b) Evaluating each cost-effectiveness test using projections of participation, savings, costs, and benefits for the upcoming vintage year.

24B. The parties acknowledge that prospective cost-effectiveness evaluations are snapshots of the program's performance, and that ongoing cost- effectiveness is impacted by many factors outside the Company's control, including but not limited to market and economic conditions, avoided costs, and government mandates. The parties shall continue to work to maintain the cost-effectiveness of its portfolio and individual programs. However, for any program that initially demonstrates a UCT, determined pursuant to Paragraph 24A above of less than 1.00, the Company shall include a discussion in its annual DSM/EE rider proceeding of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program.

24C. For programs that demonstrate a prospective UCT, determined pursuant to Paragraph 24A above, of less than 1.00 in a second DSM/EE rider proceeding, the Company shall include a discussion of what actions it has taken to improve cost-effectiveness. Fluctuations of UCT above and below 1.0 should be addressed on a case by case basis.

24D. For programs that demonstrate a prospective UCT, determined pursuant to Paragraph 24A above, of less than 1.00 in a third DSM/EE rider proceeding, the Company shall terminate the program effective at the end of the year following the DSM/EE rider order, unless otherwise ordered by the Commission. However, any party may propose termination of a program prior to a third DSM/EE rider proceeding if earlier information indicates that cost-effectiveness is not likely to reach 1.0 or greater under the UCT test.

25. DEP will seek to leverage available state and federal funds to operate effective efficiency Programs. Its application for such funds will be transparent with respect to the cost, operation, and profitability of Programs operated with those funds in a manner consistent with its authorized revenue recovery mechanism. Use of such funds helps offset the

participant's project costs and is supplemental to DEP's incentives to participants. As such, these funds will not change the impacts or Program- or portfolio-level cost-effectiveness of DEP's Programs as calculated using the UCT. Further, the amount of avoided costs recognized by the Company will not be reduced if participants also use state or federal funds to offset any portion of their project costs.

Program Modifications

25A. Modifications to Commission approved DSM/EE Programs will be considered as provided for in Attachment A to this Mechanism.

25B. Modifications filed with the Commission for approval will be evaluated under the same guidelines and parameters used in DEP's most recently filed DSM/EE rider proceeding.

Stakeholder Collaborative

26. DEP will conduct periodic collaborative stakeholder meetings for the purpose of collaborating on new Program ideas, reviewing modifications to existing Programs, ensuring an accurate public understanding of the Programs and funding, reviewing the EM&V process, giving periodic status reports on Program performance, helping to set EM&V priorities, providing recommendations toward DEP's submission of applications to revise or extend Programs and rate structures, and guiding efforts to expand cost- effective Programs for low-income customers. A third party may facilitate the discussions

27. The Carolinas EE Collaborative is an advisory group made up of interested stakeholders from across North and South Carolina representing a wide array of customer groups and interests related to energy efficiency and demand response. The Collaborative should serve as an open forum for the sharing of information and discussion of topics related to energy efficiency including program design and development, program evaluation, regulatory and other market conditions that will impact program performance, specific issues or topics as requested by the North and South Carolina Utilities Commissions in orders regarding DSM and EE matters, and other topics or issues to achieve the most demand and energy savings possible. A third party may facilitate the discussions. The collaborative will continue to determine its own rules of operation, including the process for setting the agendas and activities of the group, consistent with these terms. Members agree to participate in the advisory group in good faith consistent with mutually-agreed upon rules of participation. Meetings are open to additional parties who agree to the participation rules.

28. DEP will provide information related to the development of EE and DSM to stakeholders in a transparent manner. The Company agrees to disclose Program-related data at a level of detail similar to that which it has disclosed in other states or as disclosed by other regulated utilities in the Carolinas. The Company will share all aspects of the development and evaluation of Programs, including the EM&V process.

29. At its discretion, the Company may require confidentiality agreements with members who wish to review confidential data or any calculations that could be used to determine the data. Disclosure of this data would harm DEP competitively and could result in financial harm to its customers. Participation in the advisory group shall not preclude any party from participating in any Commission proceedings.

Distribution System Demand Response (DSDR) Program

30. The DSDR Program is an EE Program defined as "new" pursuant to N.C. Gen. Stat. § 62-133.8 and N.C. Gen. Stat. § 62-133.9, and is eligible for recovery of reasonable and prudent costs, as well as NLR, subject to the terms and conditions of NLR set forth herein. The DSDR Program is not eligible for recovery of a PPI.

31. The rate of return on investment used to determine the DSDR Program capital-related costs included in each annual rider will be based on the then- current capital structure, embedded cost of preferred stock, and embedded cost of debt of the Company (net of appropriate income taxes), and the cost of common equity approved in the Company's then most recent general rate case.

Evaluation, Measurement and Verification

32. The EM&V of Programs will be conducted using a nationally recognized protocol to ensure that Programs remain cost-effective. Except for DEP's DSDR Program, EM&V of Programs will be conducted by an independent third-party. EM&V of the DSDR Program will be conducted by DEP. EM&V protocol may be modified with approval of the Commission to reflect the evolution of best practices.

33. EM&V will be applied in accordance with the provisions of Attachment B to this Mechanism.

34. EM&V will also include updates of any NTG factors related to previous NTG estimates for Programs and Measures. All of the updated information will be used in evaluating the continued cost-effectiveness of existing Programs and portfolio. Updates to NTG estimates will be applied consistent with the application of EM&V results pursuant to Attachment B to this Mechanism,

but updates to NTG estimates will not be applied retrospectively to Measures that have already been installed or Programs that have already been completed. If it becomes apparent during the implementation of a Program that NTG factors are substantially different than anticipated, the Company will file appropriate Program adjustments with the Commission.

Opt-Out Eligibility Requirement for Industrial Customers and Certain Commercial Customers

35. Commercial customers with annual consumption of 1,000,000 kWh or greater in the billing months of the prior calendar year and all industrial customers that implement or will implement alternative DSM/EE Measures may, consistent with Commission Rule R8-69(d), elect to not participate in any utility-offered DSM/EE Measures and, after written notification to the utility, will not be subject to the DSM/EE rider and DSM/EE EMF rider. For purposes of application of this option, a customer is defined to be a metered account billed under a single application of a Company rate tariff. For commercial accounts, once one account meets the opt-out eligibility requirement, all other accounts billed to the same entity with lesser annual usage located on the same or contiguous properties are also eligible to opt-out of the DSM/EE rider and DSM/EE EMF rider. Since these rates are included in the rate tariff charges, customers electing this option shall receive a DSM and/or EE credit on their monthly bill statement.

36. Opt-out eligible customers that have received DSM/EE Program incentives will be subject to the applicable DSM/EE rider and DSM/EE EMF rider billings for a period of no less than 36 months.

37. Eligible non-residential customers may opt out of either or both of the DSM and EE categories of Programs as well as opt back into either or both. If a customer receives Program incentives from a Company DSM or EE Program, that customer must opt-in for a period of no less than 36 months. A customer receiving Program incentives from a DSM Program will be required to pay the DSM portion of the DSM/EE Rider for a period of not less than 36 months. A customer receiving Program incentives from an EE Program will be required to pay the EE portion of the DSM/EE Rider for a period of not less than 36 months.

38. In cases when the DSM rate element of Rider DSM/EE is a credit, any opt- out eligible customer who wishes to opt-in to the DSM portion of the Rider, without participating in a DSM program, will be required to remain opted into the DSM portion of the Rider for the same number of months that they received a bill credit following the last month in which they received a DSM bill credit from the Rider.

39. In cases when the EE rate element of Rider DSM/EE is a credit, any opt- out eligible customer who wishes to opt-in to the EE portion of the Rider, without participating in a EE program, will be required to remain opted into the EE portion of the Rider for the same number of months that they received a bill credit following the last month in which they received a EE bill credit from the Rider.

Procedural Matters and General Structure of Riders

40. The rate period for each proposed DSM/EE Rider will be the next upcoming calendar year at the time of the filing of DEP's annual DSM/EE rider application. The test period used in the development of the DSM/EE EMF Rider will be the most recently concluded calendar year at the time of filing of the application.

41. For purposes of measuring the cost-effectiveness of Programs and for calculation of the PPI and PRI, a Vintage Year will be equivalent to a calendar year.

42. The annual filing date of DEP's DSM/EE rider application, supporting testimony, and exhibits will be no later than 98 days prior to the hearing date prescribed by Commission Rule (currently the first Tuesday of June of each calendar year). Should the Company become aware prior to filing of a determined or possible change in the hearing date, the Company shall strive to file its application and associated documents no later than 98 days prior to the changed hearing date.

43. DEP shall not request that the annual hearing to consider the proposed DSM/EE and DSM/EE EMF riders be held sooner than 98 days after the filing date of the Company's application, supporting testimony, and Exhibits.

44. All DSM/EE and DSM/EE EMF riders shall be calculated and charged to customers based on the annual revenue requirements associated with DSM and EE Programs. Separate DSM/EE and DSM/EE EMF riders shall be calculated for the Residential customer class, the Non-Residential customer classes, and the Lighting class.

45. One integrated (prospective) DSM/EE rider and one integrated DSM/EE EMF rider shall be calculated for the Residential class and the Residential portion of the Lighting class, respectively, to be effective each rate period. The integrated Residential and Lighting class DSM/EE EMF riders shall include all true-ups for each Vintage Year appropriately considered in each proceeding.

46. Separate DSM and EE billing factors will be available to Non-Residential opt-out-eligible customers. Additionally, the Non-Residential DSM and EE

rates and the DSM and EE EMF billing factors will be appropriately considered in each proceeding, so that the factors can be appropriately charged to Non-Residential opt-out eligible customers.

47. For purposes of normalizing or forecasting kWh sales for its annual DSM/EE and DSM/EE EMF rider filing, DEP shall calculate customer growth, weather normalization, and other applicable adjustments on the basis of the test period and/or rate period for each annual filing, as applicable.

Allocation Methodologies

48. Unless the Commission determines otherwise in a N.C. Gen. Stat. § 62-133.9 DSM/EE rider (or other) proceeding:

(a) The Program Costs of an approved DSM or EE Program will be allocated to the North Carolina and South Carolina retail jurisdictions and will only be recovered from those customer classes to which the Program is targeted.

(b) No Program Costs of any approved DSM or EE Program will be allocated to the wholesale jurisdiction.

(c) For EE Programs, the costs of each Program will be allocated based on the annual energy requirements of North Carolina and South Carolina retail customers (at the generator), as reflected in the annual cost of service studies.

(d) For DSM Programs, the aggregated costs of DSM Programs will be allocated based on the annual summer coincident peak demand of North Carolina and South Carolina retail customers, as reflected in the annual cost of service studies.

(e) The allocation factors and inputs used to allocate the estimated rate period costs of DSM and EE Programs shall be those drawn from the most recently filed cost of service study at the time the annual cost recovery filing is made. The allocations of costs shall be trued up at the time that finalized and trued-up costs for a given test period are initially passed through the DSM/EE EMF, using the most recently filed cost of service study at the time the filing is made (but for no later year than the period being trued up). For subsequent true-ups of that period, the cost of service study used will be the same as that used for the initial true-up.

(f) For purposes of recovery through the DSM/EE and DSM/EE EMF riders, the Company's North Carolina retail jurisdictional costs for approved DSM and EE Programs and Measures shall be assigned

or allocated to North Carolina retail customer classes by directly assigning the North Carolina retail jurisdictional costs to the customer group to which the Program is offered. For the DSDR Program, North Carolina retail jurisdictional amounts shall be allocated to customer classes on the basis of the energy requirements of each class, drawn from the most recently filed cost of service study at the time the annual cost recovery filing is made (adjusted to exclude the energy requirements of opted-out customers). The process of estimating and truing up the class assignments and allocations will be the same as practiced for jurisdictional allocations.

Cost Recovery

49. In general, as provided in Commission Rule R8-69 and N.C. Gen. Stat. § 62-133.9(d), but subject to the specific provisions and/or modifications contained elsewhere in this Mechanism, DEP shall be allowed to recover, through the DSM/EE rider, all reasonable and prudent Program Costs reasonably and appropriately estimated to be incurred in expenses, during the current rate period, for DSM and EE Programs that have been approved by the Commission under Rule R8-68. As permitted by N.C. Gen. Stat. § 62-133.9(d), but subject to the specific provisions and/or modifications contained elsewhere in this Mechanism, any of the Stipulating Parties may propose a procedure for the deferral and amortization in future DSM/EE riders of all or a portion of DEP's reasonable and prudent O&M Program Costs to the extent those costs are intended to produce future benefits.

50. Unless the Commission determines otherwise, and subject to the specific provisions and/or modifications contained elsewhere in this Mechanism, DEP shall be allowed to amortize any O&M costs incurred through Vintage Year 2020 deferred pursuant to Paragraph 49 of this Mechanism over a period of time not to exceed 10 years..

51. Beginning with Vintage (calendar) Year 2016, and extending through Vintage Year 2020 (as reflected in its 2019 Rider filing), DEP may recover, subject to approval by the Commission in the annual DSM/EE rider proceedings, Program Costs incurred, without deferral for amortization in future DSM/EE riders, even if Program Costs incurred for the same Program in prior years have been deferred and amortized.

52. With regard to O&M Program Costs incurred prior to January 1, 2016, said costs will be recovered using the amortization rates existing at December 31, 2015, until such time that those deferred costs are recovered, in their entirety, through the DSM/EE cost recovery clause, unless the Parties recommend, and the Commission approves, a different treatment.

53. O&M Program Costs incurred in Vintage Year 2021 will be recovered utilizing the same amortization periods as utilized for Vintage Year 2020 Costs for the same Program, unless otherwise approved by the Commission.

54. Beginning with Vintage Year 2022, unless otherwise ordered by the Commission pursuant to its own motion or at the request of another party, and extending through a Vintage Year as identified in a future Mechanism review, DEP may recover all Program Costs previously recovered through amortization periods exceeding three years over amortization periods of no less than three years.

55. With regard to O&M Program Costs incurred on and subsequent to January 1, 2016 but prior to January 1, 2022, said costs will be recovered using the amortization rates existing at December 31, 2021, until such time that those deferred costs are recovered, in their entirety, through the DSM/EE cost recovery clause, unless the Parties recommend, and the Commission approves, a different treatment.

56. In the next Mechanism review, the parties shall consider whether or not to allow the minimum three-year amortization period designated in Paragraph 54 above to be further reduced, taking into consideration the impact upon customer rates, as well as other relevant factors.

57. Pursuant to Commission Rule R8-69(b)(6), except for administrative and general expenses (addressed in Paragraph No. 58 below), DEP shall be allowed to earn a rate of return at the overall weighted average net-of-tax rate of return approved in DEP's most recent general rate case on all such unamortized deferred costs (net of income taxes). The return so calculated will be adjusted in any rider calculation to reflect necessary recoveries of income taxes. Pursuant to Commission Rule R8-69(c)(3), the Company is not allowed to accrue a return on NLR or the PPI.

58. To the extent DEP chooses to defer and amortize in future DSM/EE riders the Program Costs for a Program pursuant to Paragraph No. 54 above, non-incremental administrative and general costs reasonably assigned or allocated to, but not directly related to, that Program will be deferred and amortized over a period not to exceed three years, unless the Commission determines otherwise. Pursuant to

Commission Rule R8-69(b)(6), DEP shall be allowed to earn a rate of return at the overall weighted average net- of-tax rate of return approved in DEP's most recent general rate case on all such unamortized deferred administrative and general costs (net of income taxes). The return so calculated will be adjusted in any rider calculation to reflect necessary recoveries of income taxes. However, irrespective of the prospective treatment of Program Costs in calendar year 2016 or afterwards, previously deferred administrative and general costs will be

recovered using existing amortization rates, until such time that those deferred costs are recovered, in their entirety, through the DSM/EE cost recovery clause, unless the parties recommend, and the Commission approves, a different treatment.

59. The DSM/EE EMF rider shall reflect the difference between the reasonable and prudent Program Costs incurred or amortized during the applicable test period (Vintage Year) and the revenues actually realized during such test period under the DSM/EE rider then in effect.

60. For Program Costs not deferred for amortization in future DSM/EE riders, the accrual of a return on any under-recoveries or over-recoveries of cost will follow the requirements of Commission Rule R8-69(b), subparagraphs (3) and (6), unless the Commission determines otherwise.

61. The cost and expense information filed by DEP pursuant to Commission Rules R8-68(c) and R8-69(f) shall be categorized by Measurement Unit or Program, as applicable, and period, consistent with the presentation included in the Company's application.

Net Lost Revenues (NLR)

62. When authorized pursuant to Commission Rule R8-69(c) and unless the Commission determines otherwise, DEP shall be permitted to recover, through the DSM/EE and DSM/EE EMF riders, NLR associated with the implementation of approved DSM and EE Measurement Units or Programs, subject to the restrictions set out below.

63. The North Carolina retail kWh sales reductions that result from an approved measurement unit installed in a given Vintage Year shall be eligible for use in calculating NLR eligible for recovery only for the first 36 months after the installation of the Measurement Unit. Thereafter, such kWh sales reductions will not be eligible for calculating recoverable NLR for that or any other Vintage Year.

64. Programs or Measures with the primary purpose of promoting general awareness and education of EE and DSM activities, as well as research and development activities, are ineligible for the recovery of NLR.

65. In order to recover estimated NLR associated with a Pilot Program or Measure, DEP must, in its application for program or measure approval, demonstrate (a) that the program or measure is of a type that is intended to be developed into a full-scale, Commission-approved program or measure, and (b) that it will implement an EM&V plan based on industry-accepted protocols for the program or measure. No pilot program or measure will be eligible for NLR recovery upon true-up unless it (a) is ultimately proven to

have been cost-effective, and (b) is developed into a full-scale, commercialized program.

66. Notwithstanding the allowance of 36 months' NLR associated with eligible kWh sales reductions, the kWh sales reductions that result from measurement units installed shall cease being eligible for use in calculating NLR as of the effective date of (a) a Commission-approved alternative recovery mechanism that accounts for the eligible NLR associated with eligible kWh sales reductions, or (b) the implementation of new rates approved by the Commission in a general rate case or comparable proceeding to the extent the rates set in the general rate case or comparable proceeding are set to explicitly or implicitly recover the NLR associated with those kWh sales reductions.

67. Recoverable NLR shall be calculated in a manner that appropriately reflects the incremental revenue losses suffered by the Company, net of avoided fuel and non-fuel variable O&M expenses.

68. Overall recoverable NLR as measured for the 36-month period identified in Paragraph 63 above shall be reduced by any increases in Net Found Revenues during the same periods (offset by any negative found revenues found appropriate and reasonable by the Commission pursuant to the provisions of paragraph 8 of this Mechanism and other factors deemed applicable by the Commission). The "decision tree" adopted by Order in Docket No. E-2, Sub 931, on January 20, 2015, should be applied for determining what constitutes Net Found Revenues. DEP shall closely monitor its utility activities to determine if they are causing a customer to increase demand or consumption, and shall identify and track all such activities with the aid of the "decision tree," so that they may be evaluated by intervening parties and the Commission as potential Net Found Revenues. Net Found Revenues

shall be calculated in an appropriate and reasonable manner that mirrors the calculation used to determine NLR.

69. Recoverable NLR shall ultimately be based on kWh sales reductions and kW savings verified by the EM&V process and approved by the Commission. Recoverable NLR shall be estimated and trued-up, on a Vintage Year basis, in the following manner:

(a) As part of the DSM/EE rider approved in each annual cost and incentive recovery proceeding, DEP shall be allowed to recover the appropriate and reasonable level of recoverable NLR associated with each applicable program and Vintage Year (subject to the limitations set forth in this Mechanism), estimated to be experienced during the rate period for which the DSM/EE rider is being set.

(b) NLR related to any given program/measure and Vintage Year shall be trued-up through the DSM/EE EMF rider in subsequent annual cost and incentive recovery proceedings based on the Commission- approved results of the appropriate EM&V studies related to the program/measure and Vintage Year. The true-up shall be based on verified savings and shall be applied to prospective and past time periods in accordance with the Evaluation, Measurement, and Verification section of this Mechanism.

(c) The true-up shall be calculated based on the difference between projected and actual recoverable NLR for each Program and period under consideration, accounting for any differences derived from the completed and reviewed EM&V studies, including: (1) the projected and actual number of installations per Measurement Unit; (2) the projected and actual net kilowatt-hour (kWh) and kilowatt (kW) savings per installation; (3) the projected and actual gross lost revenues per kWh and kW saved; and (4) the projected and actual deductions from gross lost revenues per kWh and kW saved.

(d) The reduction in NLR due to Net Found Revenues (offset by any approved and applicable negative found revenues) shall be trued up in a manner consistent with the true-up of NLR.

(e) The combined total of all Vintage Year true-ups calculated in a given year's Commission Rule R8-69 proceeding shall be incorporated into the appropriate DSM/EE EMF billing factor.

Portfolio Performance Incentive (PPI) and Program Return Incentive (PRI)

70. When authorized pursuant to Commission Rule R8-69(c), DEP shall be allowed to collect a PPI and PRI, as each is applicable, for its DSM/EE portfolio for each Vintage Year, separable into Residential, Lighting, Non- Residential DSM, Non-Residential EE categories. The PPI and PRI, as applicable, shall be subject to the restrictions set out below.

71. Programs, Measures, and activities undertaken by DEP with the primary purpose of promoting general awareness of and education about EE and DSM activities, as well as research and development activities, that are not directly associated with a Commission approved EE or DSM Program, are ineligible to be included in the portfolio for purposes of the PPI or PRI calculations.

72. Unless (a) the Commission approves DEP's specific request that a pilot program or measure be eligible for PPI or PRI inclusion when DEP seeks approval of that program or measure, and (b) the pilot is ultimately commercialized, pilot programs or measures are ineligible for and the

benefits and costs associated with those pilots will not be factored into the calculation of the PPI.

73. The PPI and PRI for each Vintage Year shall be incorporated into DEP's DSM/EE or DSM/EE EMF billing factors, as appropriate.

74. In its annual filing, pursuant to Commission Rule R8-69(f), DEP shall file an exhibit that indicates, for each Program or Measure for which it seeks a PPI or PRI, the annual projected and actual utility costs, participant costs, number of Measurement Units installed, per kW and kWh impacts for each Measurement Unit, and per kW and kWh avoided costs for each Measurement Unit, consistent with the UCT, related to the applicable Vintage Year installations that it requests the Commission to approve. Upon its review, the Commission will make findings based on DEP's annual filing for each Program or Measure that is included in an estimated or trued-up PPI or PRI calculation for any given Vintage Year.

75. Low-Income Programs and other specified societal programs or other programs explicitly approved with expected UCT results less than 1.00 shall not be included in the portfolio for purposes of the PPI calculation until they demonstrate UCT results greater than 1.00. However, such programs will be eligible for the PRI, if so approved by the Commission, until they demonstrate UCT results greater than 1.00.

76. The PPI shall be based on the net dollar savings of DEP's DSM/EE portfolio, as calculated using the UCT. The North Carolina retail jurisdictional and class portions of the system-basis net dollar savings shall be determined in the same manner as utilized to determine the North Carolina retail jurisdictional and class portions of recoverable system costs.

77. Unless the Commission determines otherwise in an annual N.C. Gen. Stat. § 62-133.9 DSM/EE rider proceeding, and subject to the factors and limitations set forth elsewhere in this Mechanism, beginning for Vintage Year 2022 the amount of the pre-income-tax PPI initially to be recovered for the entire DSM/EE portfolio for a Vintage Year, excluding Programs not eligible for a PPI, shall be equal to 10.60% multiplied by the present value of the estimated net dollar savings associated with the DSM/EE portfolio installed in that Vintage Year, calculated by Program using the UCT (and excluding Low Income Programs and other specified societal programs). The present value of the estimated net dollar savings shall be the difference between the present value of the annual lifetime avoided cost savings for measurement units projected to be installed in that Vintage Year and the present value of the annual lifetime program costs for those measurement units. The annual lifetime avoided cost savings for measurement units installed in the applicable Vintage Year shall be calculated by multiplying the number of each specific type of Measurement Unit projected to be

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installed in that Vintage Year by the most current estimates of each lifetime year's per installation kW and kWh savings and by the most current estimates of each lifetime year's per kW and kWh avoided costs. In calculating the forecasted initial PPI it will be assumed that projections will be achieved.

78. Beginning with Vintage Year 2022, the dollar amount of the pre-tax PPI ultimately allowed for each Vintage Year, after true-up pursuant to Paragraph 89 of this Mechanism, shall be no greater than the dollar amount that produces a 19.50% margin over the aggregate pre-tax Program Costs for the Vintage Year of those programs in the Portfolio that are eligible for the PPI. Likewise, the dollar amount of the pre-tax PPI ultimately allowed for each Vintage Year, after true-up pursuant to Paragraph 89 of this Mechanism, shall be no less than the dollar amount that produces the following margins over the aggregate pre-tax Program Costs for the Vintage Year of those programs in the Portfolio that are eligible for the PPI.

Vintage Year 2022:	10.00%
Vintage Year 2023:	6.00%
Vintage Year 2024:	2.50%
Vintage Year 2025 and afterwards, until the next Mechanism review is completed:	2.50%

When making its initial estimates of the PPI pursuant to this Mechanism, DEP shall utilize the best and most accurate estimate of the margin and the resulting PPI percentage it can determine at that time.

79. Unless the Commission determines otherwise in a N.C. Gen. Stat. § 62-133.9 DSM/EE rider proceeding, the PPI for vintage periods subsequent to the approval of this mechanism through Vintage Year 2021 shall be converted into a stream of no more than 10 levelized annual payments, accounting for and incorporating DEP's overall weighted average net-of-tax rate of return approved in DEP's most recent general rate case as the appropriate discount rate. After Vintage Year 2021, the PPI related to any given Vintage Year will be levelized over the same period over which O&M Program Costs for that Vintage Year are amortized. Levelized annual payments applicable to Programs in prior vintage periods will continue until all such amounts are recovered.

80. The PRI shall be based on the gross avoided costs of those programs eligible for the PRI. The North Carolina retail jurisdictional and class portions

of the system-basis gross dollar savings shall be determined in the same manner as utilized to determine the North Carolina retail jurisdictional and class portions of recoverable system costs.

81. Unless the Commission determines otherwise in an annual N.C. Gen. Stat. § 62-133.9 DSM/EE rider proceeding, and subject to the factors and limitations set forth in this Mechanism, beginning for Vintage Year 2022 the amount of the pre-income-tax PRI initially to be recovered for Low Income Programs and other specified societal programs not eligible for a PPI shall be a percentage, as determined pursuant to Paragraph 82 of this Mechanism, multiplied by the present value of the estimated gross dollar avoided cost savings associated with the applicable DSM/EE Programs installed in that Vintage Year, used in

determination of the UCT. The present value of the estimated gross dollar savings shall be determined in the same manner as used for Programs eligible for the PPI.

82. The percentage used to determine the estimated PRI for each Vintage Year shall be 10.60%. This percentage will be multiplied by the Vintage Year avoided costs projected to be generated by each approved PRI-eligible program. When making its initial estimates of the PRI, DEP shall utilize the best and most accurate estimate of the UCT and the resulting PRI percentage it can determine at that time.

83. For the PPI and PRI for Vintage Years 2019 and afterwards, consistent with the Commission's Orders in Docket Nos. E-2, Sub 1145 and E-2, Sub 1174, the program-specific per kW avoided capacity benefits and per kWh avoided energy benefits used for the initial estimate of the PPI and PRI and any PPI or PRI true-up will be derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent Commission- approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as of December 31 of the year immediately preceding the date of the annual DSM/EE rider filing. However, for the calculation of the underlying avoided energy credits to be used to derive the program-specific avoided energy benefits, the calculation will be based on the projected EE portfolio hourly shape, rather than the assumed 24x7 100 MW reduction typically used to represent a qualifying facility.

84. No later than December 31, 2021, DEP and the Public Staff will jointly review the issue of the appropriate avoided T&D costs to be used in the Company's calculations of cost-effectiveness and achieved net dollar savings, and, if appropriate, recommend in the Company's annual DSM/EE rider proceeding adjustments to the avoided T&D cost rates.

85. The per kW avoided transmission and avoided distribution (avoided T&D) costs used to calculate net savings for a Vintage Year shall be based on the

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study update at least every three years only if the study update results in a 20% change from the prior study's avoided T&D costs.

86. Unless DEP and the Public Staff agree otherwise, DEP shall not be allowed to update its avoided capacity costs and avoided energy costs after filing its annual cost and incentive recovery application for purposes of determining the DSM/EE and DSM/EE EMF riders in that proceeding.

87. When DEP files for its annual cost recovery under Commission Rule R8-69, it shall comply with the filing requirements of Commission Rule R8- 69(f)(1)(iii),

reporting all measurement and verification data, even if that data is not final, to assist the Commission and the Public Staff in their review and monitoring of the impacts of the DSM and EE Measures.

88. DEP bears the burden of proving all dollar savings and costs included in calculating the PPI and PRI. As provided in Rule R8-68(c)(3)(iii), DEP shall be responsible for the EM&V of energy and peak demand savings consistent with its EM&V plan.

89. The PPI and PRI for each Vintage Year shall ultimately be based on net or gross dollar savings, as applicable, as verified by the EM&V process and approved by the Commission. The PPI and PRI for each Vintage Year shall be trued-up as follows:

(a) As part of the DSM/EE rider approved in each annual cost and incentive recovery proceeding, DEP shall be allowed to recover an appropriately and reasonably estimated PPI and PRI (subject to the limitations set forth in this Mechanism) associated with the Vintage Year covered by the rate period in which the DSM/EE rider is to be in effect.

(b) The PPI and PRI related to any given Vintage Year shall be trued-up through the DSM/EE EMF rider in subsequent annual cost and incentive recovery proceedings based on the Commission-approved results of the appropriate EM&V studies related to the program/measure and Vintage Year, as determined pursuant to the EM&V Agreement. The true-up shall be based on verified savings and shall be applied to prospective and past time periods in accordance with the Evaluation, Measurement, and Verification section of this Mechanism.

(c) The amount of the PPI ultimately to be recovered for a given Vintage Year shall be based on the present value of the actual net dollar savings derived from all Measurement Units installed in that Vintage Year, as associated with each DSM/EE program offered during that year (excluding Low Income Programs and other specified societal

programs), and calculated by DSM/EE program using the UCT. The present value of the actual net dollar savings shall be the difference between the present value of the annual lifetime avoided cost savings for measurement units installed in that Vintage Year and the present value of the annual lifetime program costs for those measurement units. The annual lifetime avoided cost savings for Measurement Units installed in the applicable Vintage Year shall be calculated by multiplying the number of each specific type of Measurement Unit installed in that Vintage Year by each lifetime year's per installation kW and kWh savings (as verified by the appropriate EM&V study pursuant to the EM&V agreement) and by each lifetime year's per kW and kWh avoided costs as determined when calculating the initially estimated PPI for the Vintage Year. The ultimate PPI will also be subject to the additional factors and limitations set forth in this Mechanism. The Stipulating Parties agree to make all reasonable efforts to ensure that all vintages are fully trued-up within 24 months of the vintage program year.

(d) The amount of the PRI ultimately to be recovered for a given Vintage Year shall be based on the present value of the actual gross dollar savings derived from all Measurement Units installed in that Vintage Year, as associated with each DSM/EE program offered during that year that is eligible for the PRI. Furthermore, the percentage used to determine the final PRI for each Vintage Year will be based on the Company's ability to maintain or improve the cost effectiveness of the PRI-eligible programs. The PRI percentage for each PRI-eligible Program will be determined by comparing (1) the projected UCT ratio for the portfolio of PRI-eligible Programs for the Vintage Year at the time of the Company's DSM Rider filing first estimating that projected Vintage Year UCT ratio to (2) the actual UCT ratio achieved for that portfolio of PRI-eligible Programs as that Vintage Year is trued up in future filings. The ratio (UCT actual / UCT estimate) will then be multiplied by 10.60% to determine the PRI percentage that will be applied to the actual avoided costs generated by each approved PRI- eligible program. At no time will the PRI percentage utilized fall below 2.65% or rise above 13.25%. The present value of the estimated gross dollar savings shall be determined in the same manner as used for determining the recovery of the ultimate PPI. The ultimate PRI will also be subject to the additional factors and limitations set forth in this Mechanism. The Stipulating Parties agree to make all reasonable efforts to ensure that all vintages are fully trued-up within 24 months of the vintage program year.

(e) A program's eligibility for a PPI or PRI will be determined at the time of filing the projection for a Vintage Year and will continue to be

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eligible for the same incentive at the time of the Vintage Year true- up.

(f) If a program previously eligible for a PRI becomes cost effective under the UCT, it will no longer be eligible to receive a PRI in the next projected Vintage Year for the program, but will be eligible for the PPI.

90. The combined total of all Vintage Year true-ups of the PPI and PRI calculated in a given year's Rule R8-69 proceeding shall be incorporated into the appropriate DSM/EE EMF billing factor.

91. The PRI will be determined on the basis of the avoided costs employed in the determination of the UCT. PRI amounts will be assigned to the Program in which they were earned.

92. The PPI for each Vintage Year shall be allocated to DSM and EE programs in proportion to the present value net dollar savings of each program for the Vintage Year, as calculated pursuant to the method described herein.

Other Incentives

93. As further incentive to motivate the Company to aggressively pursue savings from cost-effective EE and DSM Programs, if the Company achieves annual energy savings of 1.0% of the prior year's DEP system retail electricity sales, in any year during the four-year 2022-2025 period, the Company will receive an additional incentive of $500,000 for that year. During that same period, if the Company fails to achieve annual energy savings of 0.5% of retail sales, net of sales associated with customers opting out of the Company's EE programs, the Company will reduce its EE revenue requirement by $500,000. Verification of this achievement will be obtained through the EM&V process discussed elsewhere in this Mechanism.

Financial Reporting Requirements

94. In its quarterly ES-1 Reports to the Commission, DEP shall calculate and present its primary North Carolina retail jurisdictional earnings by including all actual EE and DSM Program revenues, including PPI and NLR incentives, and costs. Additionally, DEP shall prepare and present (1) supplementary schedules setting forth the Company's North Carolina retail jurisdictional earnings excluding the effects of the PPI; (2) supplementary schedules setting forth the Company's North Carolina retail jurisdictional earnings excluding the effects of its EE and DSM Programs; (3) supplementary schedules setting forth earnings, including overall rates of return and returns on common equity actually realized from DEP's EE and

DSM Programs in total and stated separately by Program Class (Program Classes are hereby defined to be (a) EE Programs and (b) DSM Programs); and (4) supplementary schedules setting forth earnings, including overall rates of return and returns on common equity actually realized from DEP's DSDR Program and

(b) all other Programs, collectively, in the EE Program Class. (Show DSDR Program returns and all other collective EE Program returns separately.) Detailed workpapers shall be provided for each scenario described above. Such workpapers, at a minimum, shall clearly show actual revenues; expenses; taxes; operating income; rate base/investment, including components; and the applicable capitalization ratios and cost rates, including overall rate of return and return on common equity.

Review of Mechanism

95. The terms and conditions of this Mechanism shall be reviewed by the Commission every four years unless otherwise ordered by the Commission. However, a Stipulating Party may request the Commission to initiate such a review at any time within the four year period. The Company and other parties shall submit any proposed changes to the Commission for approval at the time of the filing of the Company's annual DSM/EE rider filing. During the time of review, the Mechanism shall remain in effect until further order of the Commission revising the terms of the Mechanism or taking such other action as the Commission may deem appropriate.

Term

96. This Mechanism shall continue until terminated pursuant to Order of the Commission.

No Precedential Effect

97. The terms of this Mechanism, including the methods and results of determining the PPI, PRI, and other Bonus Incentives, shall not be considered precedential for any purpose other than their application to eligible DSM/EE Programs and cost and utility incentive recovery associated with those Programs, and only until those terms are next partially or wholly reviewed.

ELECTRIC – ADJUSTMENTS OF RATES/CHARGES

DOCKET NO. E-2, SUB 1250

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	
Pursuant to N.C. Gen. Stat. § 62-133.2 and NCUC	)	ORDER APPROVING FUEL
Rule R8-55 Relating to Fuel and Fuel-Related	)	CHARGE ADJUSTMENT
Charge Adjustments for Electric Utilities	)	
	)	

HEARD: Tuesday, September 15, 2020 at 10:00 a.m. in the Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina (Public Witness Hearing, Hearing Examiner Heather Fennell, Presiding)

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

APPEARANCES:

For Duke Energy Progress, LLC:

Kendrick Fentress, Asociate General Counsel, Duke Energy Corporation, NCRH 20/Post Office Box 1551, Raleigh, North Carolina 27602-1551

Robert Kaylor, Law Office of Robert Kaylor, 353 Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For Carolina Utility Customers Association, Inc.:

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

For Carolina Industrial Group for Fair Utility Rates II:

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

For North Carolina Sustainable Energy Association:

Ben Smith, Regulatory Counsel, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the Sierra Club:

Gudren Thompson, Southern Environmeal Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For the Using and Consuming Public:

John D. Little, Staff Attorney, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On June 9, 2020, 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, exhibits, and workpapers of Dana M. Harrington, and the testimony and exhibits of Regis Repko, Kenneth D. Church, Kelvin Henderson and Brett Phipps.

Petitions to intervene were filed by Carolina Utility Customers Association, Inc. (CUCA) on June 17, 2020, by North Carolina Sustainable Energy Association (NCSEA) on June 25, 2020, by Sierra Club on August 5, 2020, and by Carolina Industrial Group for Fair Utility Rates II (CIGFUR) on August 25, 2020. The Commission granted CUCA's petition to intervene on June 18, 2020, NCSEA's petition to intervene on June 26, 2020, Sierra Club's petition to intervene on August 6, 2020, and CIGFUR's petition to intervene on August 25, 2020.

On June 29, 2020, the Commission entered an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. That Order provided that direct testimony of intervenors should be filed on or before August 25, 2020, that rebuttal testimony should be filed on or before September3, 2020, and that a hearing on this matter would be held on September 15, 2020. On September 14, 2020, DEP filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's procedural order issued on June 29, 2020.

On August 7, 2020, the Commission issued an Order Scheduling Remote Hearings for Expert Witness Testimony due to the COVID-19 pandemic. All parties subsequently filed notices consenting to remote hearings.

On August 21, 2020, DEP filed the supplemental testimony and revised exhibits and workpapers of Dana M. Harrington.

On August 24, 2020, Sierra Club filed a motion for an extension of time to file testimony until August 27, 2020, noting in consequence the request for an extension of time for DEP to file rebuttal testimony until September 10, 2020. The Commission granted both requests on August 25, 2020.

The intervention of the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e). On August 25, 2020, the Public Staff filed the testimony and exhibit of Dustin R. Metz and the affidavit of Jenny X. Li, in accordance with N.C.G.S. § 62-68.

On August 27, 2020, Sierra Club filed the testimony and exhibits of John A. Rosenkranz.

On September 10, 2020, DEP filed the rebuttal testimony of Dana M. Harrington and James J. McClay, III.

On September 11, 2020, DEP, the Public Staff, and Sierra Club filed a joint motion requesting that the Commission excuse DEP's witnesses Regis Repko, Kenneth D. Church, Kelvin Henderson, Brett Phipps, Dana M. Harrington, and James J. McClay III, the Public Staff's witness Dustin R. Metz and affiant Jenny X. Li, and Sierra Club's witness John A. Rosenkranz from appearing at the September 15, 2020, evidentiary hearing, and accept the expert witnesses' testimony and exhibits into the record, representing that all parties to the proceeding had agreed to waive cross-examination of DEP's witnesses, the Public Staff's witness and affiant, and Sierra Club's witness. On September 11, 2020, the Commission issued an order that excused all expert witnesses from appearing at the evidentiary hearing, received the witnesses' prefiled testimony, exhibits, and affidavits into the record, and canceled the expert witness hearing. The order also required that the parties file proposed orders, or briefs, on or before October 16, 2020.

The case came on for hearing as scheduled on September 15, 2020, for the purpose of accepting public witness testimony.No public witnesses appeared at the hearing. The Public Staff and DEP filed a joint proposed order on October 16, 2020. On that same date, the Sierra Club filed a post-hearing brief.

Based upon the verified application, testimony, and exhibits of the Company, the testimony, affidavit, and exhibit of the Public Staff, and the testimony and exhibits of Sierra Club that were received into the record, 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.G.S. § 62-133.2.

2. The test period for purposes of this proceeding is the 12 months ended March 31, 2020 (test period).

3. In its application and testimony in this proceeding, DEP requested a total decrease of $140.8 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 Experience Modification Factor (EMF) riders to take into account fuel and fuel-related cost under-recoveries experienced during the test period of $64.9 million. This balance is net of an under-recovered balance of $41.5 million, incurred during the months of April through June of 2019, which was included in the EMF balance within the update period in DEP's 2019 rider proceeding, Docket No. E-2, Sub 1204. This balance also includes the deferred under-recovered balance of $7.3 million in losses on the sale of by-products, which were approved for cost recovery

through the fuel clause in the Commission's Order Allowing Recovery of Liquidated Damages and Transportation Costs dated July 28, 2020, in Docket No. E-2, Sub 1204.

4. In its direct supplemental testimony and supplmental 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 $141.2 million, which included an updated under-recovered EMF of $64.8 million.

5. The Company's baseload plants were managed prudently and efficiently during the test period so as to minimize fuel and fuel-related costs.

6. The Company's fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent.

7. The test period per book system sales are 61,765,556 megawatt-hours (MWh). The test period per book system generation (net of auxiliary use and joint owner generation) and purchased power is 69,839,648 MWh and is categorized as follows:

Net Generation Type	MWh
Nuclear	28,861,332
Natural Gas, Oil, and Biogas	21,827,253
Coal	8,371,720
Hydro – Conventional	662,207
Solar	258,435
Purchased Power – subject to economic dispatch or curtailment	3,413,330
Other Purchased Power	6,445,371
Total Net Generation (may not add to sum due to rounding)	69,839,648

8. The appropriate nuclear capacity factor for use in this proceeding is 94.46%.

9. The North Carolina retail test period sales, adjusted for weather and customer growth, for use in calculating the EMF are 37,852,870 MWh. The normalized test period North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Normalized Test Period MWh Sales
Residential	16,191,429
Small General Service	1,777,668
Medium General Service	10,949,334
Large General Service	8,584,996
Lighting	349,444
Total (may not add to sum due to rounding)	37,852,870

10. The projected billing period (December 2020-November 2021) sales for use in this proceeding are 61,484,301 MWh on a system basis and 37,750,364 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 Billing Period MWh Sales
Residential	16,171,290
Small General Service	1,784,993
Medium General Service	10,287,749
Large General Service	9,128,353
Lighting	377,978
Total (may not add to sum due to rounding)	37,750,364

11. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 67,439,293 MWh and is categorized as follows:

Generation Type	MWh
Nuclear	29,730,338
Gas Combustion Turbine (CT) and Combined Cycle (CC)	18,943,545
Coal	7,940,674
Hydro	650,353
Solar	256,176
Purchased Power	9,918,206
Total (may not add to sum due to rounding)	67,439,293

12. 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 total nuclear fuel price is $6.20/MWh.
B. The gas CT and CC fuel price is $25.88/MWh.
C. The coal fuel price is $30.59/MWh.
D. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $20,467,213.
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 $458,166,122.
F. System fuel expense recovered through intersystem sales is $82,750,327.

13. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $808,620,116.

14. The Company's appropriate North Carolina retail jurisdictional fuel and fuel related expense under-collection for purposes of the EMF is $64,754,391, consisting of under-

recoveries of $29,153,931, $863,226, $10,505,756, $22,900,801, and $1,330,678, for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively. These amounts include the deferred under-recovered losses on the sale of by-products from the prior year as follows: $3,080,009, $375,378, $2,123,029, $1,614,722, and $67,033, for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively.

15. The decrease in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-2, Sub 1204 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.

16. 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: 2.080¢/kilowatt-hour (kWh) for the Residential class; 2.126¢/kWh for the Small General Service class; 2.228¢/kWh for the Medium General Service class; 2.204¢/kWh for the Large General Service class; and 1.392¢/kWh for the Lighting class.

17. The appropriate EMFs established in this proceeding, excluding the regulatory fee, are as follows: 0.180¢/kWh for the Residential class; 0.049¢/kWh for the Small General Service class; 0.096¢/kWh for the Medium General Service class; 0.267¢/kWh for the Large General Service class; and 0.381¢/kWh for the Lighting class.

18. 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: 2.260¢/kWh for the Residential class; 2.175¢/kWh for the Small General Service class; 2.324¢/kWh for the Medium General Service class; 2.471¢/kWh for the Large General Service class; and 1.773¢/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

N.C.Gen.S. § 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 filing in this proceeding was based on the 12 months ended March 31, 2020.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is contained in the application, the direct testimony of Company witness Harrington, 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 supplemental direct testimony of Company witness Harrington. This finding is not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is contained in the testimony of Company witnesses Henderson and Repko 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 North American Electric Reliability Corporation (NERC) Generating Availability Report, 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 a system average capacity factor of 91.79% during the test period. Neither this annual capacity factor, nor the Company's two-year average capacity factor of 90.50%, met the five-year industry weighted average capacity factor of 92.72% for the period 2014-2018 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Unit Statistical Brochure. The current test period included three refueling outages and nuclear units were removed from service in response to hurricane force winds for the second consecutive year.

To rebut the presumption of imprudence under Rule R8-55(k), Company witness Henderson addressed two particular unplanned outages. First, he testified that the most significant unplanned outage during the test period resulted from a 23-day outage at the Robinson plant. According to his testimony, an investigation determined that the main generator exciter failed suddenly with no prior indication of problems. Periodic inspections prior to the failure found no significant deficiencies. In addition, the Company's post-event investigations determined that prior inspections and preventative and corrective maintenance were performed correctly. Witness Henderson testified that this outage was unpredictable and unpreventable. Second, witness Henderson described the hurricane-related and unplanned outages at both Brunswick units during the test period. Excluding the Robinson outage caused by the unforeseeable exciter failure and the Brunswick outages attributable to Hurricane Dorian, witness Henderson stated that the Company would have achieved a test period nuclear capacity factor of 93.56%, which would exceed the NERC 5-year average of 92.72%. Witness Henderson testified that this evidence supports the Company's belief that it operated its nuclear plants in a safe, reliable, and prudent manner during the test period.

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 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.

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 Availability Brochure for the period 2014 through 2018:

Generator Type	Measure	Review Period	2014-2018	Nbr of Units
		DEP Operational Results	NERC Average	
Coal-Fired Test Period	EAF	76.3%	80.7%	399
	NCF	27.1%	56.3%	
	EFOR	5.5%	8.6%	
Coal-Fired Summer Peak	EAF	91.8%	n/a	n/a
Total CC Average	EAF	81.6%	84.9%	333
	NCF	66.0%	53.6%	
	EFOR	0.77%	5.1%	
Total CT Average	EAF	82.7%	87.5%	750
	SR	98.7%	98.3%	
Hydro	EAF	64.9%	80.2%	1,063

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 62% of the DEP fossil/hydro generation during the test period.

Public Staff witness Metz noted that the Company did not meet the standard found in Commission Rule R8-55(k). However, based on his review of the specifics that caused or contributed to the outages, Hurricane Dorian related outages, and Company actions from both a technical and commercial aspect, he testified that the overall costs and plant performances for the test period were adequate.

The Commission concludes that DEP successfully rebutted the presumption of imprudence under Commission Rule R8-55(k) through the testimony of Company witness Henderson as described above. Further, there was no evidence to the contrary and no party challenged the prudency of the operation of the Company's baseload units. Therefore, the Commission finds and concludes that DEP managed and operated its baseload plants prudently and efficiently to minimize its fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

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, 2020. 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, Church, Phipps, and Repko.

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 diverse generating portfolio mix of nuclear, natural gas, coal, and hydro; lower natural gas and coal prices; the capacity factors of its nuclear fleet; the combination of DEP's and DEC's respective expertise in procuring, 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 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.

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, 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, 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 3%, from $84.81 per ton in the prior test period to $86.94 per ton in the test period.

The Company's transportation costs decreased approximately 3%, from $32.72 per ton in the prior test period to $31.76 per ton in the test period.

Witness Phipps stated that DEP's current coal burn projection for the billing period is 3.3 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 $74.41 per ton for the billing period compared to $86.94 per ton in the test period.

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 135.0 million MMBtu, which is a decrease from the 166.6 million MMBtu consumed during the test period. The current average forward Henry Hub price for the billing period is $2.64 per MMBtu, compared to $2.33 per MMBtu in the test period. Witness Phipps also testified that the Company's average price of gas purchased for the test period was $3.74 per MMBtu, compared to $4.05 per MMBtu in the prior test period, representing a decrease of approximately 8%.

In addition, in response to the Commission's November 25, 2019 Order Approving Fuel Charge Adjustment in Docket No. E-2, Sub 1204, witness Phipps testified to the results of the Company's review of historic price fluctuations and whether its current method of forecasting and hedging should be adjusted to mitigate the risk of significant under-recovery of fuel costs. Based on its evaluation, the Company determined that no adjustments were needed to its current method of forecasting or to its physical hedging program. However, the Company continues to refine and add modeling capabilities that will provide additional information to help with analyzing fuel forecasts and needed procurement activities, and associated ranges of potential costs. The Company also recommends extending financial hedging activities for a lower percentage in rolling years four and five to mitigate cost risks for customers as explained in more detail in Phipps Confidential Exhibit 4.

Sierra Club witness Rosenkranz testified regarding the natural gas supply costs that DEP was seeking to recover in this proceeding. Witness Rosenkranz did not recommend any changes to the Company's proposed fuel rates. However, witness Rosenkranz testified concerning certain alleged deficiencies in DEP's fuel application and monthly reports and further alleges that some unspecified portion of DEP's long-term contracts for natural gas transportation are not needed.

In rebuttal testimony, Company witness Harrington testified that the Company's fuel rider application, including the supporting testimony, exhibits, and workpapers, fully complies with applicable law and provides sufficient information to demonstrate the reasonableness and prudence of the Company's fuel costs, including its natural gas costs. Company witness McClay testified that the Company's firm transportation (FT) provides the underlying framework for the Company to manage the natural gas supply needed to provide reliable, cost-effective generation for its customers, and that customers receive benefits from the Company's FT in the form of lower cost gas supply, intraday supply adjustments at minimal cost, and mitigation of punitive pipeline imbalance penalties. Witness McClay further noted that witness Rosenkranz made generalized statements concerning the Company's FT but never actually renders a specific recommendation that the Company should exit a particular FT arrangement. Therefore, in the context of this proceeding, there is no specific recommended action for the Commission to consider. Witness McClay further asserted that even if witness Rosenkranz was making a specific FT recommendation, his testimony was deficient in terms of the rigor and depth of analysis that would be required to support such a recommendation.

Section 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 8,933 MWs of generating capacity, 3,166 MWs of which is coal-fired generation across two generating stations and a total of five 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 varies depending on the generation output of the unit, the chemical constituents in the fuel burned, or the level of emissions reduction required.

Sections 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.

The Commission does not find the testimony of Sierra Club witness Rosenkranz to be persuasive with regard to any specific action. First, witness Rosenkranz has not recommended any adjustment to the fuel factors proposed in this proceeding. Second, the Commission agrees with Company witness Harrington that the sufficiency of the Company's fuel application should be evaluated based on the requirements of applicable law. Intervenors have the right to request any additional information they believe to be necessary through the well-established discovery process. The scope and level of detail contained in the Company's application, testimony, exhibits, and workpapers as filed in this proceeding conforms with applicable law and is consistent with prior applications. The Commission previously declined to accept nearly identical recommendations raised by Sierra Club in the 2020 Duke Energy Carolinas LLC's fuel application (Docket No. E-7, Sub 1228) and similarly declines to adopt such recommendations in this proceeding. Furthermore, witness Rosenkranz has not actually made a recommendation concerning a specific FT arrangement that is imprudent, and the Commission agrees with witness McClay that witness Rosenkranz' generalized observations regarding capacity release markets and the Companies' ability to obtain capacity and delivered gas historically does not provide a sufficient basis to take action, particularly given that witness Rosenkranz made no attempt to assess the Company's needs and the reliability risks associated with such market reliance nor to assess the unique operational challenges that have arisen and are likely to worsen due to the fully subscribed nature of the existing interstate pipelines as was further described by Company witness McClay.

Aside from Sierra Club, no party presented testimony contesting the Company's fuel and reagent procurement and power purchasing practices. Based upon the fuel procurement practices report, the evidence in the record, and the absence of any testimony to the contrary, the Commission concludes that these practices were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Harrington.

According to the exhibits sponsored by Company witness Harrington, the test period per book system sales were 61,765,556 MWh, and test period per book system generation and purchased power amounted to 69,839,648 MWh (net of auxiliary use and joint owner generation). The test period per book system generation and purchased power are categorized as follows (Harrington Exhibit 6):

Net Generation Type	MWh
Nuclear	28,861,332
Natural Gas, Oil and Biogas	21,827,253
Coal	8,371,720
Hydro – Conventional	662,207
Solar	258,435
Purchased Power – subject to economic dispatch or curtailment	3,413,330
Other Purchased Power	6,445,371
Total Net Generation (may not add to sum due to rounding)	69,839,648

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 61,765,556 MWh and system generation and purchased power of 69,839,648 MWh are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

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 94.46% 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 2020-2021 billing period. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 92.72% for the period 2014-2018 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 94.46% 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 94.46% nuclear capacity factor, and its associated generation of 29,730,338 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. 9-11

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Harrington.

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 37,852,870 MWh, comprised of Residential class sales of 16,191,429 MWh, Small General Service sales of 1,777,668 MWh, Medium General Service sales of 10,949,334 MWh, Large General Service sales 8,584,996 MWh, and Lighting class sales of 349,444 MWh.

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 Revised Harrington Exhibit 2, Schedule 1, is 61,484,301 MWh. The projected level of generation and purchased power used was 67,439,293 MWh (calculated using the 94.46% 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	MWh
Nuclear	29,730,338
Gas Combustion Turbine and Combined Cycle	18,943,545
Coal	7,940,674
Hydro	650,353
Solar	256,176
Purchased Power	9,918,206
Total (may not add to sum due to rounding)	67,439,293

As part of her Revised 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 MWh Sales
Residential	16,171,290
Small General Service	1,784,993
Medium General Service	10,287,749
Large General Service	9,128,353
Lighting	377,978
Total (may not add to sum due to rounding)	37,750,364

These class totals were used in Revised Harrington 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 weather and customer growth), 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. 12

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses Harrington and Phipps and the testimony of Public Staff witness Metz.

In her Exhibit 2, Schedule 1, Company witness Harrington recommended the fuel and fuel-related prices and expenses. 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 testimony, Public Staff witness Metz stated that, based on his investigation, the projected fuel and fuel-related costs (including reagents) set forth in DEP's application and testimony are reasonable and in accordance with the requirements of N.C.Gen. Stat. § 62-133.2.

No other party presented evidence on the level of DEP'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 Harrington 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. 13

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Harrington and the testimony of Public Staff witness Metz.

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 $808,620,116. Public Staff witness Metz 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 $808,620,116 is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-18

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Harrington, and the testimony and affidavit of Public Staff witness Metz and affiant Li.

Company witness Harrington presented DEP's original fuel and fuel-related expense (over)/under-collection and prospective fuel and fuel-related cost factors. Company witness Harrington's testimony sets forth the projected fuel and fuel-related costs, the amount of (over)/under-collection for purposes of the EMF, the method for allocating the decrease in fuel and fuel-related costs, the composite fuel and fuel-related cost factors, and EMFs, along with supplemental revised exhibits and workpapers. Public Staff affiant Li agreed that DEP's EMF increment/(decrement) riders for each customer class should be approved based on the following under-recoveries, which include the deferred under-recovered losses on the sale of by-products of $7.3 million from the prior year fuel Docket No. E-2, Sub 1204:

N.C. Retail Customer Class	Under-Recovery
Residential	$29,153,931
Small General Service	863,226
Medium General Service	10,505,756
Large General Service	22,900,801
Lighting	1,330,678
Total (may not add to sum due to rounding)	$64,754,391

As a result of these amounts, Public Staff affiant Li recommended approval of the following EMF increment/(decrement) billing factors, excluding the regulatory fee:

N.C. Retail Customer Class	EMF Increment/ (Decrement) (cents/kWh)
Residential	0.180
Small General Service	0.049
Medium General Service	0.096
Large General Service	0.267
Lighting	0.381

The Commission concludes that the EMF increment/(decrement) billing factors as set forth in the affidavit of Public Staff affiant Li are reasonable and appropriate for use in this proceeding.

Company witness Harrington calculated the Company's proposed fuel and fuel-related cost factors using a uniform bill adjustment method. She stated that the decrease in fuel costs from the amounts approved in Docket No. E-2, Sub 1204 should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology utilized in past DEP fuel cases approved by this Commission. No party opposed the use of this allocation method. Public Staff witness Metz recommended the approval of the prospective and total fuel and fuel-related cost factors (excluding regulatory fee) set forth in the supplemental testimony of Witness Harrington.

Based upon the testimony and exhibits in the record, the Commission concludes that DEP's projected fuel and fuel-related cost of $808,620,116 for the North Carolina retail jurisdiction for use in this proceeding is reasonable. The Commission also concludes that the EMF increment/(decrement) riders for each class set forth in the affidavit of Public Staff witness Metz and the affidavit of Public Staff affiant Li in this proceeding, excluding the regulatory fee, and the Public Staff's prospective fuel and fuel-related cost factors proposed in this proceeding for each of the rate classes, are appropriate. Additionally, the Commission concludes that DEP's decrease in fuel and fuel-related costs from the amounts approved in Docket No. E-2, Sub 1204 should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology approved by this Commission in DEP's past fuel cases.

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 calculation, incorporating the conclusions reached herein, results in net fuel and fuel-related cost factors of 2.260¢/kWh for the Residential class, 2.175¢/kWh for the Small General Service class, 2.324¢/kWh for the Medium General Service class, 2.471¢/kWh for the Large General Service class, and 1.773¢/kWh for the Lighting class, excluding regulatory fee, consisting of the prospective fuel and fuel-related cost factors of 2.080¢/kWh, 2.126¢/kWh, 2.228¢/kWh, 2.204¢/kWh, and 1.392¢/kWh, and EMF increments/(decrements) of 0.180¢, 0.049¢, 0.096¢, 0.267¢, and 0.381¢/kWh for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively, all excluding the regulatory fee. The billing factors, both excluding and including the regulatory fee, are shown in Appendix A to this order.

IT IS, THEREFORE, ORDERED:

1. That, effective for service rendered on and after December 1, 2020, 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 0.087¢/kWh, 0.038¢/kWh, (0.203)¢/kWh, (0.049)¢/kWh and 0.796¢/kWh, respectively, and further, that DEP shall adjust the resulting approved prospective fuel and fuel-related cost factors by EMF increments/(decrements) of 0.180¢/kWh for the Residential class, 0.049¢/kWh for the Small General Service class, 0.096¢/kWh for the Medium General Service class, 0.267¢/kWh for the Large General Service class, and 0.381¢/kWh for the Lighting class (excluding the regulatory fee). The EMF increments are to remain in effect for service rendered through November 30, 2021;

2. 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, 2020, as soon as practicable, but not later than ten days after the date that the Commission issues orders in this docket as well as in Docket Nos. E-2, Subs 1251, 1253, and 1254; and

3. That DEP shall work with the Public Staff to jointly prepare a proposed notice to customers of the rate adjustment ordered by the Commission in this Docket, as well as in Docket Nos. E-2, Subs 1251, 1253, and 1254, and the Company shall file the proposed notice to customers for Commission approval as soon as practicable.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of November, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

ELECTRIC – ADJUSTMENTS OF RATES/CHARGES

APPENDIX A

Rates in ¢/kWh excluding regulatory fee:						
	A	B	C	D	E	F
Class	Base Fuel Rate	Increment / (Decrement) to Base Fuel Rate	Prospective Rate: Columns A+B	EMF Increment / (Decrement)	EMF Interest (Decrement)	Billed Rate: Columns C+D+E
Residential	1.993	0.087	2.080	0.180	-	2.260
Small General Service	2.088	0.038	2.126	0.049	-	2.175
Medium General Service	2.431	(0.203)	2.228	0.096	-	2.324
Large General Service	2.253	(0.049)	2.204	0.267	-	2.471
Lighting	0.596	0.796	1.392	0.381	-	1.773

Rates in ¢/kWh including regulatory fee:						
	A	B	C	D	E	F
Class	Base Fuel Rate	Increment / (Decrement) to Base Fuel Rate	Prospective Rate: Columns A+B	EMF Increment / (Decrement)	EMF Interest (Decrement)	Billed Rate: Columns C+D+E
Residential	1.996	0.087	2.083	0.18	-	2.263
Small General Service	2.091	0.038	2.129	0.049	-	2.178
Medium General Service	2.434	(0.203)	2.231	0.096	-	2.327
Large General Service	2.256	(0.049)	2.207	0.267	-	2.474
Lighting	0.597	0.797	1.394	0.381	-	1.775

DOCKET NO. E-7, SUB 1242

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Application of Duke Energy Carolinas, LLC for Authorization under N.C. Gen. Stat. § 62-161 to Issue and Sell Securities	)))	ORDER GRANTING AUTHORITY TO ISSUE AND SELL ADDITIONAL SECURITIES

BY THE COMMISSION: Duke Energy Carolinas, LLC (the Company) filed an Application on September 3, 2020 requesting authorization under N.C. Gen. Stat. § 62-161 to issue and sell a maximum of $4,000,000,000 aggregate principal amount of securities of all or any combination of Proposed Debt Securities, Long-Term Bank Borrowings, Tax Exempt Bond Obligations, Lease Financing 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 Progress, LLC, Duke Energy Florida, LLC, Duke Energy Indiana, LLC, Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., and Piedmont Natural Gas Company, Inc. In addition, Duke Energy Corporation owns various nonregulated energy businesses located primarily in the U.S.

2. The Company's existing outstanding long-term debt principally consists of First and Refunding Mortgage Bonds, Senior Debt, Tax Exempt Bond Obligations and Other Long-Term Debt. A schedule of all such Bonds, Senior Debt, Tax Exempt Bond Obligations and Other Long-Term Debt outstanding as of March 31, 2020 is attached to the Application as Exhibit A. All of the outstanding First and Refunding Mortgage Bonds were issued under the terms of a First and Refunding Mortgage dated as of December 1, 1927, from the Company to The Bank of New York Mellon Trust Company, N.A., as trustee, as supplemented and amended by various Supplemental Indentures (hereafter sometimes referred to as the Mortgage), copies all of which have been filed with this Commission. Substantially all of the Senior Debt consists of Senior

Notes issued under a Senior Indenture to The Bank of New York Mellon, dated as of September 1, 1998 (the Senior Indenture).

The Tax Exempt Bond Obligations resulted when the Company borrowed the proceeds of the sale of tax exempt pollution control or solid waste disposal revenue bonds issued by various governmental authorities pursuant to authorization granted by this Commission.

The Other Long-Term Debt includes a financing arrangement utilizing commercial paper backed by the long-term credit facility described in Section 4(ii) below and certain borrowings under the Money Pool Agreement approved by the Commission in Docket No. E-7, Sub 986A.

3. The Company proposes to issue, sell, incur or undertake from time to time a maximum of $4,000,000,000 aggregate principal amount of all or any combination of Proposed Debt Securities, Long-Term Bank Borrowings, Tax Exempt Bond Obligations, and Lease Financing 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 and Refunding Mortgage Bonds.

To the extent the Proposed Debt Securities are Senior Notes, they will be created and issued under the Senior Indenture as heretofore supplemented or as further supplemented by a Supplemental Indenture to be executed in connection with their issuance.

To the extent the Proposed Debt Securities are Subordinated Notes, they will be created and issued under the Company's Subordinated Indenture to the Bank of New York Mellon, as Trustee, dated as of December 1, 1997, as heretofore supplemented or as further supplemented by a Supplemental Indenture to be executed in connection with their issuance.

To the extent the Proposed Debt Securities are the Company's First and Refunding 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 and Refunding 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) ***<u>Long-Term Bank Borrowing</u>***

The Company further seeks permission to make long-term borrowings under its Master Credit Facility (Long-Term Bank Borrowings). As of July 31, 2020, the Company currently has a $1.5 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 $1.75 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, 2025. 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) ***<u>Tax Exempt Bond Obligations</u>***

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) ***<u>Finance Lease Obligations</u>***

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.

ELECTRIC – CERTIFICATE

Leases may be used to finance the construction or 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 amount 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 may obtain third-party lease financing for the original purchase or refinancing of Property acquisitions, and an agreement may 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 may 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 may 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) ***Interest Rate Management Agreements***

As described in its Applieation for Amended Order dated June 29, 2009, in Docket No. E-7, Sub 862 (the Amendment Application), the Company utilizes various techniques to manage the interest costs it incurs in connection with its financial obligations. Although the Company states that it is unclear whether or not such activities constitute the issuance of securities within the meaning of Section 62-161 of the North Carolina General Statutes, the Company nevertheless has requested that the Commission grant it authority to utilize interest rate management techniques and enter into Interest Rate Management Agreements to manage its interest costs. As discussed in the Amendment Application, having explicit Commission authority for such agreements will allow the Company to be able to defer the mark-to-market impact of Interest Rate Management Agreements under Statement of Financial Accounting Standards 71. Such authority will allow the Company sufficient alternatives and flexibility in effectively managing interest rate risk.

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 statute or Commission order. Therefore, entry into a given Interest Rate Management Agreement itself will not reduce the amount of "shelf" authority under a Commission order governing such a debt security.

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 terms to the Company for any issuance and sale of the Proposed Securities. Certain types of the Proposed Securities, such as bank borrowings, leases and interest rate management agreements, are not typically "sold" in a public or private offering.

5. The authority requested by the Company is to replenish the authority previously granted under the Commission's order in Docket No. E-7, Sub 1176, of which $3,624,819,038 has been utilized. The Company requests that the remaining authority granted in such docket be terminated and subsumed within the authority which may be granted under the Commission's order in this docket.

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-7, Sub 986A. 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 basis closure costs.

The Company connected approximately 54,370 new customers in 2019 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 89.9 million and 92.3 million megawatt hours for 2019 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 (including expenditures for the acquisition of nuclear fuel) were $2.7 billion and $2.7 billion for each of 2019 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 of its existing generation plants, construction of new electric generation plants, modernization of the electric grid, and coal ash basin closure costs. During the period 2020 through 2024, the

Company plans to invest approximately $16.2 billion in its electric plant, including grid modernization and coal ash basin closure costs. Adequate financing authority as applied for in this proceeding 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 corporate 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 corporate purposes.

IT IS THEREFORE ORDERED that the Company is hereby authorized, empowered, and permitted to:

1. Issue and sell up to $4,000,000,000 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-7, Sub 986A.

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 dated August 16, 2018 in Docket No. E-7, Sub 1176 is hereby terminated and that Docket No. E-7, Sub 1176 is hereby closed.

ISSUED BY ORDER OF THE COMMISSION
This the 29th day of September, 2020.

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 30, 2020, Duke Energy Carolinas, LLC (DEC or the Company), made a filing proposing its annual change to the Existing DSM Program Rider (EDPR), based on the December 31, 2019, legacy demand-side management (DSM) deferral account balance. The Company requested that the EDPR be effective beginning July 1, 2020.

An EDPR was first approved in DEC's general rate case in Docket No. E-7, Sub 828 (the 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 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 30, 2020 filing, DEC indicated that during calendar year 2019, the applicable base rate amount was 0.0067 cents per kWh,[1] as reaffirmed pursuant to the Commission's June 25, 2019, Order in general rate case Docket No. E-7, Sub 1146.

In its March 30, 2020 filing, DEC proposed to replace the existing EDPR decrement rider amount of (0.0043) cents per kWh (excluding the regulatory fee),[2] with a new decrement rider amount of (0.0007) cents per kWh (excluding the regulatory fee), to be effective on and after July 1, 2020.

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 filing. Adjusting for the regulatory fee does not result in a change to either the base amount or the rider amount proposed in this proceeding. Therefore, 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 (0.0007) cents per kWh, and the current decrement rider, including the regulatory fee, of (0.0043) cents per kWh, or a net rate increase of 0.0036 cents per kWh.

[1] Except as otherwise indicated, all rates are excluding the North Carolina regulatory fee.

[2] The existing EDPR decrement rider was allowed to become effective as of July 1, 2019, pursuant to Commission Order in these dockets.

This matter was presented to the Commission at its Regular Staff Conference on June 15, 2020. 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 for the period July 1, 2020, through June 30, 2021.

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, 2020.

IT IS, THEREFORE, ORDERED that the EDPR proposed by DEC in its filing of March 30, 2020, consisting of a rate decrement of (0.0007) cents per kWh excluding the regulatory fee [(0.0007) cents per kWh, including the regulatory fee], is approved effective July 1, 2020, through June 30, 2021.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of June, 2020.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

DOCKET NO. E-2, SUB 1095D
DOCKET NO. E-7, SUB 1100D
DOCKET NO. G-9, SUB 682D

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Third-Party Independent Audits of Affiliate	)	ORDER APPROVING
Transactions Pursuant to Regulatory	)	AUDITOR AND REQUIRING
Condition No. 5.8	)	PROCEDURAL SCHEDULE

BY THE CHAIR: On September 29, 2016, the Commission issued an Order Approving Merger Subject to Regulatory Conditions and Code of Conduct (Merger Order), in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682, approving the merger of Duke Energy Corporation and Piedmont Natural Gas Company, Inc. Included among the Regulatory Conditions (RCs) approved in the Merger Order is RC No. 5.8. This RC requires, among other things, that a third-party independent audit be conducted regarding the affiliate transactions among Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Piedmont (collectively, Duke utilities) no less than every two years.

Subsection (b) of RC No. 5.8 requires that the Public Staff propose one or more independent auditors. The Duke utilities and other parties then have an opportunity to propose additional auditors.

On January 15, 2020, the Public Staff filed its auditor proposal recommending that Schumaker & Company be chosen as the third-party independent auditor. The Public Staff stated that the Duke utilities agreed with the Public Staff's recommendation.

On January 24, 2020, the Commission issued an Order Allowing Comments on Proposed Auditor. The order allowed interested parties to file comments and/or the names and audit proposals of additional independent auditors on or before February 10, 2020. No comments were filed.

Based on the foregoing and the record, the Chair finds good cause to approve Schumaker & Company as the third-party independent auditor, as proposed by the Public Staff and agreed to by the Duke utilities. In addition, the Chair finds good cause to require the Public Staff and the Duke utilities to confer with one another and file for the Commission's consideration a proposed procedural schedule for the audit, including the date for the filing of the auditor's final report. Finally, the Chair finds good cause to direct that the Chief Clerk serve a copy of this Order on all parties to Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682.

IT IS, THEREFORE, ORDERED as follows:

1. That Schumaker & Company shall be, and is hereby, approved as the independent auditor to conduct the third-party audit regarding the affiliate transactions among Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Piedmont Natural Gas Company, Inc.

2. That on or before March 27, 2020, the Public Staff and the Duke utilities shall confer with one another and file for the Commission's consideration a proposed procedural schedule for the audit, including the date for the filing of the auditor's final report.

3. That the Chief Clerk shall serve a copy of this Order on all parties to Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of February, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

DOCKET NO. E-2, SUB 1167
DOCKET NO. E-7, SUB 1166

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC,	)	ORDER MODIFYING FOURTH
and Duke Energy Carolinas, LLC, for	)	YEAR OF SOLAR REBATE
Approval of Solar Rebate Program	)	PROGRAM AND REQUESTING
Pursuant to N.C. Gen. Stat. § 62-155(f)	)	ADDITIONAL COMMENTS

BY THE COMMISSION: Pursuant to Part VIII of House Bill 589 (Session Law 2017-192) enacting N.C.G.S. § 62-155(f), Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC (collectively, Duke or the Companies), jointly filed a proposed solar rebate program on January 22, 2018, which was approved by Commission order dated April 3, 2018. Pursuant to Ordering Paragraph No. 3 of that order, Duke is required to file an annual report on or before April 1 of each year including specific information about program participation and any proposed changes to the solar rebate program.

On April 1, 2020, Duke filed its solar rebate program annual report for calendar year 2019 and a request to amend program application windows for calendar years 2021 and 2022 (2019 Annual Report).

On April 7, 2020, the Commission issued an Order Allowing Comments on 2019 Annual Report. The following parties submitted comments on Duke's 2019 Annual Report: the Public Staff, the Southern Alliance for Clean Energy (SACE), and the North Carolina Sustainable Energy Association (NCSEA). In addition, Southern Energy Management, Pisgah Energy, Inc., 8M Solar, Palmetto Clean Technology, and Eagle Solar and Light filed statements of position primarily in support of NCSEA's comments. Reply comments were filed by the Public Staff, Duke, SACE, and NCSEA. Both Duke and the other commenters recommend that changes are needed in the fourth and fifth years of the solar rebate program.

INTRODUCTION

Subsections (1) through (3) of N.C.G.S. § 62-155(f) provide for solar rebates to residential and nonresidential (for-profit and nonprofit) customers totaling 10,000 kW of installed capacity annually for five years (calendar years 2018-2022), including an annual capacity cap of 5,000 kW for nonresidential customer installations, of which 2,500 kW is specifically set aside for nonprofit organizations. Further, N.C.G.S. § 62-155(f) limits the incentives for residential customer installations to 10 kW and nonresidential customer installations to 100 kW.

The solar rebate program is past its mid-point, having nearly completed three years with two years remaining. The program's costs are recoverable from ratepayers pursuant to the rider established in N.C.G.S. § 62-133.8(h). N.C.G.S. § 62-155(f).

For the initial three years, the program has included a single annual application window with rebates claimed on a first-come, first-served basis in the order the applications were received. Current incentives are as follows:

Customer Class	Current Rebate ($/W)	Maximum Capacity Eligible for Rebate	Maximum Rebate
Residential	0.60	10 kW	$6,000.00
Commercial	0.50	100 kW	$50,000.00
Nonprofit	0.75	100 kW	$75,000.00

The demand for the solar rebates is extraordinary and significantly exceeds the supply provided for in N.C.G.S. § 62-155(f) with the exception of the nonprofit customer class.

Duke experienced technical difficulties with its online solar rebate application process in 2020, explaining:

> [T]he Companies opened their application process for 2020 at 9:00 a.m. on January 2, 2020, and they reached non-residential and commercial maximum capacity limits at 9:19 a.m. for DEP and 9:21 a.m. for DEC on January 2, 2020. Applications received after 9:19 a.m. for DEP and 9:21 a.m. for DEC were placed on the waiting list. The Companies, however, quickly became aware of issues with the application process. The Companies realized that certain customers had been unable to submit their applications to the Companies through the webpages. The Companies investigated the issue and determined that their websites did not perform as expected due to a recent migration of infrastructure to the cloud. The surge in applications received at the opening of the window did not cause the technical issue, but it did exacerbate the then unknown, but still pre-existing, problem. Although users were provided with messages confirming their applications had been properly submitted, the form data was not successfully loaded into the Companies' database. Alternatively, some users did not receive any notifications. The Companies have been working through the issues, and when the Companies determine that a customer had applied before capacity was reached in their service territories, the customer's request for a solar rebate has been honored.

2019 Annual Report at 7-8.

PRIMARY RECOMMENDATIONS OF THE PARTIES

Additional Annual Application Window

In its 2019 Annual Report Duke states that in order to avoid a repeat of the technical difficulties experienced during the 2019 program application process, it is committed "to perform the necessary technical fixes" and further proposes "to include an additional application window to lessen the urgency of applying on January 2 and to spread the market over the course of a year." Further, Duke states:

> Feedback from installers and developers indicated that opening the application windows only on the first business day of the year has caused issues with selling solar systems throughout majority of that calendar year. To assist with selling systems throughout the year, the Companies propose releasing half of the capacity on the fifth business day of January and the other half of the annual capacity on the fifth business day of July. The waiting list from January would cancel on June 30, and the waiting list from July would cancel on December 31. Splitting the capacity would allow customers two opportunities per year to receive a rebate reservation, installers would be able to sell systems to customers year-round and this should decrease the volume of applications received on the day of the launch. It may also alleviate some of the traffic on the solar rebates page the first business day of the year.

2019 Annual Report at 8.

The Public Staff notes in its initial comments that Duke's proposal to add an additional annual application window "will necessarily increase the administrative costs associated with the Program," and the Public Staff recommends that if the Commission grants Duke's request that it also "reduce the residential and non-residential rebates in order to cover any increased administrative costs." Public Staff Initial Comments at 4.

The Public Staff also expresses concern that "instead of solving the problems experienced during the single enrollment window in 2020, some of the same challenges would be faced twice a year, instead of only once." *Id.* The Public Staff hypothesizes that "the solar industry would still experience a drop off of installations in the period between when the subscription limit is reached and the beginning of the 90-day window for the next enrollment period — similar to the current drop off experienced today." *Id.*

The Public Staff forecasts that adding a second application window will "likely increase the number of applications being both submitted and rejected each year, as well as creating two windows where solar rebate customers and installers would be competing in a very short timeframe for an even smaller amount of solar capacity available during each enrollment window . . . . " *Id.*

In their respective initial comments, NCSEA states that it supports biannual releases of capacity as proposed by Duke, and SACE states that it does not oppose Duke's proposal to include an additional application window in July.

In its reply comments Duke estimates that the administrative cost of adding a second round of applications would be $15,000, which it characterizes as a minimal increase compared to the total administrative cost of $500,000 for the program in 2019. Duke opposes the Public Staff's recommendation that the additional administrative cost be offset by reducing the residential and nonresidential rebates, contending that reducing rebates to offset the additional cost of a second application window "increase[s] the risk that customers who have already contracted for installation of solar systems based on the anticipated [sic] of a certain rebate amount will be further disadvantaged." Duke Reply Comments at 3.

In the Public Staff's reply comments it states that if the Commission is not inclined to transition to a lottery system, it does not object to Duke's proposal to add an additional annual application window so long as any additional administrative costs are either minimal or offset by reductions in the rebates.

In its reply comments NCSEA states that it does not oppose retaining a single annual application window.

Lottery System to Allocate Residential and Commercial Rebates

The Public Staff proposes that a better way to handle the significant competition for rebates within the residential and nonresidential customer classes "would be for Duke to change the way it awards solar rebates entirely, moving from a first-come-first-served program to a lottery program." *Id.* at 4-5. The Public Staff proposes that under a lottery system Duke would accept rebate applications for a set period and then randomly select applications until the subscription limits are reached or the applicant pool is exhausted. The Public Staff notes that utilities in other states have utilized lottery systems to address rebate programs where demand exceeded supply and that the New Hampshire Public Utilities Commission recently adopted a lottery system for its Renewable Energy Incentive Program for Commercial and Industrial Solar Projects. On the downside, the Public Staff notes that it "has raised the lottery approach with solar developers and Duke, and recognizes that the administrative time and costs of setting up such a proposal may pose challenges to implement over the final two years of the Program." *Id.* at 5. However, the Public Staff opines that "such changes may be appropriate to ensure that all customers interested in participating in the Program have equitable access to the limited supply of available incentives." *Id.*

In its reply comments Duke states that it is willing to implement the lottery system proposed by the Public Staff: "There are advantages and disadvantages to first-come, first-served systems and to lottery systems. Generally, first-come, first-served programs allow customers to have more control, while lottery systems avoid a frenzied rush and allow more opportunities to address issues which may arise." Duke Reply Comments at 1-2. Duke further states that it is "prepared to institute a lottery system for the remaining years of the program should the Commission adopt that approach." *Id.* at 4. Duke posits that "[w]hether the program is conducted as first-come, first-served program or as a lottery, biannual releases of capacity will assist solar installers with marketing on a more consistent basis," *id.* at 5, and requests that the Commission "allow the Companies to hold biannual lotteries in January and July for the remainder of the program." *Id.* at 7.

In its reply comments NCSEA expresses opposition to the Public Staff's lottery proposal, stating that "a lottery system would actually be more unfair for customers by doing away with what limited control they currently have over whether they will receive a rebate." NCSEA Reply Comments at 8. NCSEA states that its member solar installers are universally opposed to a lottery system:

> Under the current first-come, first-served paradigm, solar installers can work with their customers to ensure they have the greatest chance of receiving a rebate. For this reason, several of NCSEA's members are willing to bear the additional

> financial risk of offering to pay part of, or refund the value of, the rebate to a customer if they are unsuccessful in their application. By increasing the risk by moving from a first come, first-served system to a lottery system, it may be come untenable for installers to continue offering this benefit, causing prices to rise for all rooftop solar adopters. NCSEA and its members believe that moving to a lottery system will not drive customer participation or increase rooftop solar adoption.

Id. at 9.

NCSEA also opines that transitioning to a lottery system will increase the likelihood for additional technical issues. NCSEA finally states that if the Commission decides to adopt the Public Staff's lottery proposal that it also delay implementing the lottery system until the mid-year 2021 or 2022 application window and require Duke to file for Commission approval a lottery implementation plan, "including the costs associated with its implementation to demonstrate that the lottery approach costs less to implement than tbe current first-come, first-served system with which installers and customers are already familiar." *Id.* at 9-10.

Finally, SACE states its opposition to the Public Staff's lottery proposal, opining that switching to an entirely new system will lead to additional complications.

Maximum Capacity Eligible for Incentives

Regarding customer expectations for rebates, NCSEA states:

> [C]ustomers are signing contracts and installing rooftop solar without any expectation that they will receive a rebate. Given the fact that rebate allocations for the residential and nonresidential sectors have been exhausted in less than 90 minutes for the past two years, customers can no longer expect to receive a rebate. NCSEA's conclusion has been reinforced in conversations with its members, which has revealed that fewer installer companies are including the value of the rebate in the financial calculations that they provide to their customers.

NCSEA Initial Comments at 3. NCSEA opines, "If customers cannot depend on receiving a rebate, and are not factoring it into their financial decisions, then there is no harm in making changes now for the 2021 rebate allocation that will benefit more rooftop solar adopters." *Id.*

NCSEA further states that "the solar rebate program is no longer incenting customers to adopt rooftop solar because not enough customers are able to participate" and urges the Commission to adopt changes to the program to fulfill the legislative intent of N.C.G.S. § 62-155(f) — "to drive increased adoption of rooftop solar" — by taking "action to expand the number of customers who can participate in the program." *Id.* at 4.

NCSEA acknowledges that the "overall size" of the solar rebate program is determined by N.C.G.S. § 62-155(f); however, NCSEA proposes two cost-neutral changes to the program that it contends would "expand the number of customers who can participate in the rooftop solar rebate program" without violating the size limitations codified in N.C.G.S. § 62-155(f). *Id.* at 4. Per NCSEA,

> N.C. Gen. Stat. § 62-155(f) states that the solar rebate "incentive *shall be limited to* 10 kilowatts alternating current (kW AC) for residential solar installations and 100 kilowatts alternating current (kW AC) for nonresidential solar installations." (emphasis added). Notably, the statute does not say that the incentive *shall be* 10 kW and 100 kW. The General Assembly could have provided this direction to the Commission but chose not to do so. Instead, the General Assembly has afforded the Commission the discretion to change the maximum system size for rebate availability, so long as the maximum size does not exceed 10 kW AC for residential solar installations and 100 kW AC for non-residential solar installations.

Id. at 4-5.

NCSEA proposes to amend the solar rebate program requirements to have a maximum residential customer rebate of 5 kW and a maximum rebate of 50 kW for for-profit nonresidential customer installations. NCSEA clarifies that it does not propose any change to the nonprofit set-aside established by N.C. Gen. Stat. § 62-155(f)(3). NCSEA notes:

> Changing the limits for these systems to 5 kW and 50 kW would not double the supply of rebates, but would significantly increase the supply. The change would also be revenue neutral, since the cumulative capacity of these rebate allocations would be unchanged.

Id. at 5.

Alternatively, NCSEA proposes to change the rebate program to use a "1:1 ratio for rebate-eligible and rebate ineligible solar," in which

> every kW of installed solar capacity that is eligible for the rebate also be paired with a kW of installed solar capacity that is not eligible for the rebate, up to a 10 kW rebate for residential installations and a 100 kW rebate for nonresidential installations that are not nonprofit installations.

Id. at 6. NCSEA opines that such a change to the rebate program "substantially increases the number of ratepayers in these segments who would be able to participate in the solar rebate program; since rebates would be based on smaller eligible system sizes, more systems could be installed under the statutory limit contained in N.C. Gen. Stat. § 62-155(f)(1)." *Id.* NCSEA further notes that "by reducing the dollar amount of the rebates that ratepayers would receive, it also reduces the negative financial impact for customers who are waitlisted and ultimately do not receive a rebate." *Id.* As with its primary proposal, NCSEA does not propose that the 1:1 ratio apply to nonprofit customers.

NCSEA states that its proposed changes

> do not increase the overall cost of the rebate program, but could potentially increase administrative costs . . . . While any increase in administrative costs should be minimized, NCSEA notes that the overall costs of DEC and DEP's compliance with N.C. Gen. Stat. § 62-133.8 have consistently been below the cost

> caps established in N.C. Gen. Stat. § 62-133.8(h)(4). Accordingly, NCSEA believes that increases in administrative costs associated with greatly expanding the availability of solar rebates, which should be minor, are reasonable and warranted.

Id. at 10-11.

In its reply comments Duke notes:

> While NCSEA's proposals benefit solar installers by getting rebates to more participants, it [sic] appears to be more disruptive for residential and non-residential customers than the Public Staff's proposal. Whereas the Public Staff's proposal involves a minimal reduction to the incentives for residential and non-residential customers to provide extra incentive to non-profits, NCSEA's proposal essentially takes half of the existing incentives from eligible residential and non-residential customers to make room for more residential and non-residential customers, while providing no additional incentive for non-profits.

Duke Reply Comments at 6.

In its reply comments the Public Staff expresses opposition to NCSEA's proposed program changes, contending that NCSEA's proposal to modify the eligible size limitations is violative of the requirements set forth in N.C.G.S. § 62-155(f). The Public Staff opines that the statutory language of N.C.G.S. § 62-155(f) that the solar rebate incentive "shall be limited to 10 kilowatts alternating current (kW AC) for residential solar installations and 100 kilowatts alternating current (kW AC) for nonresidential solar installations" is a "recognition by the General Assembly of the reality that solar installation size and capacity will vary by each customer — for example, many residential installations will be less than 10 kW, but others will be larger." Public Staff Reply Comments at 4. The Public Staff argues that the General Assembly established an "upper threshold [of up to 10 kW for residential customers and 100 kW for non-residential customers] for determining the portion of an installation that would be eligible for the rebate." *Id.* The Public Staff contends that the plain language of the statute prohibits the Commission

> from adopting a limit on incentive eligibility that is less than the capacity amounts called for in the statute. If the Commission were to amend the rebate program such that only the first 5 kW of each residential installation or the first 50 kW of each nonresidential installation were eligible to receive the rebate, they would be substituting their judgment for that of the General Assembly over the appropriate amount of capacity to incentivize at each facility.

Id. at 5-6.

The Public Staff also objects to NCSEA's proposal to allow the incentive to be applicable to only one-half of the capacity at each facility:

> While on its face the proposal does not directly assign the incentive to more than 10,000 kW, from a practical perspective a solar rebate customer must install one kW to get the next one incentivized. This "BOGO" incentive structure is, in effect,

> still incentivizing every kW installed up to the eligibility limit, despite NCSEA's statements otherwise. In addition, by not applying the pro-rata approach to the capacity eligible for the non-profit set-aside established by the General Assembly, NCSEA's proposal would potentially result in a larger amount of capacity being incentivized for residential and non-residential customers, counter to the specific division of capacity established by the General Assembly. Further, proposing to limit the eligible capacity to only the first half of the capacity installed at each facility would likely prove confusing to customers and parties marketing the Solar Rebate Program, and may further complicate implementation of the Program for the remaining two years that it is offered.

Id. at 6.

While the Public Staff contends that "the plain language of the statute is clear and unambiguous" in prohibiting the modifications proposed by NCSEA, the Public Staff also argues that the legislative intent underlying HB 589 — including the net metering rates established via N.C.G.S. § 62-126.4 — further prohibits NCSEA's proposals:

> As part of its developing the comprehensive reforms enacted in H589, the General Assembly made a determination to further incentivize a specific capacity of net metered solar facilities through the Solar Rebate Program over the 2018-2023 timeframe, but also directed the electric public utilities to investigate "the costs and benefits of customer-sited generation" and for the Commission "to establish net metering rates under all tariff designs that ensure that the net metering retail customer pays its full fixed cost of service." These elements should be read *in pari materia* with the rest of H589 and cannot be viewed in isolation. Therefore, for the Commission to incentivize a larger amount of capacity through the Solar Rebate Program to be installed and receiving service under the current net metering tariff would be counter to the clear intent of the General Assembly in enacting these provisions in H589.

Id. at 7-8.

In its reply comments NCSEA disagrees with the Public Staff's interpretation of the General Assembly's legislative intent but does not addresses the Public Staff's primary position that the plain language of the statute is clear and unambiguous in prohibiting the modifications to the eligible size limitations proposed by NCSEA. First NCSEA distinguishes between interpreting a single statute using the principle of *in pari materia* and a session law, which modifies multiple statutes, as was the case with HB 589. NCSEA argues that the legislative intent behind HB 589 was to increase customer access to clean energy. NCSEA further argues that "the General Assembly intended for N.C. Gen. Stat. § 62-155(f) to encourage a specific behavior — the adoption of rooftop solar." NCSEA Reply Comments at 3. NCSEA argues:

> In implementing N.C. Gen. Stat. § 62-155(f), the Commission should consider this legislative intent to encourage and expand the adoption of rooftop solar. As the Commission is now faced with a decision to either adopt NCSEA's proposal to improve the program or the Public Staff's proposal to limit its effectiveness, the

> Commission should recognize the legislature's intent that the rooftop solar rebate program should encourage customers to adopt rooftop solar.

Id.

SACE states that it supports NCSEA's proposal to lower the limits on rebate- eligible solar installations to 5 kW for residential customers and 50 kW for commercial and industrial customers, and in its reply comments SACE argues that "there is good reason to believe that NCSEA's proposal would increase installations among residential and commercial or industrial customers by making more rebates available to satisfy pent- up demand, thereby increasing the success of the program and providing stability for the clean-energy industry in a time of significant economic uncertainty." SACE Reply Comments at 3.

Adjust Rebate Amounts

The Public Staff notes that the current incentive amounts were based in part on the price of installing solar systems in or around January 2018 and were designed "prior to the utilities gaining any experience in North Carolina on the customer response to the incentive amounts." Public Staff Initial Comments at 2. The Public Staff further notes:

> [T]he Lawrence Berkeley National Lab (LBNL) estimates that over the 2017-2018 period, residential and small nonresidential solar installations dropped across the country by a median of $0.20 per watt, which was consistent with trends over the prior five years. These estimates align with many other sources, which point to continued declines in solar installation costs across the country, including in North Carolina, although at a slower rate than from 2009-2014.

Id. As such, the Public Staff recommends adjusting the rebate amounts "to ensure that the incentives being offered for each customer class are reasonable[,]" and it proposes "a revenue-neutral adjustment" to reduce the residential and nonresidential rebates and increase the nonprofit rebates, as shown below. *Id.* at 3.

Customer Class	Current Rebate ($/W)	Proposed Rebate ($/W)	Current Maximum Rebate	Proposed Maximum Rebate	Delta
Residential	0.60	0.50	$6,000.00	$5,000.00	-17%
Commercial	0.50	0.40	$50,000.00	$40,000.00	-20%
Nonprofit	0.75	1.00	$75,000.00	$100,000.00	+33%

The Public Staff states that based on its estimates for the next two years, it believes that its proposal will result in increased participation from the nonprofit customer class and lower overall program costs for the residential and nonresidential customers classes. The Public Staff finally notes that reducing the residential and nonresidential rebates "may affect some customers who currently plan to install their systems beginning in October 2020 and would then be eligible to apply in January 2021; however, we note that rebates, including the specific amount of each rebate, is never guaranteed for any customer." *Id.*

Relevant to the Public Staff's proposal to change the dollar per watt rebate amounts, in its 2019 Annual Report Duke states that it has "not received complaints from stakeholders regarding the incentive amounts." 2019 Annual Report at 5. Duke notes that in its last program report it considered changing the incentive amounts for the 2021 program:

> In the past six months, however, the Companies have received two strong indications that non-profits needed more time than for-profit entities to participate in the program, not that non-profits were seeking an increased rebate amount to spur participation. First, solar developers now report that non-profits have secured their funding and are ready to move forward on projects. Second, North Carolina city and county governments have reported that they will be utilizing the rebates program to help them achieve their sustainability goals. The Companies have also observed an increase in the percentage of residential and nonresidential customers installing their projects prior to receiving a rebate application from 2019 (39%) to 2020 (50%). This indicates to the Companies that customers are signing contracts with the expectation that the current rebate value will be in place when they receive their rebate.

Id. at 6. For these reasons, Duke hypothesizes that

> customers could be harmed, based on their expectations, by changing the rebate for the 2021 program opening. Rather than potentially disrupt expectations in marketplace in 2021, the Company is open to changing the rebate amounts in 2022. Thus, the Companies have concluded that changes to the rebate incentive amounts are not necessary at this time.

Id.

In its reply comments Duke revises its position — that the rebate amounts should not be adjusted — and states that it supports the Public Staff's recommendation to modify the rebate amounts.

While NCSEA recommends other alterations to the rebate structure for residential and commercial customers — modifying the maximum capacity eligible for the incentive — it does not recommend changing the existing rebate amounts of $0.60/kW and $0.50/kW for residential and commercial customers.

In NCSEA's reply comments it contends that increasing the nonprofit rebate will not result in higher nonprofit participation. Rather, NCSEA contends that the lack of participation is attributable to

> a different purchasing cycle. While a homeowner or a commercial facility manager may be able to quickly make a decision about whether to install solar on a residence

> or a business, a nonprofit that is governed by a volunteer board of directors takes significantly more time. Similarly, government agencies, which are eligible for the nonprofit rebate, need to comply with various procurement requirements.

NCSEA Reply Comments at 4. NCSEA continues that while it conceptually supports increasing the nonprofit rebate amount, "it is not willing to do so to the detriment of residential and commercial customers." *Id.* at 5. Notably, NCSEA calculates that under the Public Staff's proposal an 8 kW residential solar installation would receive a rebate of approximately $4,000, whereas under its first proposal to modify the maximum capacity eligible for incentives the same residential solar installation would receive a rebate of $3,000, or $2,400 under its second proposal. *Id.* at 5-6.

Further, NCSEA notes that the federal Solar Investment Tax Credit (ITC) is slated to end for residential systems in 2022 and decline to 10% for commercial and utility scale systems. NCSEA argues that reducing the rebate amounts for customers with tax liabilities right before the ITC expires without allowing for additional customers to participate will "weaken the market for residential and commercial clean energy right when the market will be recovering from our current economic downturn and also dealing with the expiration of the ITC." *Id.* at 6.

Also, NCSEA counters the Public Staff's justification for reducing the residential and commercial rebates, that solar installation costs are decreasing both nationally and in North Carolina, by noting that the same study cited by the Public Staff also found that "the price of residential solar in North Carolina remains more expensive than in other states, in no small part due to regulatory uncertainty leading to slower consumer adoption than in neighboring states such as South Carolina." *Id.* at 6.

Finally, NCSEA opposes the Public Staff's proposals to further reduce rebates by any increase in administrative costs and marketing expenses. NCSEA contends that reducing rebates by estimated costs will cause the rebates to be unclear and difficult to calculate, presenting problems for both solar installers and customers, and will result in "an unacceptable amount of regulatory uncertainty." *Id.* at 8.

In SACE's reply comments it expresses concern that altering the rebates is not "well matched to the availability issues that the rebate program has experienced." SACE Reply Comments at 2. SACE opines that a lower rebate amount likely would not be sufficient for many customers. SACE distinguishes between the Public Staff's proposal to reduce residential and for-profit nonresidential rebates and NCSEA's proposals, which would also effectively reduce the size of the rebates that would be received by these customers. SACE opines that "whereas NCSEA's proposal would increase installations by effectively doubling the number of rebates available for these customers, the Public Staff's proposal would at best keep these installations constant while simply reducing the amount of the rebate each receives." *Id.* at 2. SACE states that it strongly supports increasing funding for nonprofit customers to install solar but prefers that it be accomplished without reallocating rebate funding from other customer classes. SACE also contends, "[t]here is insufficient information at this time to tell whether the Public Staff's proposal is the best solution, because it is not clear at this point whether the rebate level is the main barrier to nonprofit enrollment." *Id.* at 2. Rather, SACE suggests that "nonprofits' relatively long sales cycle" may be responsible for low participation in the nonprofit sector.

ELECTRIC – MISCELLANEOUS

ADDITIONAL PROPOSALS

In its 2019 Annual Report, Duke states that it intends

> to continue to keep the 90-day window for both launch dates. The projects completed within 90 days of the launch date would be eligible to apply. The time frames for completion would be December 31 for residential customers who obtain a reservation in January and June 30 for residential customers who obtain a reservation in July. Non-Residential customers would still have 365 days from the date of the executed interconnection agreement, unless they had a project under 20 kW-AC. In those cases, non-residential customers with a project under 20 kW-AC would continue to have 365 days from the date the rebate reservation was obtained.

2019 Annual Report at 8-9. In response, the Public Staff states that "the current 90-Day Rule in the Solar Rebate Program, which requires a customer to apply no later than 90 days following the installation of a qualifying solar PV system, provides a sufficient timeframe for those customers seeking to apply for the available capacity in the next enrollment window." Public Staff Reply Comments at 9. NCSEA supports Duke's proposal to retain the 90-day eligibility window for systems installed before a rebate application is made.

Duke also proposes to increase its marketing to nonprofits, including city governments, with the goal of increasing nonprofit participation in the program. In response, the Public Staff argues that "[t]o the extent that this increased marketing activity increases Program costs for marketing, this increase should be used to reduce the Public Staff's proposed non-profit rebate . . . in order to maintain revenue-neutrality." Public Staff Initial Comments at 3-4.

In its initial comments NCSEA proposes that

> given the ongoing uncertainty of stay-at-home orders due to COVID-19, the economic impacts of the pandemic, and the potential for a second wave of the pandemic in the fall or winter, . . . the first such biannual application period should open in October 2020. Advancing the opening of the 2021 application period would provide certainty to customers applying for the rebate, and potentially address Duke's concern regarding customers applying for rebates after installing rooftop solar; advancing the opening would also provide business certainty for rooftop solar installers.

NCSEA Initial Comments at 8-9.

Finally, NCSEA requests that Duke file the results of its application process "stress-test" with the Commission. Duke notes that if "the Commission adopts a lottery, the stress-test is no longer necessary because the 'stress' is caused by the rush of a first- come, first served process." Duke Reply Comments at 6. However, if the Commission does not adopt a lottery system, then Duke states that, if necessary, it agrees to provide the results of the stress test.

DISCUSSION AND CONCLUSIONS

The objective of the legislative solar rebate program is to provide an economic incentive for residential, commercial, and nonprofit customers to adopt solar power by reducing the upfront cost of installing solar equipment. The program has proven to be extremely popular, and the demand for rebates greatly exceeds the limited supply — the rebates annually available to residential and for-profit nonresidential customers are fully subscribed within minutes. As NCSEA notes, however, because so few solar customers are guaranteed a rebate, the ratepayer financed program does not appear to be fulfilling its purpose of driving the adoption of solar.

Based upon the forgoing, the Commission agrees that modifications to the program are necessary to provide more customers the opportunity to participate. Thus, as detailed below, the Commission will explore revising the existing incentives to better accomplish the program's goal of creating a program that will offer "reasonable incentives to residential and nonresidential customers for the installation of small customer owned or leased solar energy facilities participating in a public utility's net metering tariff." N.C.G.S. § 62-155(f). Any actions taken by the Commission to revise the program, however, must comport with the mandates of N.C.G.S. § 62-155(f). Lastly, the Commission is cognizant of the fact that with the 90-day eligibility window some customers may be signing contracts and installing systems with the expectation that the current rebate amounts and structure will be in place for the upcoming January 2021 application period.

Additional Annual Application Window

First, the Commission will allow Duke's request to open the 2021 and 2022 solar rebate programs for applications twice each year, in January and July. As Duke notes, splitting the capacity into two windows will (1) reduce the wait time for customers whose applications are not accepted, hopefully reducing customer frustration, and (2) assist installers and developers by spreading their sales over a greater portion of the year. Furthermore, creating a second window for applications in 2021 will enable the Commission to consider and potentially make additional modifications, consistent with the directives outlined herein, to the incentives mid-year.

Regarding the specific date for opening the application window, Duke suggests the fifth business day of the year. Rather than open the window on a Friday, which would be the fifth business day of January 2021, the Commission is of the opinion that a mid-week date would be more appropriate and convenient for customers. The Commission, therefore, finds that it is reasonable to require Duke to open future application windows on Wednesday, January 6, 2021, Wednesday, July 7, 2021, Wednesday, January 5, 2022, and Wednesday, July 6, 2022. As noted above, the parties' comments indicate that some customers are presently making decisions based on the current structure of the program. Thus, the Commission declines to open a window for 2021 rebate applications before January 2021 as NCSEA proposes.

The Commission finds reasonable Duke's recommendation that half of the available annual capacity each year be offered in January and half in July. The Commission further agrees that the current 90-day rule — that a customer must complete and submit a rebate application no later than 90 days following installation of the system — should be applicable to the remaining application windows discussed herein.

Lastly, the Commission expects Duke to perform the necessary technical fixes and testing to avoid a repeat of the technical difficulties experienced by customers applying for rebates in January 2020 and will require Duke to file the results its "stress test" with Commission.

Lottery System to Allocate Residential and Commercial Rebates

While the Commission appreciates Duke's and the Public Staff's willingness to work together to implement a lottery system, the Commission is not persuaded that the administrative time and cost of doing so are justified for the final two years of the program. Moreover, with Duke's commitment to implementing system improvements and the creation of an additional application window each year, the move to a lottery is not necessary to alleviate the "stress" on the system caused by the annual rush to apply for the rebates. The Commission also finds compelling NCSEA's representation that its member solar installers are universally opposed to a lottery and its argument that moving to a lottery system will not drive customer participation or increase rooftop solar adoption. Under the current program customers know immediately whether their rebate application is successful.

Maximum Capacity Eligible for Incentives

Regarding NCSEA's assessment that the solar rebate program is no longer incenting customers to adopt rooftop solar because not enough customers are able to participate, the Commission is not persuaded that NCSEA's proposals to modify the program to address this issue — either reducing by half the maximum size of the systems eligible for a rebate or using a "1:1 ratio for rebate-eligible and rebate ineligible solar" — are authorized by the statute. The Commission agrees with the Public Staff that the plain language of the statute limiting the incentive to 10 kW for residential customer installations and 100 kW for nonresidential customer installations prohibits the Commission from adopting a limit on incentive eligibility that is less than the capacity amounts set forth in the statute. The General Assembly determined the appropriate size of facilities to incentivize for residential and nonresidential customers, and the Commission declines to substitute its judgement for that of the legislature. The Commission, therefore, declines to implement either recommendation proposed by NCSEA.

Adjust Rebate Amounts

Consistent with the parties' comments that to the extent customers' decisions to install solar systems are driven by the availability of rebates, the Commission is persuaded that for the application window opening on Wednesday, January 6, 2021, the incentives should remain at their 2020 levels. Although the parties are divided on whether to adjust the rebate amounts, the Commission finds persuasive the Public Staff's observation that solar installation costs are dropping and further notes that rebates, which are funded by ratepayers, should reflect true and reasonable costs. As such, the Commission will give due consideration to the Public Staff's recommendation to adjust rebate amounts in the future.

The Commission, therefore, finds good cause to solicit comments recommending revised rebate amounts for residential, commercial, and nonprofit customers for consideration to be effective for the application window opening on Wednesday, July 7, 2021. The Commission is not satisfied that it has sufficient proposals before it to modify the existing program to ensure that it functions as intended while still complying with the incentive eligibility constraints set by the General Assembly. Noting that the statute describes the solar rebate program as "offering reasonable incentives to residential and nonresidential customers for the installation of *small* customer owned or leased solar energy facilities participating in a public utility's net metering tariff," N.C.G.S. § 62-155(f) (emphasis added), the Commission is particularly interested in the viability of a tiered system aimed at incentivizing smaller solar installations with a declining incentive structure up to 10 kW for residential customer installations and 100 kW for nonresidential customer installations. One way to better utilize the rebates to encourage solar installations may be to target smaller systems, which are more likely to be installed by customers with greater budget constraints and, therefore, in greater need of an incentive. Further, a tiered system recognizes that the cost of solar installation per watt goes down as the size increases. While the Commission is particularly interested in the viability and structure of a tiered system, other proposals will be considered and fully evaluated. To assist in this effort, the Commission directs Duke to include in its comments responsive to this Order information detailing the characteristics of the residential, commercial, and nonprofit installations receiving rebates, including but not limited to the distribution and average capacity of applications and installations for each customer group. Further, Duke shall include this same information in future annual program reports.

Although the Commission is not proposing herein to increase the rebate amount for non-profit customer installations, the Commission is interested in seeing increased enrollment in the nonprofit program and agrees that Duke should increase its marketing to nonprofits, including city governments, with the goal of increasing nonprofit participation in the remaining years of the program.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke's motion to open the solar rebate program for applications in 2021 and 2022 twice a year, in January and July, shall be granted as modified by the requirements of this Order and subject to the conditions provided herein;

2. That in 2021 the application periods shall open on Wednesday, January 6, 2021, and Wednesday, July 7, 2021;

3. That in 2022 the application periods shall open on Wednesday, January 5, 2022, and Wednesday, July 6, 2022;

4. That 50% of the available annual capacity each year in 2021 and 2022 shall be offered in January and 50% of the available annual capacity shall be offered in July;

5. That Duke shall continue the 90-day eligibility window for systems installed prior to submitting an application for a rebate;

6. That Duke shall conduct and file the results of the application program "stress test" with Commission on or prior to Friday, December 4, 2020;

7. That the current incentive amounts of $0.60 per watt for residential customer installations, $0.50 per watt for commercial customer installations, and $0.75 per watt for nonprofit customer installations shall be effective for the application window beginning on Wednesday, January 6, 2021;

8. That Duke shall increase its marketing to nonprofit customers, including city governments, with the goal of increasing nonprofit participation in the program;

9. That on or before December 1, 2020, all parties may file initial comments addressing appropriate modifications to the current incentive amounts as directed by this Order, including a tiered rebate program as discussed herein;

10. That Duke shall include in its initial comments and in its future annual program reports detailed information regarding the characteristics of residential, commercial, and nonprofit installations receiving rebates, including but not limited to the distribution and average capacity of applications and installations for each customer group;

11. That on or before December 15, 2020, all parties may file reply comments responding to the initial comments filed by other parties; and

12. That upon receipt of the parties' comments, the Commission will proceed as appropriate in establishing rebates for the remainder of the program.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of November, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner ToNola D. Brown-Bland did not participate in this decision.

DOCKET NO. E-2, SUB 1167
DOCKET NO. E-7, SUB 1166

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, for Approval of Solar Rebate Program Pursuant to N.C. Gen. Stat. § 62-155(f)	)))))	ORDER ALLOWING OCTOBER 6 AND 7, 2020 INSTALLATIONS TO APPLY TO SOLAR REBATE PROGRAM BEGINNING ON JANUARY 6, 2021

BY THE COMMISSION: On November 6, 2020, the Commission issued an Order Modifying the Fourth Year of Solar Rebate Program and Requesting Additional Comments (Order) in Docket Nos. E-2, Sub 1167 and E-7, Sub 1166. In pertinent part, the Commission ordered that the first application period of 2021 shall open on Wednesday, January 6, 2021. The Commission also ordered Duke to continue the 90- day eligibility window for systems installed prior to submitting an application for a rebate, meaning that projects completed within 90 days of the start of the enrollment period are eligible to apply for a rebate.

On November 13, 2020, Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC (collectively, Duke or the Companies), filed a Motion for Clarification or Reconsideration (Motion). The Motion states that:

> 1. Pursuant to the Order, the 90-day eligibility period began on October 8, 2020;
>
> 2. Prior to the Order, the 2021 application period was scheduled to open on the first business day of January 2021 (January 4, 2021), which would have resulted in the 90-day eligibility period beginning on October 6, 2020;
>
> 3. On October 6, 2020 and October 7, 2020, at least sixty-three customers had systems installed, presumably in anticipation of applying within the 90-day eligibility period for a solar rebate on January 4, 2021;
>
> 4. Without further Commission action, customers who installed systems on October 6, 2020 and October 7, 2020 will be ineligible to apply for a solar rebate on January 6, 2021; and
>
> 5. The Companies agree with the Commission that a mid-week date for the launch is appropriate because it provides two business days to help customers before and after the opening of the application window.
>
> However, the Companies do not thiuk customers who installed systems on October 6, 2020 and October 7, 2020 in anticipation of applying for a rebate on January 4, 2021 should be disadvantaged by the change in schedule.

Duke requests that "the Commission allow the Companies to accept customers' applications for solar rebates who installed systems on October 6, 2020 and October 7, 2020 that would otherwise be eligible for a solar rebate had the opening window not been moved forward two days from January 4, 2021 to January 6, 2021." No party has objected to Duke's request.

DISCUSSION AND CONCLUSIONS

Pursuant to N.C. Gen. Stat. § 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 herein provided for original orders or decisions.

The Commission's decision to rescind, alter, or amend an order upon reconsideration under N.C.G.S. § 62-80 is within the Commission's discretion. *State ex rel. Utils. Comm'n v. MCI Telecomms. 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. Utils. Comm'n v. N.C. Gas Serv.*, 128 N.C. App. 288, 293-94, 494 S.E.2d 621, 626, rev. denied, 348 N.C. 78, 505 S.E.2d 886 (1998).

The Commission agrees with Duke's calculations of the various scenarios of the enrollment window opening and the corresponding impact on the start date of the 90-day eligibility period. The Commission notes that had the Commission accepted Duke's proposal to open the enrollment period on Friday, January 8, 2021, that installations occurring on October 6, 2020, and October 7, 2020, would have also been similarly ineligible for a rebate as they are now pursuant to the Order. Further, the Commission is cognizant that enrollment for residential and commercial rebates is highly competitive and has considered that adding an additional two days of installations may further contribute to the overdemand the Order attempted to mitigate by adding the second annual enrollment window. However, the Commission continues to give weight to the commentary that, at the time it issued the Order, customers were making decisions based on the structure of 2020 program. While the people and businesses who installed on October 6, 2020, and October 7, 2020, did so without the guarantee of a rebate, they did so with the expectation of having an opportunity to apply. Based upon the foregoing and the entire record herein, the Commission is persuaded by Duke's motion and agrees that customers who installed systems on October 6, 2020, and October 7, 2020, in anticipation of applying for a rebate on January 4, 2021, should not be disadvantaged by the Commission's decision to modify the January 2021 enrollment opening date. Therefore, the Commission finds good cause to modify its prior decision.

IT IS, THEREFORE, ORDERED as follows:

1. That customers who installed systems on October 6, 2020, and October 7, 2020, shall be eligible to enroll in the solar rebate program commencing on Wednesday, January 6, 2021;

2. That nothing herein shall be construed to otherwise alter the 90-day eligibility window approved for the remaining enrollment periods; and

3. That Duke shall file revised compliance tariffs consistent with the provisions of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of November, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-22, SUB 562
DOCKET NO. E-22, SUB 566

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 562 In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina DOCKET NO. E-22, SUB 566 In the Matter of Petition of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for an Accounting Order to Defer Certain Capital and Operating Costs Associated with Greensville County Combined Cycle Addition	)	ORDER ACCEPTING PUBLIC STAFF STIPULATION IN PART, ACCEPTING CIGFUR STIPULATION, DECIDING CONTESTED ISSUES, AND GRANTING PARTIAL RATE INCREASE

HEARD: Tuesday, July 30, 2019, at 7:00 p.m., Halifax County Historical Courthouse, 10 N. King Street, Commissioners' Meeting Room, Halifax, North Carolina

Wednesday, July 31, 2019, at 7:00 p.m., Martin County Courthouse, 305 E. Main Street, Williamston, North Carolina

Wednesday, August 7, 2019, at 7:00 p.m., Dare County Courthouse, 962 Marshall Collins Drive, Manteo, North Carolina

Monday, September 23, 2019, at 2:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chair Charlotte A. Mitchell, Presiding; Commissioners ToNola D. Brown-Bland, Lyons Gray, and Daniel G. Clodfelter

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

APPEARANCES:

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

Mary Lynne Grigg, Andrea R. Kells, and W. Dixon Snukals, McGuireWoods LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 East Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For Carolina Industrial Group for Fair Utility Rates I:

Warren K. Hicks, Bailey & Dixon, LLP, Post Office Box 1351, Raleigh, North Carolina 27602-1351

For Nucor Steel–Hertford:

Joseph W. Eason, Nelson, Mullins, Riley & Scarborough, LLP, 4140 Park Lake Avenue, Suite 200, Raleigh, North Carolina 27612

Damon E. Xenopoulos, Stone Mattheis Xenopoulos & Brew, PC, 1025 Thomas Jefferson Street, NW, Washington, D.C. 20007-5201

For the Attorney General's Office:

Jennifer Harrod, Special Deputy Attorney General, Theresa Townsend, Special Deputy Attorney General, and Margaret A. Force, Assistant Attorney General, North Carolina Attorney General's Office, Department of Justice, 114 West Edenton Street, Raleigh, North Carolina 27603

For the Using and Consuming Public:

David Drooz, Chief Counsel, Dianna Downey, Staff Attorney, Gina Holt, Staff Attorney, Lucy Edmondson, Staff Attorney, Heather Fennell, Staff Attorney, and Layla Cummings, Staff Attorney, North Carolina Utilities Commission – Staff, Legal Division, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On February 27, 2019, pursuant to Commission Rule R1-17(a), Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC or the Company) filed a Notice of Intent to File General Rate Application in Docket No. E-22, Sub 562.

On March 1, 2019, Carolina Industrial Group for Fair Utility Rates I (CIGFUR) filed a Petition to Intervene. The Petition was granted by the Commission on March 7, 2019.

On March 25, 2019, Nucor Steel–Hertford (Nucor) filed a Petition to Intervene. The Petition was granted by the Commission on March 29, 2019.

On March 29, 2019, DENC filed an Application for a general rate increase pursuant to N.C. Gen. Stat. §§ 62-133 and 62-134 and Commission Rule R1-17 (Application) along with a Rate Case Information Report – Commission Form E-1 (Form E-1) and the direct testimony and exhibits of Mark D. Mitchell – Vice President, Generation Construction; Richard M. Davis – Director of Corporate Finance and Assistant Treasurer; Robert B. Hevert – Managing Partner at ScottMadden, Inc.; Bruce E. Petrie – Manager of Generation System Planning; Jason E. Williams – Director of Environmental Services; Paul M. McLeod – Regulatory Specialist; Robert E. Miller – Regulatory Analyst; Paul B. Haynes – Director of Regulation; and Bobby E. McGuire – Director of Electric Transmission Project Development & Execution. Also on March 29, 2019, DENC filed an application for an accounting order to defer certain capital and operating costs associated with its Greensville County Power Station (Greensville CC) in Docket No. E-22, Sub 566. The Company also requested that the Commission consolidate its consideration of the deferral application with the Company's application for a general rate increase in Docket No. E-22, Sub 562.

On April 29, 2019, the Commission issued an Order Declaring General Rate Case and Suspending Rates.

On May 2, 2019, the Commission issued an Order Consolidating Dockets, which consolidated this general rate case with DENC's pending petition for deferral accounting authority to defer post-in-service costs associated with commercial operation of the Greensville County CC in Docket No. E-22, Sub 566.

On May 30, 2019, the Commission issued an Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Deadlines, and Requiring Public Notice.

On August 5, 2019, DENC filed supplemental direct testimony and exhibits of witnesses Davis, McLeod, Miller, Haynes, Petrie, and Deanna R. Kesler – Regulatory Consultant in Demand-Side Planning, as well as applicable supplemental Form E-1 information report items and supplemental Commission Rule R1-17 information.

On August 14, 2019, DENC filed additional supplemental direct testimony and exhibits of witness Haynes.

On August 15, 2019, DENC filed affidavits of publication evidencing proof of publication of notice.

On August 23, 2019, the North Carolina Utilities Commission – Public Staff (Public Staff) filed the testimony and exhibits of Sonja R. Johnson – Accountant; David M. Williamson – Utilities Engineer; Jack L. Floyd – Utilities Engineer; Michelle M. Boswell – Staff Accountant; Tommy C. Williamson – Utilities Engineer; Roxie McCullar – Consultant at William Dunkel and

Associates; Dr. J. Randall Woolridge – Consultant; Jeffrey T. Thomas – Utilities Engineer; Michael C. Maness – Director of the Accounting Division; and Jay B. Lucas – Utilities Engineer. Also on August 23, 2019, Nucor filed the testimony and exhibits of Paul J. Wielgus and Jacob M. Thomas, and CIGFUR filed the testimony and exhibits of Nicholas Phillips, Jr.

On August 27, 2019, the North Carolina Attorney General's Office (AGO) filed a Notice of Intervention.

On August 28, 2019, the Commission issued an Order Requesting Additional Information.

On September 12, 2019, DENC filed second supplemental direct testimony and exhibits of witness McLeod, supplemental Form E-1 items, and supplemental Commission Rule R1-17 information. Also on September 12, 2019, DENC filed the rebuttal testimony and exhibits of witnesses Davis, Hevert, McLeod, Miller, Haynes, and Williams.

On September 16, 2019, the Commission issued an Order Providing Notice of Commission Questions. Also on September 16, 2019, DENC filed its Witness List.

On September 17, 2019, DENC filed an Agreement and Stipulation of Partial Settlement with the Public Staff (Public Staff Stipulation). Also on September 17, 2019, the Public Staff filed Partial Settlement Joint Testimony of witnesses Johnson and James S. McLawhorn – Director, Electric Division, and DENC filed testimony of witnesses Davis, Hevert, McLeod, Miller, and Haynes in support of the Public Staff Stipulation.

On September 18, 2019, the Public Staff filed supplemental testimony of witness Maness. Also on September 18, 2019, the Public Staff filed exhibits and supporting schedules for the joint testimony of witnesses McLawhorn and Johnson previously filed on September 17, 2019.

On September 19, 2019, DENC and the Public Staff filed a joint motion to excuse several of their witnesses, and CIGFUR filed a motion to excuse its witness. The motions were granted on September 23, 2019.

On September 23, 2019, DENC filed an Agreement and Stipulation of Settlement with CIGFUR (CIGFUR Stipulation). Also on September 23, 2019, DENC filed a Revised Witness List and Late Filed Exhibits in response to the Commission's Order Providing Notice of Commission Questions.

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

Halifax: Tony Burnette, Dean Knight, Chuck Overton, and Silverleen Alston.

Williamston: John Liddick, Patrick Flynn, Tommy Bowen, James Wiggins, and Glenda Barnes.

Manteo: Rhett White, Manny Medeiros, John Windley, and Brad Bernard.

Raleigh: No public witnesses appeared.

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

The matter came on for expert witness hearing on September 23, 2019. DENC presented the testimony of witnesses Mitchell, Davis, Hevert, McLeod, Haynes, Miller, and Williams. The testimony and exhibits of DENC witnesses McGuire, Kessler, and Petrie were stipulated into the record. The testimony and exhibits of Nucor witnesses Thomas and Wielgus were stipulated into the record. The testimony and exhibits of CIGFUR witness Phillips were stipulated into the record. The Public Staff presented the testimony of witnesses Maness, Johnson, and McLawhorn. The testimony and exhibits of Public Staff witnesses David Williamson, Floyd, Boswell, Tommy Williamson, McCullar, Woolridge, and Thomas were stipulated into the record.

The pre-filed testimony of those witnesses who testified at the expert witness hearing, as well as the pre-filed testimony of all other witnesses filing testimony in this docket, was copied into the record as if given orally from the stand, and their pre-filed exhibits were admitted into evidence.

The Public Staff and DENC filed late-filed exhibits and responses to Commission questions on September 23, September 26, September 27, October 1, October 2, October 7, October 8, and October 23, 2019.

On November 6, 2019, DENC and the Public Staff filed a Joint Proposed Order on the issues covered by the Public Staff Stipulation and separate proposed orders on the issues of cost recovery for coal combustion residuals. Post-hearing briefs were filed by DENC, the AGO, CIGFUR, and Nucor.

The above is a summary of the main filings and proceedings in this docket. Additional filings made by the parties and orders issued in this proceeding are not discussed in this Order but are included in the record.

Based on the entire record in this proceeding, the Commission makes the following

FINDINGS OF FACT

Jurisdiction

1. Virginia Electric and Power Company (VEPCO) is duly organized as a public utility operating under the laws of the State of North Carolina as Dominion Energy North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. DENC is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the

public in North Carolina for compensation. DENC is an unincorporated division of VEPCO and has its office and principal place of business in Richmond, Virginia. VEPCO is a wholly-owned subsidiary of Dominion Energy, Inc. (DEI).

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

3. DENC is lawfully before the Commission based upon its application for a general increase in its retail rates pursuant to N.C.G.S. §§ 62-133, 62-133.2, 62-134, and 62-135, and Commission Rule R1-17.

4. The appropriate test period for use in this proceeding is the 12 months ended December 31, 2018, adjusted for certain known changes in revenue, expenses, and rate base.

The Application

5. In summary, by its general rate case Application, supporting testimony, and exhibits filed on March 29, 2019, and on subsequent dates during the proceeding, DENC sought an increase in its non-fuel base rates and charges to its North Carolina retail customers of $26,958,000, along with other relief, including cost deferrals and changes to its rate design. The Application was based upon a requested rate of return on common equity of 10.75%, an embedded long-term debt cost of 4.451%, and DENC's actual capital structure of 53.01% common equity and 46.99% long-term debt, as of December 31, 2018. DENC submitted supplemental filings and testimony after its initial Application and the effect of the Company's supplemental filings was to change its proposed annual base non-fuel revenue requirement to a $24,195,000 increase in annual revenue.

Stipulation with Public Staff

6. On September 17, 2019, DENC and the Public Staff (Stipulating Parties) entered into and filed the Public Staff Stipulation, resolving all of the issues in this proceeding among the Stipulating Parties, except for issues associated with coal combustion residuals (CCR) costs.

7. The Public Staff Stipulation is the product of give-and-take in settlement negotiations between the Stipulating Parties, and it is material evidence entitled to be given appropriate weight by the Commission.

Stipulation with CIGFUR

8. On September 23, 2019, DENC and CIGFUR entered into and filed the CIGFUR Stipulation, resolving rate of return and certain cost allocation, rate design, and terms and conditions issues in this proceeding.

9. The CIGFUR Stipulation is the product of give-and-take in settlement negotiations between DENC and CIGFUR, and it is material evidence entitled to be given appropriate weight by the Commission.

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

10. The capital structure set forth in Section III.A of the Public Staff Stipulation, consisting of 52.00% common equity and 48.00% long-term debt, is reasonable and appropriate for use by DENC in this case.

11. The embedded cost of debt set forth in Section III.A of the Public Staff Stipulation of 4.442% is reasonable and appropriate for use by DENC in this case.

12. The rate of return on common equity that the Company should be allowed the opportunity to earn in this docket is 9.75%, as set forth in Section III.A of the Public Staff Stipulation and is reasonable and appropriate for use in this docket.

13. The overall rate of return that the Company should be allowed the opportunity to earn on the cost of the Company's used and useful property is 7.20%, as set forth in Section III.A of the Public Staff Stipulation and is reasonable and appropriate for use in this docket.

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

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

a. The overall rate of return on rate base and allowed rate of return on common equity underlying DENC's current base rates are 7.367% and 9.90%, respectively.[1]

b. DENC's current base rates became effective for service rendered on and after January 1, 2017, and have been in effect since that date.

c. In its Application, DENC sought approval for rates which were based on an overall rate of return on rate base of 7.79% and an allowed rate of return on common equity of 10.75%.

[1] Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, *Application by Virginia Electric and Power Co., d/b/a Dominion North Carolina Power for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-22, Sub 532 (N.C.U.C. Dec. 22, 2016) (DENC Sub 532 Order).

d. As set forth in the Public Staff Stipulation, the Stipulating Parties seek approval of an overall rate of return on rate base of 7.20% and an allowed rate of return on common equity of 9.75%.

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

f. As reported by Regulatory Research Associates (RRA), the median rate of return on equity authorized for vertically integrated electric utilities during the first half of 2019 was 9.73% (compared to 9.75% in 2018). The authorized rate of return on equity for vertically integrated electric utilities is in the top third of all jurisdictions rated by RRA in terms of constructive, and less risky regulatory environments range from 9.37% to 10.55%, with a mean of 9.93% and a median of 9.95% from 2016 through early September of 2019.

g. The stipulated rate of return on common equity of 9.75% is equal to the lowest rate of return on common equity granted by the Commission for a major electric utility in the last ten years.

h. The currently authorized rate of return on common equity underlying the base rates of Public Service Company of North Carolina, Inc. (PSNC), and Piedmont Natural Gas Company, Inc. (Piedmont), is 9.70%.[1] The currently authorized rate of return on common equity for Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP), is 9.90%.[2]

i. The stipulated allowed rate of return on common equity of 9.75% is consistent with the rates of return on common equity identified above.

j. The stipulated overall rate of return on rate base of 7.20% and rate of return on common equity of 9.75% are supported by competent, material, and substantial evidence.

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[1] Order Approving Rate Increase and Integrity Management Tracker, *Application of Public Service Co. of North Carolina, Inc., for a General Increase in its Rates and Charges*, No. G-5, Sub 565 (N.C.U.C. Oct. 28, 2016) (PSNC Sub 565 Order); Order Approving Stipulation, Granting Partial Rate Increase, Line 434 Revenue Rider, EDIT Riders, Provisional Revenues Rider, and Requiring Customer Notice, *Application of Piedmont Natural Gas Co., Inc., for an Adjustment of Rates, Charges, and Tariffs Applicable to Service in North Carolina, Continuation of its IMR Mechanism, Adoption of an EDIT Rider, and Other Relief*, No. G-9, Sub 743 (N.C.U.C. Oct. 31, 2019) (PNG Sub 743 Order).

[2] Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, *Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-7, Sub 1146 (N.C.U.C. June 22, 2018), *appeal docketed*, No. 401A18 (N.C. Nov. 7, 2018) (DEC Sub 1146 Order); Order Accepting Stipulations, Deciding Contested Issues and Granting Partial Rate Increase, *Application by Duke Energy Progress, LLC, For Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1142 (N.C.U.C. Feb. 23, 2018), *appeal docketed*, No. 401A18 (N.C. Nov. 7, 2018) (DEP Sub 1142 Order).

k. The evidence indicates that the overall economic climate in North Carolina (and nationally) remains strong, including data and projections from reliable sources that demonstrate: (i) generally consistent with the national rate of unemployment, the rate of unemployment in North Carolina has fallen by 8.30 percentage points since its peak in late 2009 and early 2010 to 3.70% by December 2018; (ii) unemployment in the DENC counties peaked in late 2009 – early 2010 at 13.41% and had fallen to 4.95% by December 2018; growth in the Gross Domestic Product (GDP) is relatively strongly correlated between North Carolina and the national economy, and it has been growing at a moderate pace since 2016; (iii) median household income in North Carolina has grown since 2009 at an annual rate of 2.32%; and (iv) residential electric rates in North Carolina since 2018 remain approximately 13% below the national average.

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

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

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

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

Adjustments to Cost of Service

17. The Public Staff Stipulation provides for certain accounting adjustments, which are set forth in detail at Settlement Exhibit I. The Stipulating Parties agree that the settlement regarding those issues will not be used as a rationale for future arguments on contested issues brought before the Commission. The accounting adjustments outlined in Settlement Exhibit I, except line No. 18 pertaining to Chesterfield Units 3 and 4, are just and reasonable to all parties in light of all the evidence presented.

18. The Company's updates through June 30, 2019, to certain revenues, expenses, and investments, as agreed to and adjusted in the Public Staff Stipulation, are appropriate for use in this proceeding.

19. DENC's pro forma inclusion in rates of the full cost of service of the Greensville combined cycle generating plant (Greensville CC), which began commercial operation on December 8, 2018, is appropriate, with the exception of the non-fuel O&M expenses for displacement adjustment, as discussed below.

20. DENC's request to defer the costs associated with the Greensville CC from the time the unit was placed into service until placement in base rates in this rate case is appropriate. Amortization over a three-year period beginning with the effective date of new rates in this proceeding is also appropriate.

21. The Public Staff Stipulation provides that an adjustment of $81,000 should be made to storm restoration costs to reflect the use of a ten-year historical average of these costs. This provision of the Public Staff Stipulation is just and reasonable to all parties in light of all the evidence presented.

22. The Stipulating Parties have agreed to a reduction in revenue requirement of $142,000 for the variable non-fuel O&M expenses displacement. This agreed upon adjustment is to reflect the updated and corrected purchased energy and electric test year output numbers, and it is just and reasonable to all parties in light of the evidence presented.

23. The Public Staff's adjustment to remove the costs of the Skiffes Creek project mitigation is appropriate as provided for in the Public Staff Stipulation.

24. The Public Staff Stipulation provides that 50% of the Mount Storm impairment costs should be removed, with the remaining portion amortized over 2.75 years. This provision of the Public Staff Stipulation is just and reasonable to all parties in light of all of the evidence presented.

25. The Stipulating Parties have agreed to reduce the revenue requirement by $720,000 to reflect the updated, actual costs of the Company's new office building (DES Office). In light of the evidence presented, this adjustment is just and reasonable to all parties.

26. As set forth in Section IV.S of the Public Staff Stipulation, the Stipulating Parties have agreed that the Company's depreciation rates will be set based on the rates set forth in the Company's Application. Subject to Findings of Fact Nos. 56-58 and the discussion thereunder, this provision of the Public Staff Stipulation is just and reasonable to all parties in light of all of the evidence presented.

Federal Excess Deferred Income Taxes

27. The Company is adjusting rates to pass along to North Carolina jurisdictional customers the benefit of federal excess deferred income taxes (EDIT) resulting from the Federal Tax Cuts and Jobs Act of 2017 (Tax Act). The system-level federal EDIT balance as of December 31, 2017, was $2.0 billion, of which $94.7 million was allocable to the North Carolina retail jurisdiction.

28. The Public Staff Stipulation provides that DENC will implement an increment rider, Rider EDIT, to allow for the recovery by DENC of federal EDIT of $1,214,000 (on a pre-income tax basis). This amount includes all unprotected federal EDIT allocable to the North Carolina jurisdiction totaling approximately $8.0 million, partially offset by the refund to ratepayers of approximately $6.8 million associated with North Carolina jurisdictional federal EDIT amortization attributable to the 22-month period of January 1, 2018, through October 31, 2019.

29. DENC should implement Rider EDIT to recover certain federal EDIT from customers over a two-year period on a levelized basis, with a return. As reflected on Settlement Exhibit II, Schedule 2, the appropriate amount to be recovered from customers is a total of $1,299,369. Rider EDIT should be calculated and reviewed using the methodology presented in the testimony of DENC witness Haynes.

30. The Company's fully-adjusted cost of service includes the income tax benefit arising from the annual amortization of federal protected EDIT during the test year, thereby incorporating a going-level of federal protected EDIT amortization in base non-fuel rates.

31. The ratemaking treatment of federal EDIT, including Rider EDIT as set forth in the Public Staff Stipulation, is just and reasonable to all parties in light of all of the evidence presented.

Base Fuel Factor

32. The Public Staff Stipulation provides for a total decrease in DENC's annual base fuel revenues of $2.155 million from its North Carolina retail electric operations, based on a jurisdictional average base fuel factor of 2.092¢/kWh (including regulatory fee), which is just and reasonable to all parties in light of all the evidence presented.

33. The jurisdictional average base fuel factor should be voltage-differentiated between customer classes, as provided on Company Additional Supplemental Exhibit PBH-1, Schedule 1, Page 2.

34. The Company has proposed to adjust its base fuel and non-fuel expenses to reflect 71% as a proxy for the fuel cost component of energy purchases for which the actual fuel cost is unknown (Marketer Percentage), with the remaining 29% of the cost of energy purchases being recovered by DENC in base rates. This represents a reduction from the Company's current Marketer Percentage of 78%. The 71% Marketer Percentage is reasonable and appropriate for use in this proceeding and shall remain in effect until the Company's 2021 annual fuel factor filing or next general rate case, whichever comes first.

Cost of Service Allocation Methodology

35. The Public Staff and CIGFUR Stipulations provide for the use of the Summer-Winter Peak and Average (SWPA) methodology calculated using the system load factor to weight the average component and (1 – system load factor) to weight the peak demand component to

allocate the Company's cost of service to the North Carolina jurisdiction and among the customer classes in this case. The Stipulating Parties and CIGFUR agree that use of the SWPA methodology for allocation between jurisdictions and among customer classes shall not be a precedent for, and may be contested in, future general rate case proceedings. The Stipulating Parties further agree that the Company's proposed adjustments (1) to DENC's recorded summer and winter peaks to recognize the peak demand contributions of non-utility generators (NUGs) interconnected to the Company's distribution system, and (2) to remove the demand and energy requirements of three customers, one wholesale customer North Carolina Electric Membership Corporation (NCEMC), and two large industrial customers in the Company's Virginia jurisdiction for whom the obligation to provide generation service has ended or will end during 2019 are appropriate and reasonable. The SWPA cost of service methodology, adjusted as described, is appropriate for determining the Company's North Carolina jurisdictional and retail customer class cost allocation and responsibility for purposes of this case.

36. DENC's adjustment to the peak component of SWPA appropriately recognizes the impact that NUGs have on DENC's utility system and is appropriate for use in this proceeding.

37. DENC's adjustment to remove the demand and energy requirements of customers whose service has ended or will end during 2019 is appropriate for use in this proceeding.

38. The SWPA cost of service methodology, as adjusted by DENC, has been used in this Order to determine the appropriate levels of rate base, revenues, and expenses for North Carolina retail service.

39. DENC's continued use of the SWPA methodology in this proceeding properly assigns production plant costs to all customer classes, including the Schedule NS Class, in recognition of its significant use of the Company's generation throughout the year.

Rate Design

40. For purposes of apportioning and assigning the approved increase in base non-fuel and base fuel revenues between the North Carolina customer classes in this proceeding, the apportionment should be consistent with the principles described in the testimony of Public Staff witness Floyd and the rate design presented by Company witness Haynes in his direct testimony, as adjusted by and as referenced in Section VI of the Public Staff Stipulation, which are reasonable, appropriate, and nondiscriminatory. The Public Staff Stipulation further provides that in developing rates based upon the foregoing class apportionment, the Company should consider the rate of return indices for the LGS and 6VP classes and an appropriate rate of return index for the Schedule NS class. Finally, the Public Staff Stipulation provides that all classes should share in the total base revenue increase. The rate design principles proposed by the Company, as filed revised by the Public Staff Stipulation, are just and reasonable.

Service Regulations, Vegetation Management, and Quality of Service

41. The amendments to the service regulations proposed by the Company are reasonable.

42. The vegetation management plan of the Company is reasonable.

43. The overall quality of service provided by DENC is good.

Conversion Costs of Chesterfield Power Station Units 3 and 4

44. The resolution of the recovery of the CCR wet to dry CCR handling conversion costs incurred by DENC at the Chesterfield Power Station (Chesterfield) Units 3 and 4, as set forth in Section VII.A of the Public Staff Stipulation, is not approved.

45. DENC's decision to incur wet to dry CCR handling conversion costs for Chesterfield Units 3 and 4 was not reasonable and prudent.

46. DENC should not be allowed to recover from North Carolina retail ratepayers the jurisdictional costs arising from the wet to dry CCR conversion project for Units 3 and 4 at Chesterfield.

Acceptance of Stipulations

47. Based upon all of the evidence in the record, including consideration of the public witness testimony and the evidence from parties who have not agreed with the Public Staff and CIGFUR Stipulations, with the exception of Section VII.A of the Public Staff Stipulation and subject to in Findings of Fact Nos. 56-58 and the discussion thereunder relating to the costs of removal portion of depreciation allowance, the provisions of the Stipulations are just and reasonable to the customers of DENC and to all parties to this proceeding, and serve the public interest. Therefore, the Stipulations should be approved in their entirety, with the exception of Section VII.A of the Public Staff Stipulation and subject to the Findings of Fact Nos. 56-58 and the discussion thereunder relating to the costs of removal portion of depreciation allowance. In addition, the Stipulations are entitled to substantial weight and consideration in the Commission's decision in this docket.

48. The base non-fuel and base fuel revenues provided in and resulting from the Public Staff and CIGFUR Stipulations, with the exception of Section VII.A of the Public Staff Stipulation, are just and reasonable to the customers of DENC, to DENC, and to all parties to this proceeding, and serve the public interest.

Recovery of CCR Costs

49. Since its last rate case, on a North Carolina retail jurisdictional basis, from the period beginning July 1, 2016 and running through June 30, 2019 (the Deferral Period), DENC

has incurred $21.8 million in costs associated with the management of CCRs (the CCR Costs). The $21.8 million includes: (1) $19.2 million in expenditures made during the Deferral Period to comply with federal and state environmental regulations associated with managing CCRs and converting or closing waste ash management facilities at seven of DENC's generation stations; and (2) $2.7 million in financing costs incurred during the Deferral Period.

50. The record includes substantial evidence that, particularly where CCRs were being managed in lined landfills, the CCR Costs incurred during the Deferral Period were prudently incurred.

51. Although the Public Staff offered evidence challenging the manner in which DENC had managed CCRs and its various CCR waste management facilities over several decades, insofar as the specific CCR Costs incurred during the Deferral Period are concerned, while the record contains evidence that identifies instances of imprudence, the record contains insufficient evidence to permit the Commission to quantify the effects of imprudent actions on ratepayers.

52. DENC is entitled to recover the CCR Costs established in this general rate case, in the manner and subject to the conditions as set forth herein.

Ratemaking Treatment of Recoverable CCR Costs

53. Just and reasonable rates will be achieved by excluding from rate base the CCR Costs and amortizing recovery of the CCR Costs over a period of ten years.

54. It is reasonable, based on the evidence in the record in this proceeding, for DENC to recover its financing costs on the CCR Costs incurred during the Deferral Period, up to the effective date of rates approved pursuant to this Order, calculated at the Company's previously authorized weighted average cost of capital.

55. It is reasonable, based on the evidence in the record in this proceeding for annual compounding to be used in calculating the financing costs of deferred costs, including the CCR Costs, during the Deferral Period.

Accounting for CCR Remediation and Closure Costs

56. DENC did not account for CCR remediation costs as costs of removal in computing and requesting recovery of its allowance for depreciation expense.

57. DENC's failure to incorporate costs of remediation and closure of CCR waste management facilities as part of its allowance for depreciation expense is contrary to accepted depreciation expense accounting principles.

58. It is appropriate to require DENC to properly account for costs of remediation and closure of CCR waste management facilities as part of costs of removal included in its allowable depreciation expense.

CCR Insurance Claims

59. DENC should be required to take reasonable and prudent actions to pursue claims for insurance coverage of CCR remediation costs, where justified by DENC's insurance policy coverage.

60. All insurance proceeds received or recovered by DENC from the existing and potential CCR insurance claims should be placed in a regulatory liability account until the Commission enters an order directing DENC as to the appropriate disbursement of the proceeds. The regulatory liability account should accrue a carrying charge at the net-of-tax overall rate of return authorized for DENC in this Order.

61. Within ten days of the resolution of any of DENC's CCR insurance claims, whether by settlement, judgment or otherwise, DENC should file a report with the Commission explaining the result and stating the amount of insurance proceeds to be received or recovered by DENC. This reporting requirement should apply even if there is litigation that is appealed to a higher court.

62. If meritorious concerns are raised by any party or by the Commission regarding the reasonableness of DENC's efforts to obtain an appropriate amount of recovery from the CCR insurance claims, DENC should bear the burden of proving that it exercised reasonable care and made prudent efforts to obtain the maximum recovery from the insurance claims.

Accounting for Deferred Costs

63. The Company is authorized to receive a specific amount of revenue for each of the deferred costs approved by this Order. If DENC receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company should continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case.

Revenue Requirement

64. After giving effect to the Commission's partial approval of the Public Staff Stipulation and full approval of the CIGFUR Stipulation, and the Commission's decisions on contested issues, the annual revenue requirement for DENC will allow the Company a reasonable opportunity to earn the rate of return on its rate base.

65. As soon as practicable following the issuance of this Order, DENC should calculate and file the annual revenue requirement with the Commission, consistent with the findings and conclusions of this Order. The Company should work with the Public Staff to verify the accuracy of the filing. DENC should file schedules summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and

determinations in this proceeding. DENC should provide the Commission with electronic copies of the filing, complete with formulas intact.

Just and Reasonable Rates

66. The base non-fuel and base fuel revenues and rates approved herein are just and reasonable to the customers of DENC, to DENC, and to all parties to this proceeding, and serve the public interest.

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

The evidence supporting these findings of fact and conclusions is contained in the verified Application and Form E-1 of DENC, the testimony and exhibits of the witnesses, and the entire record in this proceeding. These findings and conclusions are informational, procedural, and jurisdictional in nature, and are not contested by any party. In addition, the Commission finds and concludes that the Company's use of a test period of the 12 months ended December 31, 2018, with appropriate adjustments for certain known changes in revenue, expenses, and rate base, comports with the requirements of N.C.G.S. § 62-133 and Commission Rule R1-17, and is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting this finding of fact and conclusions is contained in the verified Application and Form E-1 of DENC, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Summary of the Evidence

On February 27, 2019, pursuant to Commission Rule R1-17(a), DENC filed notice of its intent to file a general rate case application.

On March 29, 2019, DENC filed its Application and initial direct testimony and exhibits, seeking a net increase of $26,958,000 in its annual base non-fuel rate revenue from its North Carolina retail electric operations. The Application is based on a requested rate of return on common equity of 10.75%, an overall rate of return of 7.79%, an embedded long-term debt cost of 4.451%, and DENC's actual capital structure of 53.01% common equity and 46.99% long-term debt, as of December 31, 2018. Further, the Application states that DENC's 2018 return on equity was 7.52% and its overall rate of return was 6.08%.

The Company's last general rate case was in 2016 in Docket No. E-22, Sub 532 (2016 Rate Case or Sub 532). By Order issued on December 22, 2016, the Commission approved an increase in DENC's base non-fuel revenues of $34,732,000, and a decrease of $8,942,000 in its base fuel revenues. DENC's current authorized rate of return on common equity is 9.9%, its authorized overall rate of return is 7.367%, and its authorized capital structure for ratemaking purposes is 51.75% common equity and 48.25% long-term debt. On March 4, 2019, the Commission approved a base non-fuel revenue reduction of $14,349,000 in Docket No. E-22, Sub 560, due to the net reduction in the Company's revenue requirement (i.e., the income tax expense component in then-current base rates) associated with the reduction in the federal corporate income tax rate pursuant to the Federal Tax Cuts and Jobs Act of 2017.

In its present Application, the Company proposed to implement the non-fuel base rate increase on a temporary basis subject to refund effective on November 1, 2019, along with an accelerated implementation of its new lower base fuel rate – to be filed in August 2019 – as part of any temporary rates (subject to refund) proposed to become effective November 1, 2019. The Company also proposed a methodology for returning certain federal EDIT to customers through a decrement rider, Rider EDIT, over a one–year period. Further, DENC proposed to amortize the post-in-service costs of the Greensville CC it had requested to defer in Docket No. E-22, Sub 566.[1]

In its supplemental testimony filed on August 5, 2019, DENC updated the increase sought in its non-fuel base rates and charges to its North Carolina retail customers to $24.9 million.

In its second supplemental testimony filed on September 12, 2019, DENC updated the increase sought to $24.2 million.

Discussion and Conclusion

The Commission finds and concludes that DENC's Application satisfies the requirements of N.C.G.S. § 62-133, et seq., and Commission Rule R1-17. Further, DENC is a public utility within the meaning of N.C.G.S. § 62-3(23). Therefore, pursuant to N.C.G.S. § 62-30, et seq., the Commission has jurisdiction to consider and decide DENC's Application for a rate increase and other relief.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-7

The evidence supporting these findings of fact and conclusions is contained in the testimony of DENC witnesses Davis, McLeod, Hevert, Miller, and Haynes; Public Staff witnesses McLawhorn and Johnson; and the entire record in this proceeding.

Summary of the Evidence

On September 17, 2019, the Stipulating Parties filed the Public Staff Stipulation resolving all issues except the recovery of the Company's CCR costs. The Public Staff Stipulation is based on the same test period as the Company's Application. In summary, the Public Staff Stipulation provides:

- the revenue requirement increase of $24,879,000 proposed by the Company in its August 5, 2019, supplemental filing should be reduced by at least $13,517,000, based on the Company's position of an increase in the revenue requirement of $6.428 million,

[1] Consolidated into Docket No. E-22, Sub 562 by Commission Order Consolidating Dockets (May 2, 2019).

consisting of an increase of $8.583 million in non-fuel revenues and a decrease of $2.155 million in base fuel revenues, and the Public Staff's position of an increase in the revenue requirement of $2.037 million, consisting of an increase in $4.192 million in non-fuel revenues and a decrease of $2.155 million in base fuel revenues, with the difference between the Company's and the Public Staff's positions resulting from the unresolved issues identified in Section II.A.i of the Public Staff Stipulation (cost recovery of the Company's CCR costs, the recovery amortization period, and return during the amortization period);

- a rate of return on common equity of 9.75% and an overall rate of return on rate base of 7.20%;
- a capital structure for ratemaking purposes consisting of 52% equity and 48% long-term debt;
- an embedded cost of debt of 4.442%;
- agreement on numerous adjustments to the Company's cost of service;
- a $2.155 million decrease in DENC's annual base fuel revenues and a base fuel factor of 2.092¢/kWh, including regulatory fee;
- a decrement Rider A1, equal to (0.375¢/kWh) on a jurisdictional basis, calculated as the difference between the currently approved Rider B Experience Modification Factor (EMF) of 0.388¢/kWh and the proposed Rider B EMF in the Company's 2019 Fuel Case (Docket No. E-22, Sub 579) of 0.013¢/kWh;
- a Rider EDIT allowing for the recovery of $1,214,000 of federal EDIT, which includes the amortization of all unprotected federal EDIT totaling approximately $8.0 million partially offset by the refund of approximately $6.8 million associated with federal EDIT amortization attributable to the 22-month period of January 1, 2018, through October 31, 2019;
- allocation of the Company's cost of service based on the SWPA method, including adjustments to recognize the peak demand contributions of NUGs interconnected to the Company's distribution system and to remove the demand and energy requirements of three customers in DENC's Virginia jurisdiction for whom the obligation to provide generation service has ended or will end during 2019;
- inclusion of certain wet-to-dry conversion costs at the Chesterfield Power Station (Chesterfield) in the revenue requirement, subject to a similar dispute pending in the Company's Virginia jurisdiction; and
- agreement that the overall quality of electric service provided by DENC is good.

In support of the Public Staff Stipulation, Company witness McLeod testified that DENC, the Public Staff, and intervenors engaged in substantial discovery regarding the matters addressed in the Public Staff Stipulation. Witness McLeod further testified that the Public Staff Stipulation is the result of give-and-take negotiations in which each party made substantial compromises on individual issues in order to obtain a compromise from the other parties on other issues. He stated that the Stipulating Parties believe the results reached are fair to the Company and its customers. Witness McLeod also noted that the Public Staff Stipulation resolves all but one contested issue in the case between the Stipulating Parties without the necessity of contentious litigation. With respect to the contested issue not resolved by the Public Staff Stipulation, witness McLeod explained that $4.3 million of the CCR costs would be resolved outside of the Public Staff Stipulation as the Company would not support the "equitable sharing" methodology for these remaining CCR costs. Tr. vol. 4, 334-41.

Company witness Hevert also filed testimony in support of the Public Staff Stipulation. He testified that the 9.75% rate of return on common equity agreed to in the Public Staff Stipulation reflects negotiations among the Stipulating Parties and, taken as a whole with the rest of the Public Staff Stipulation, would be viewed by the financial community as constructive and equitable. Witness Hevert acknowledged that the 9.75% Stipulation rate of return on common equity falls below his recommended range of 10.00% to 11.00% but noted that the stipulated rate of return on common equity is a reasonable resolution of a complex and frequently contentious issue. Tr. vol. 4, 115-19.

Company witness Davis' testified in support of the Public Staff Stipulation's capital structure of 52.00% equity and 48.00% long-term debt. He stated that while differing from the recommendation in his direct testimony, the stipulated capital structure represents a reasonable compromise when considered within the context of the Public Staff Stipulation taken as a whole. Tr. vol. 4, 231-33.

Company witness Miller's testimony in support of the Public Staff Stipulation supported the cost of service issues agreed upon in the Public Staff Stipulation and provided updated schedules with a fully adjusted cost of service study showing the effects of all adjustments and rate changes to the North Carolina classes based on the Public Staff Stipulation. Tr. vol. 4, 538-42.

Finally, DENC witness Haynes' testimony in support of the Public Staff Stipulation explained the cost allocation, revenue apportionment, rate design, and cost of service studies agreed upon in the Public Staff Stipulation. Witness Haynes testified that the Public Staff Stipulation presents a just and reasonable approach to establishing the cost of service for the Company's North Carolina jurisdiction using the SWPA allocation methodology. He also explained that the SWPA methodology used the system load factor to weight the average component and the peak demand component, which was the same approach proposed in the Company's direct and rebuttal testimony, as well as the approach supported by Public Staff witness Floyd. Witness Haynes also explained that the Company still proposed to include decrement Rider A1 to mitigate the effect of the November 1, 2019, base non-fuel increase. Tr. vol. 4, 485-90.

Public Staff witnesses McLawhorn and Johnson filed joint testimony in support of the Public Staff Stipulation. They testified to the Public Staff's perception of several benefits provided by the Public Staff Stipulation, including a reduction in the base non-fuel revenue increase initially requested by DENC and the avoidance of protracted litigation between the Stipulating Parties. Similar to DENC witness McLeod, witnesses McLawhorn and Johnson stated that the CCR costs issue was not resolved in the Public Staff Stipulation and, therefore, the accounting and ratemaking adjustments cannot be finalized until the Commission makes a determination on that issue. Tr. vol. 6, 52.

Discussion and Conclusions

As the Public Staff Stipulation has not been adopted by all of the parties to this docket, the Commission's determination of whether to accept or reject the Public Staff Stipulation is governed by the standards set out by the North Carolina Supreme Court in *State ex rel. Utilities Commission v. Carolina Utility Customers Ass'n, Inc.*, 348 N.C. 452, 500 S.E.2d 693 (1998) (*CUCA I*), and *State ex rel. Utilities Commission v. Carolina Utility Customers Ass'n, Inc.*, 351 N.C. 223, 524 S.E.2d 10 (2000) (*CUCA II*). In *CUCA I*, the Supreme Court held:

> [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 the Court to subject the Commission's Order adopting the provisions of a non-unanimous stipulation to a "heightened standard" of review. 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a non-unanimous 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 DENC witness McLeod regarding the Stipulating Parties' efforts in negotiating the Public Staff Stipulation. Further, the Commission gives significant weight to the settlement testimony of Public Staff witnesses McLawhorn and Johnson, which in their discussion of the benefits that the Public Staff Stipulation will provide to customers and their testimony describing the compromise reflected in the Public Staff Stipulation's terms, indicate the Public Staff's commitment to fully represent the using and consuming public.

As a result, the Commission finds and concludes that the Public Staff Stipulation is the product of the give-and-take between the Stipulating Parties during their settlement negotiations in an effort to appropriately balance DENC's need for increased revenues and its customers' needs to receive safe, adequate, and reliable electric service at the lowest possible rates. In addition, the Commission finds and concludes that the Public Staff Stipulation was entered into by the Stipulating Parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket. As a result, the Public Staff Stipulation is material evidence to be given appropriate weight in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-9

The evidence supporting these findings of fact and conclusions is contained in the testimony of DENC witnesses Davis, Hevert, Miller, and Haynes; CIGFUR witnesses Wielgus and Thomas; and the entire record in this proceeding.

Summary of the Evidence

On September 23, 2019, DENC and CIGFUR (CIGFUR Stipulating Parties) filed the CIGFUR Stipulation resolving certain issues related to rate of return, cost allocation, rate design, and terms and conditions. In summary, the CIGFUR Stipulation provides:

- the Company's SWPA methodology calculated using the system load factor to weight the average component and (1 - system load factor) to weight the peak demand component is appropriate for use in allocating the Company's per books cost of service to the North Carolina jurisdiction and between customer classes in this case;

- DENC and CIGFUR agree to the two adjustments the Company made in the course of calculating the SWPA;

- in the next general rate case, the Company should file the results of a class cost of service study with production and transmission costs allocated on the basis of the Summer/Winter Coincident Peak method in addition to the SWPA used in this proceeding and consider such results for the sole purpose of apportionment of the change in revenue to the customer classes; and

- considering that no customers have taken service under the pilot Real Time Pricing (RTP) rates filed by the Company and approved by the Commission in Sub 532, the Company will work with CIGFUR to consider whether certain provisions within those rates should be modified. If there is mutual agreement between CIGFUR and DENC to such modifications, and CIGFUR indicates that at least one of its member customers is willing to take service under such rates, DENC agrees to re-file such rates with the

Commission for approval with the modifications agreed upon within 60 days of such agreement.

At the hearing, Company witnesses Haynes and Miller stated their support for the CIGFUR Stipulation in the summaries of their testimonies. Witness Haynes stated that the CIGFUR Stipulation presents a just and reasonable approach to establishing the Company's North Carolina jurisdictional cost of service and class cost of service for the allocation of production and transmission plant costs and related expenses based on the SWPA allocation methodology. He indicated that the Company believes the CIGFUR Stipulation represents a reasonable compromise of the allocation and rate design issues in this case, is fair to all parties, and should be approved by the Commission. Witness Miller stated that the CIGFUR Stipulation represents a reasonable compromise of the cost of service issues in this case, is fair to all parties, and should be approved by the Commission. Tr. vol. 4, 497, 545.

Discussion and Conclusions

As with the Public Staff Stipulation, because the CIGFUR Stipulation has not been adopted by all of the parties to this docket the Commission's determination of whether to accept or reject the CIGFUR Stipulation is governed by the standards set out by the North Carolina Supreme Court in *CUCA I* and *CUCA II*.

The Commission gives significant weight to the testimony of DENC witnesses Haynes and Miller regarding the Company's support for the CIGFUR Stipulation.

As a result, the Commission finds and concludes that the CIGFUR Stipulation is the product of the give-and-take between the CIGFUR Stipulating Parties during their settlement negotiations in an effort to appropriately balance DENC's need for increased revenues and CIGFUR's interest in advocating for its member customers. In addition, the Commission finds and concludes that the CIGFUR Stipulation was entered into by the CIGFUR Stipulating Parties after discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket. As a result, the CIGFUR Stipulation is material evidence to be given appropriate weight in this proceeding.

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

Capital Structure

The evidence supporting these findings of fact and conclusions is contained in the testimony and exhibits of Company witness Davis, Public Staff witness Woolridge, CIGFUR witness Phillips, and the Public Staff and CIGFUR Stipulations, as well as testimony and exhibits presented at the hearing of this matter.

In his prefiled direct testimony, DENC witness Davis proposed a capital structure consisting of 53.01% common equity and 46.99% long-term debt, DENC's capital structure as of December 31, 2018. He discussed the Company's significant capital needs going forward, and explained how the Company plans to finance those capital needs, based on a balance of debt and common equity that DENC believes will support the Company's credit ratings going forward, and continue to enable the Company to access a number of markets, under a wide range of economic environments, on reasonable terms and conditions. Witness Davis stated that this market access is critical to fund the ongoing infrastructure capital expenditure programs that will be necessary to meet the Company's public service obligations in North Carolina and throughout its system. Tr. vol. 4, 204-09, 214-17.

In his supplemental testimony, witness Davis updated the Company's proposed capital structure to its actual structure as of June 30, 2019, which reflected a long-term debt component of 46.351% and an equity component of 53.649%. Based on the Company's proposed updated cost rates for long-term debt and common equity, witness Davis' proposed updated capital structure produced an updated overall weighted-average cost of capital of 7.826%. Tr. vol 4, 219-20.

Public Staff witness Woolridge testified that the Company's proposed capital structure included more common equity than the average of the proxy group he used in conducting his analysis. He stated that it is appropriate to use the common equity ratios of the parent holding companies and that the high debt ratio and low equity ratio of DEI is a credit negative for DENC as evaluated by Moody's. He noted, however, that because DENC is a regulated business, it is exposed to less risk and can carry relatively more debt in its capital structure than most unregulated companies, like DEI. Witness Woolridge further testified that DENC should take advantage of its lower business risk to employ cheaper debt capital at a level that will benefit its customers through lower revenue requirements and, as a result, recommended a capital structure of 50.00% common equity and 50.00% debt based on a 9.00% rate of return on common equity. Witness Woolridge also made an alternative capital structure recommendation of the Company's actual capital structure as of June 30, 2019, of 46.35% long-term debt and 53.65% common equity based on an 8.75% return on equity. Tr. vol. 6, 552-62.

CIGFUR witness Phillips testified that DENC's proposed capital structure includes more equity and less debt than other electric utilities and recommended a capital structure not to exceed 52.00% common equity. In support of his recommendation, witness Phillips analyzed the proxy groups that he claimed met the various jurisdictional regulatory capital structures of a comparable group of electric utility companies. He referenced groups that consisted of all electric utilities nationwide with equity ratios determined in the first half of 2019 and North Carolina gas and electric utilities that have had authorized rates of return on equity approved in recent years. Witness Phillips concluded that the Company's proposed capital structure was inconsistent with those authorized by the Commission in recent rate cases. Tr. vol 6, 412, 416, 429-31.

In his rebuttal testimony, witness Davis testified that witness Phillips' recommendation ignores the Company's actual capital structure as of June 30, 2019, as well as DENC's capital structure at year-end of each of the previous three years in favor of arbitrarily developed structures. Witness Davis stated that it is important that the Company's actual capital structure be considered in determining the appropriate capital structure for purposes of this rate case because imputing the structure of other peer utilities in different jurisdictions can lead to erroneous conclusions. He also explained that the Company's financing plan is structured to maintain the Company's current credit ratings, which provide the greatest benefit to customers in the long-term. Witness Davis stated that an arbitrarily derived capital structure could be viewed negatively by the Company's credit agencies. Finally, witness Davis explained that using the Company's actual capital structure helps to support the significant capital spending program the Company has and continues to undertake to enhance and improve DENC's generation and transmission infrastructure. Tr. vol. 6, 221-29.

Under Section III.A of the Public Staff Stipulation, the Stipulating Parties proposed a capital structure of 52% common equity and 48% long-term debt. In their stipulation testimony, Company witness Davis and Public Staff witnesses Johnson and McLawhorn testified that the capital structure reflected in the Public Staff Stipulation represents a compromise by both parties in an effort to reach agreement and is in the public interest. Witness Davis testified that the capital structure represented in the Stipulation provides an equity ratio that is 165 basis points lower than the Company's request of 53.649%, 200 basis points higher than the Public Staff's initial recommendation presented in witness Woolridge's testimony, and 25 basis points higher than the equity ratio authorized in the 2016 Rate Case. Witness Davis stated that he, like the Public Staff witnesses, believes the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that such a ratio will allow the Company to continue providing safe and reliable service to its customers. Tr. vol. 6, 51-52, vol. 4, 231-33.

In the CIGFUR Stipulation, CIGFUR and DENC stipulated that it was appropriate to use a capital structure consisting of 52% equity and 48% long-term debt.

In evaluating the evidence on capital structure in this proceeding, the Commission first notes that the equity/debt ratios reflected in the Stipulation of 52.00% equity and 48.00% long-term debt are consistent with and well within the prior experience of the Commission.[1] These are not determinative factors from the Commission's perspective, but they do provide some context supporting the reasonableness of the stipulated capital structure.

Based upon its own review and independent analysis of the evidence, the Commission concludes that a capital structure of 52.00% equity and 48.00% long-term debt, as is reflected in the Public Staff Stipulation, is just and reasonable and appropriate for use in this proceeding on several grounds.

First, this capital structure is very close, i.e., 25 basis points, to the capital structure authorized for DENC in its last rate case. Second, this capital structure was accepted by CIGFUR in the CIGFUR Stipulation. Third, while the Commission recognizes that Public Staff witness Woolridge recommended a 50% common equity and 50% debt capital structure based on a 9.00% rate of return on equity as his primary recommendation, he also proposed use of the actual capital

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

structure as of December 31, 2018, of 46.351% long-term debt and 53.649% common equity based on an 8.75% return on equity. Fourth, Section X of the Public Staff Stipulation provides:

> [T]his Stipulation is in the public interest because it reasonably balances customer interests in mitigating rate impacts with investor interests in providing for reasonable recovery of investments, thereby providing the necessary level of revenue requirement to allow the Company to maintain its financial strength and credit quality and continue to provide high quality electric utility service to its customers.

Fifth, Section IV of the CIGFUR Stipulation contains this same language. Sixth, the Commission gives substantial weight to Company witness Davis' testimony regarding the Company's effort to find the appropriate balance between equity and debt financing. As witness Davis noted, witness Phillips relies primarily on the averages of his respective proxy groups without providing any further rationale in support of his recommended capitalization ratios. Seventh, the Commission places substantial weight as well on witness McLawhorn's and witness Johnson's conclusion that the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that customers will benefit from lower rates as a result of a negotiated settlement that, if approved, will reduce the Company's proposed rate increase by at least $13 million. Eighth, the Commission also gives weight to the Public Staff Stipulation and the benefits that it provides to DENC's customers, which the Commission is obliged to consider as an independent piece of evidence under *CUCA I* and *CUCA II*. Each party to the Public Staff Stipulation gained some benefits that it deemed important and gave some concessions for those benefits. Based on the Application and pre-filed testimony, it is apparent that the Public Staff Stipulation ties the 52/48 capital structure to substantial concessions the Company made to reduce its revenue requirement.

Accordingly, based on the matters set forth above, and in the exercise of its independent judgment, the Commission finds that the weight of the evidence in this proceeding favors using the stipulated capital structure and that such capital structure is just, reasonable, and appropriate for use in setting rates in this docket.

Cost of Debt

The evidence supporting this finding of fact and conclusions is contained in the testimony and exhibits of Company witness Davis and Public Staff witness Woolridge, the Public Staff and CIGFUR Stipulations, and the entire record of this proceeding.

In its Application and supporting testimony, the Company proposed a long-term debt cost of 4.45% at the end of the test year. In his supplemental testimony, Company witness Davis updated the debt cost to 4.442% as of June 30, 2019. The Public Staff and CIGFUR Stipulations accept the 4.442% cost of debt proposed by the Company in witness Davis' supplemental testimony. No party contested the cost of debt proposed by the Company or agreed upon in the Public Staff and CIGFUR Stipulations.

The Commission, therefore, finds and concludes that the use of a debt cost of 4.442% is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-16

The evidence for these findings of fact and conclusions is contained in the Application; the direct testimony and exhibits of witnesses Hevert, Woolridge, and Phillips; the Public Staff and CIGFUR Stipulations; the testimony of public witnesses; the rebuttal testimony of witness Hevert; the settlement testimony of witnesses Hevert, McLawhorn, and Johnson; and the hearing testimony of witness Hevert.

The Public Staff and CIGFUR Stipulations both state that an allowed rate of return on common equity of 9.75% is reasonable for use in this proceeding, a decrease from the 9.9% level authorized by the Commission in the Company's last rate case. No other party presented evidence on the appropriate rate of return on common equity. The Commission's consideration of the evidence and decision on this issue is set out below and is organized into three sections. The first is a summary of the record evidence on rate of return on common equity. The second is a summary of the law applicable to the Commission's decision on rate of return on common equity. The third is an application of the law to the evidence and a discussion and explanation of the Commission's ultimate decision on rate of return on common equity.

Summary of Record Evidence on Return on Equity

In its Application, the Company requested approval for its rates to be set using an overall rate of return of 7.79% and a rate of return on equity of 10.75%. This request was based upon and supported by the direct testimony of DENC witness Hevert. These rates of return compare to an overall return of 7.367% and rate of return on common equity of 9.90% underlying DENC's current rates. DENC witness Mitchell also filed testimony supporting the approval of the rate of return on common equity recommended by witness Hevert. Witnesses for the Public Staff and CIGFUR also filed direct testimony on the appropriate rate of return on equity. This evidence was followed by the Public Staff and CIGFUR Stipulations, rebuttal testimony filed by witness Hevert, settlement testimony filed by DENC witness Hevert and Public Staff witnesses McLawhorn and Johnson, and finally testimony of witness Hevert at the hearing of this matter. In addition to this expert testimony, the Commission received the testimony of a number of public witnesses on DENC's proposed rate increase as well as numerous statements of consumer position. All of this evidence is summarized below.

Direct Testimony of Mark Mitchell (DENC)

DENC witness Mitchell testified that the Company was facing significant capital investment needs. He stated that in order to attract the capital to meet these substantial future needs, the Company must achieve an adequate authorized rate of return on common equity in this proceeding, and that the 10.75% rate of return on common equity proposed by DENC would allow the Company to attract capital on reasonable terms in the capital markets. He explained that the ability to attract capital on favorable terms is important to DENC's ability to maintain its current credit ratings and, ultimately, minimize the cost of capital for customers, and that an adequate return also ensures DENC's ability to commit capital to future construction projects to provide safe, reliable, and cost-effective electric service to North Carolina customers without eroding the Company's shareholders' interests. Tr. vol. 4, 168, 177-82.

Direct Testimony of Robert B. Hevert (DENC)

Witness Hevert, DENC's primary cost of equity witness, filed direct testimony and exhibits in support of DENC's request for a 10.75% rate of return on common equity. He explained that the cost of equity is the return that investors require to make an equity investment in a company, that it should reflect the return that investors require in light of the company's risks and the returns available on comparable investments, and that it differs from the cost of debt because it is neither directly observable nor a contractual obligation. In his direct testimony and exhibits, witness Hevert discussed the specific analyses he conducted in support of DENC's rate filing and provided a detailed description of the results of these analyses and resulting cost of equity recommendations. He applied the Constant Growth Discounted Cash Flow (DCF) model, the Capital Asset Pricing Model (CAPM), the Empirical Capital Asset Pricing Model (ECAPM), the Bond Yield Plus Risk Premium approach, and the Expected Earnings Analysis to develop his rate of return on equity recommendation. He stated that the Commission's decision should result in providing DENC with the opportunity to earn a rate of return on common equity that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. He discussed the need to select a group of proxy companies to determine the cost of equity, and how he selected the proxy group for this case. Witness Hevert also noted that the regulatory conditions approved by the Commission in the merger of DENC's parent company, DEI, and SCANA Corporation were designed to ensure that the Company has "sufficient access to equity and debt capital at a reasonable cost to adequately fund and maintain their current and future capital needs and otherwise meet their service obligations to their customers." Tr. vol. 4, 32-33.

According to witness Hevert, the results of his Constant Growth DCF analysis produced a rate of return on equity range of 8.34% to 10.38%. The results of witness Hevert's CAPM analysis showed a range of 8.25% to 11.34% in market risk premiums. The results of his ECAPM analysis showed a range of 9.61% to 12.76% in rate of returns on equity. The results of his Bond Yield Plus Risk Premium analysis indicated a rate of return on common equity range from 9.93% to 10.17%. The results of his Expected Earnings Analysis showed an average rate of return on common equity of 10.38% and a median rate of return on equity of 10.52%. Based on his analyses, witness Hevert concluded that a rate of return on common equity in the range of 10.00% to 11.00% represents the rate of return on common equity required by equity investors for investment in integrated electric utilities in today's capital markets. Within that range, he recommended a rate of return on common equity for DENC of 10.75% in both his direct and rebuttal testimony. Tr. vol. 4, 45-56.

Witness Hevert explained that his rate of return on common equity recommendation also took into consideration several additional factors, including (1) DENC's need to fund its substantial planned capital investment program, (2) the regulatory environment in which the Company operates, and (3) flotation costs. With regard to the regulatory environment, he noted that North Carolina is generally considered to be a constructive regulatory jurisdiction, and that authorized rates of return on common equity tend to be correlated with the degree of regulatory supportiveness (utilities in jurisdictions considered to be more supportive tend to be authorized somewhat higher returns). He did not, however, make any specific adjustment to his rate of return on common equity estimates for the effect of these factors. Tr. vol. 4, 56-67.

Witness Hevert also addressed the capital market environment and testified that it is important to assess the reasonableness of any financial model's results in the context of observable market data. In particular, he discussed the fact that investors see a probability of increasing interest rates based on near-term forecasts of the 30-year Treasury yield. Tr. vol. 4, 77-81.

Witness Hevert also considered the economic conditions in North Carolina in arriving at his rate of return on common equity recommendation. He noted that the rate of unemployment has fallen substantially in North Carolina and in the U.S. generally since late 2009 and early 2010, with December 2018 rates of 3.70% in the State. He noted that since the Company's last general rate filing in March 2016, unemployment in the counties served by DENC has fallen by 1.40%. Witness Hevert also noted that since the second quarter of 2013, the State has generally matched the national rate for real GDP, but that since 2009, median household income in North Carolina has grown at a somewhat slower annual rate than the national median income annual rate than the national median income. Total personal income, disposable income, personal consumption, and wages and salaries were generally on an increasing trend. Finally, he noted that since 2018, residential electricity costs in North Carolina remain approximately 13.00% below the national average. Based on all of these factors, witness Hevert opined that North Carolina and the counties contained within DENC's service area have experienced steady economic improvement since the Company's last rate case and that improvement is projected to continue. In his opinion, DENC's proposed rate of return on common equity is fair and reasonable to DENC, its shareholders and its customers, in light of the impact of changing economic conditions on DENC's customers. Tr. vol. 4, 67-77.

Direct Testimony of J. Randall Woolridge (Public Staff)

Public Staff witness Woolridge performed DCF and CAPM analyses for both his and witness Hevert's proxy groups of electric utilities. Witness Woolridge developed his DCF growth rate after reviewing 13 growth rate measures including historic and projected growth rate measures and evaluating growth in dividends, book value, earnings per share (EPS), and growth rate forecasts from Yahoo, Reuters, and Zack's. Witness Woolridge testified that it is well known that long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. Public Staff witness Woolridge determined a DCF equity cost rate of 8.55% for his proxy group, and 8.95% for the witness Hevert proxy group. Tr. vol. 6, 534-37.

In witness Woolridge's CAPM analysis, he used for the risk free interest rate the top end of the range of yields on 30-year U.S. Treasury bonds over the 2013-2019 time period, 4.00%. He used the Value Line Investment Survey betas of 0.60 for his proxy group and 0.58 for witness Hevert's proxy group. Witness Woolridge's market risk premium was 5.50%, based in part on the June 2019 CFO survey conducted by CFO Magazine and Duke University, which included approximately 200 responses, in which the expected market risk premium was 4.05%. He testified that thus, his 5.50% value is a conservatively high estimate of the market risk premium. Witness Woolridge also testified that Duff & Phelps, a well-known valuation and corporate finance advisor that publishes extensively on cost of capital, recommended on December 31, 2018, using a 5.5% market risk premium, for the U.S. Witness Woolridge's CAPM equity cost rate was 7.30% for his proxy group and 7.20% for witness Hevert's proxy group. Tr. vol. 6, 591-604.

Witness Woolridge concluded that the appropriate equity cost rate for companies in his and witness Hevert's proxy groups is in the 7.20% to 8.95% range. He gave primary weight to his DCF results based on his belief that risk premium studies, including the CAPM, are a less reliable indicator of equity cost rates for public utilities. Witness Woolridge also indicated that he found the DCF model to provide the best measure of equity cost rates considering the investment valuation process and the relative stability of the utility business. Tr. vol. 6, 531, 604-05.

While noting that his equity cost rate studies indicated a rate of return on common equity between 7.20% and 8.95%, witness Woolridge took into account the fact that his range was below the authorized rates of return on common equity for electric utilities nationally and made a primary recommendation of a 9.00% rate of return on equity, assuming a 50.00% common equity ratio. Witness Woolridge also provided an alternative recommendation of an 8.75% rate of return on common equity based on the Company's originally recommended equity ratio of 53.649%. Tr. vol. 6, 532-33.

Witness Woolridge did not perform an ECAPM analysis and testified that the ECAPM is an ad hoc version of the CAPM and has not been theoretically or empirically validated in refereed journals. He also took issue with witness Hevert's Bond Yield Plus Risk Premium analysis and argued that it is inflated, gauges commission behavior rather than investor behavior, and overstates the actual rate of return on common equity. Tr. vol. 6, 612-13, 640-44.

Witness Woolridge also expressed concerns with witness Hevert's Expected Earnings analysis and argued that the approach is inappropriate for several reasons: (1) it is accounting based and does not measure market based investor return requirements; (2) book equity does not change with investor return requirements as do market prices; (3) there is a negative relationship between the Return on Common Equity and Common Equity ratios; (4) the approach is circular; and (5) the data partially reflect earnings of non-regulated operations. Tr. vol. 6, 613, 644-48.

Witness Woolridge also testified as to current capital market conditions as of the date of his testimony in August 2019. He stated that although the Federal Reserve increased the Federal Funds rate between 2015 and 2018, interest rates and capital costs remained at low levels. Witness Woolridge also pointed out that the 30-year Treasury yields are at historically low levels and are accompanied by slow economic growth and low inflation. Tr. vol. 6, 548, 591, 610.

Witness Woolridge responded to witness Hevert's assessment of the economic conditions in North Carolina. He generally agreed with witness Hevert's review of several measures of economic conditions, including the rate of unemployment, real GDP growth, median household income, residential electricity rates, and broad measures of income and consumption, as well as witness Hevert's general conclusion that economic conditions in North Carolina have improved since the Company's last rate case. Witness Woolridge argued, however, that although economic conditions generally have improved, other conditions such as the higher unemployment rate in the DENC service territory as opposed to the whole state, and the median household income in North Carolina that is lower than the national norm, as well as the over 100 basis point difference in DENC's requested rate of return on common equity and the average authorized rates of return on equity for electric utilities in 2018-2019, do not support the Company's proposed rate of return. Tr. vol. 6, 652-55.

Direct Testimony of Nicholas Phillips, Jr. (CIGFUR)

CIGFUR witness Phillips did not perform cost of capital analyses. In his testimony witness Phillips found the Company's proposed rate of return on equity to be excessive based on his review of authorized rates of return on common equity for the first half of 2019, which averaged 9.57%, as reported by RRA. Witness Phillips recommended that the Commission authorize a rate of return on common equity that does not exceed the national average of 9.57%. Tr. vol. 6, 427-31.

Rebuttal Testimony of Robert B. Hevert (DENC)

In his rebuttal testimony, Company witness Hevert responded to the arguments raised by CIGFUR witness Phillips. Witness Hevert explained that he analyzed the authorized rate of return on common equity for vertically integrated electric utilities based on the jurisdiction's ranking by RRA, which provides an assessment of the extent to which regulatory jurisdictions are constructive from investors' perspectives. Witness Hevert stated that according to RRA, less constructive environments are associated with higher levels of risk, but North Carolina currently is ranked "Average/1," which falls approximately in the top-third of the 53 jurisdictions ranked by RRA. Witness Hevert testified that authorized rates of return on common equity for vertically integrated electric utilities in jurisdictions rated in the top third of all jurisdictions, like North Carolina, range from 9.37% to 10.55%, with an average of 9.93%, and a median of 9.95%. Finally, witness Hevert pointed to Company Rebuttal Exhibit RBH-16, which shows that the mean and median authorized rates of return on common equity for 2019, updated through August 16, 2019, are 9.61% and 9.73%, respectively. Tr. vol. 4, 107-12.

Public Staff and CIGFUR Stipulations

In both the Public Staff and the CIGFUR Stipulations, DENC and the Public Staff, and DENC and CIGFUR agreed that the appropriate overall rate of return and rate of return on common equity for use in this proceeding were 7.20% and 9.75%, respectively. These agreements represent substantial movement by the parties from the positions on overall return and return on common equity articulated in testimony. This stipulated overall return of 7.20% and return on common equity of 9.75% was supported by settlement testimony filed by Company witness Hevert. The overall reasonableness of the stipulated rates of return was also addressed by Public Staff witnesses McLawhorn and Johnson in their settlement testimony.

Settlement Testimony of Robert B. Hevert (DENC)

In his testimony supporting the Stipulations, witness Hevert noted that although the 9.75% stipulated rate of return on common equity is somewhat below the lower bound of his recommended range, he recognized that the Stipulations reflect negotiation on many issues between the parties. Witness Hevert stated that the terms of the Stipulations, when taken as a whole, would be regarded favorably by the financial community. He noted that the median rate of return on common equity authorized in 2019 at the time of his testimony was 9.73%, only two basis points from the stipulated rate of return on common equity. Witness Hevert testified that the stipulated rate of return on common equity fell below his Risk Premium model results, it fell in the 69th percentile of the mean and median of his DCF results, the 32nd percentile of his CAPM and ECAPM results, and the 40th percentile of his Expected Earnings analysis. Thus, witness Hevert concluded that the stipulated rate of return on equity was supported by returns in other jurisdictions and fell within the range of his model results, though at the lower end. Tr. vol. 4, 116-19.

Hearing Testimony of Robert B. Hevert (DENC)

Under cross-examination by the AGO, witness Hevert defended the use of projected treasury yields in his CAPM analysis by pointing out that there was only about a 21-basis point difference between the current and projected treasury yields, which was not a material difference. He noted that the CAPM results based on the current yield also support his recommendation. Witness Hevert also pointed out that using projected yields gave an important perspective, especially in light of the fact that in the recent market, the 30-year Treasury yield fell 71 basis points in 34 trading days. He further pointed out that in the Sub 1142 Order in DEP's 2017 rate case and a recent Virginia case the commissions found his DCF analysis to produce unreasonably low rate of return on equity results, even using only earnings estimates. Witness Hevert did not dispute that of the 32 data points he considered in determining his range and recommended rate of return on equity, 24 were lower than his recommended rate of return on common equity. Nonetheless, witness Hevert noted that a mean of these results would not necessarily provide an appropriate estimate of DENC's cost of equity, as various qualitative factors should also be considered, such as capital expenditure plans and the regulatory environment. Tr. vol. 4, 143-47.

Public Witness Testimony/Statements of Consumer Position

In addition to the direct prefiled testimony of the expert witnesses for the parties, a number of public witnesses also gave testimony suggesting that DENC customers would experience difficulty paying the increased rates requested in the Application and opposing the rate increases proposed by DENC. The Commission also received numerous statements of consumer position with regard to this docket, many of which expressed concern about DENC's proposed rate increase.

Law Governing the Commission's Decision on Return on Equity

Rate of return on common equity is often one of the most contentious issues to be addressed in a rate case, even in a case such as this one in which stipulations between DENC and the Public Staff and DENC and CIGFUR have been reached. In the absence of a settlement agreed to by all the parties, the law of North Carolina requires the Commission to exercise its independent judgment and arrive at its own independent conclusion as to the proper rate of return on common equity. *See, e.g., CUCA I*, 348 N.C. at 466, 500 S.E.2d at 707. In order to reach an appropriate independent conclusion regarding the rate of return on common equity, the Commission must evaluate the available evidence, particularly that presented by conflicting expert witnesses. *State ex rel. Utils. Comm'n v. Cooper*, 366 N.C. 484, 491-93, 739 S.E.2d 541, 546-47 (2013) (*Cooper I*). In this case, the expert witness evidence relating to the Company's cost of equity capital was presented by Company witness Hevert, Public Staff witness Woolridge, and CIGFUR witness Phillips. No return on equity evidence was presented by any other party.

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

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

DEC Sub 1146 Order at 50; *see also State ex rel. Utils. Comm'n v. Gen. Tel. Co. of the Se.*, 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972) (*General Telephone*). As the North Carolina Supreme Court held in *General Telephone*, these factors constitute "the test of a fair rate of return declared" in *Bluefield* and *Hope*. *Id.*

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

> Each is a part of the current cost of supplying the service; and each should be met from current income. When the capital charges are for interest on the floating debt paid at the current rate, this is readily seen. But it is no less true of a legal obligation

> to pay interest on long-term bonds . . . *and it is true also of the economic obligation to pay dividends on stock, preferred or common.*

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

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

> While utilities enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free open market for the input factors of production, whether it be labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices which are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on capital debt, or the expected return on equity.
>
> . . .
>
> [T]he cost of capital to the utility is synonymous with the investor's return, and the cost of capital is the earnings which must be generated by the investment of that capital in order to pay its price, that is, in order to meet the investor's required rate of return.

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

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

Id. at 20.

In addition, the Commission is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions. *State ex rel. Utils. Comm'n v. Pub. Staff-N. Carolina Utils. Comm'n*, 323 N.C. 481, 490, 374 S.E.2d 361, 370 (1988) (*Public Staff*).

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." Order Granting General Rate Increase, *Application of Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North* Carolina, No. E-2, Sub 1023, at 37 (N.C.U.C. May 30, 2013), *aff'd*, *State ex rel. Utils. Comm'n v. Cooper*, 367 N.C. 444, 761 S.E.2d 640 (2014) (2013 DEP Rate Case Order). 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 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*, 366 N.C. at 484, 739 S.E.2d at 548.

The Commission further noted in the 2013 DEP Rate Case Order that while there is no specific and discrete numerical basis for quantifying the impact of economic conditions on customers, the impact on customers of changing economic conditions is embedded in the rate of return on equity expert witnesses' analyses. The Commission noted this in the 2013 DEP Rate Case Order:

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

2013 DEP Rate Case Order at 38.

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

> Indeed, of all the components of a utility's cost of service that must be determined in the ratemaking process the appropriate [rate of return on common equity] is the one requiring the greatest degree of subjective judgment by the Commission. Setting [a rate of return on common equity] for regulatory purposes is not simply a mathematical exercise, despite the quantitative models used by the expert witnesses. As explained in one prominent treatise,

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

> Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the commissions are supposed to consider in making their decisions, but no weights have been assigned.
>
> The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.
>
> In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:
>
> > There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.
>
> As long as the allowed return falls within this zone, therefore, it is just and reasonable. . . . It is the task of the commissions to translate these generalizations into quantitative terms.

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

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

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

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

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

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

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

Discussion and Application of Law to the Facts

The Commission has examined the Company's Application and supporting testimony and exhibits and Form E-1 filings seeking to justify its requested increase. DENC's updated request prior to entering into the stipulations was a retail revenue increase of $24.2 million in annual revenues. The Public Staff, who in this docket represents all users and consumers of the Company's electric service, and DENC entered into a stipulation that resulted in reducing the retail revenue increase sought by the Company. CIGFUR and DENC entered into a separate stipulation that provided for the same reduction in the revenue increase, as well as a 9.75% rate of return on common equity. As with all settlement agreements, each party to the stipulations gained some benefits that it deemed important and gave some concessions for those benefits. Based on DENC's Application, it is apparent that the stipulations tie the 9.75% rate of return on common equity to substantial agreed upon concessions made by DENC. As noted above, since the AGO and Nucor, parties in this docket, did not agree to the settlements, the Commission is required to examine the stipulations and exercise its independent judgment to arrive at its own independent conclusion as to the proper rate of return on common equity.

The starting point for an examination of what constitutes a reasonable rate of return on common equity begins with the various economic and financial analyses provided by the parties' expert witnesses. In this proceeding, those analyses were provided in the testimonies of three different witnesses: witness Hevert for DENC; witness Woolridge for the Public Staff; and witness Phillips for CIGFUR. These testimonies, as summarized above, provide a relatively broad range of methods, inputs, and recommendations regarding the proper rate of return on common equity determination for DENC. For example, witness Hevert relied in his direct testimony on four different analyses to arrive at his rate of return on common equity recommendation. These analyses were a Constant Growth DCF Analysis, a Capital Asset Pricing Model analysis, an Empirical Capital Asset Pricing Model, a Bond Yield Plus Risk Premium analysis, and an Expected Earnings analysis. By way of comparison, Public Staff witness Woolridge relied upon a DCF analysis and a Capital Asset Pricing Model analysis in reaching his conclusions; however, the inputs utilized by witness Woolridge in his analyses are different from those utilized by witness Hevert. Witness Phillips looked at the average allowed rates of return on common equity for both vertically integrated and distribution-only electric utilities for the first and second quarters of 2019 of 9.57% and recommended that average as a cap to the allowed rate of return on common equity.

These varying analyses, as is typical, produced varying results. Witness Hevert's analyses prompted him to propose a rate of return on common equity range of 10.00% to 11.00% with a specific rate of return on common equity recommendation of 10.75%. Witness Woolridge's analyses resulted in a recommended rate of return on common equity range of 7.20% to 8.95% with a primary recommendation of a 9.00% rate of return on common equity with a 50.00%

common equity capital structure and a secondary recommendation of an 8.75% rate of return on common equity if DENC's actual capital structure of 46.351% long-term debt and 53.649% common equity, as proposed in the supplemental testimony of Company witness Davis, was approved. Finally, as noted above, witness Phillips recommended a cap on rate of return on common equity of 9.57%.

The Commission finds the cost of equity analyses helpful in reaching its conclusion on an appropriate rate of return on common equity for DENC, but notes that the ranges of the various analyses span a range from 7.20% to 12.76% and the specific rate of return on common equity recommendations of the witnesses span a range from 8.75% on the low end to 10.75% on the high end.

The Commission finds that the DCF, CAPM, ECAPM, and Bond Yield Plus Risk Premium analyses of DENC witness Hevert, and the stipulations are credible, probative, and entitled to substantial weight.

DENC witness Hevert in his direct testimony provided his constant growth DCF analyses, as shown on Exhibit RBH-1, pages 1, 2, and 3: 30-day dividend yield mean 9.24%, median 9.18%; 90-day dividend yield mean 9.31%, median 9.25%; and 180-day dividend yield mean 9.39%, median 9.38%. Although the Commission, as stated in previous Commission general rate case orders, does not approve of witness Hevert's sole use of analysts' predicted earnings per share to determine the DCF growth rate, the Commission finds witness Hevert's constant growth DCF analyses mean and median rate of return on common equity results credible, probative, and entitled to substantial weight.

Witness Hevert's CAPM analysis for his Proxy Group Average Value Line Beta Coefficient, as shown on Exhibit RBH-4, page 1, includes current 30-year treasury rates to calculate the risk free rate of 3.04%, producing what witness Hevert described as a Value Line Market DCF Derived rate of return on equity of 9.78%. Witness Hevert's ECAPM analysis for his Proxy Group Average Bloomberg Beta Coefficient, as shown on Exhibit RBH-4, page 1, produces what witness Hevert described as a Bloomberg Market DCF Derived rate of return on common equity of 9.61%. The Commission approves of the use of current risk-free rates rather than predicted near-term or long-term rates. The Commission finds the above-described CAPM and ECAPM analyses credible, probative, and entitled to substantial weight.

DENC witness Hevert's Bond Yield Plus Risk Premium, as shown on Exhibit RBH-5, using the current 30-year Treasury yield of 3.04% and applying it to the approved rates of return on common equity in 1,581 electric utility rate proceedings between January 1980 and February 28, 2019, results in a rate of return on common equity of 9.93%. As previously stated, the Commission approves the use of current interest rates, rather than projected near-term or long-term interest rates. The Commission finds witness Hevert's updated Bond Yield Plus Risk Premium analysis using the current 30-year Treasury yield to be credible, probative, and entitled to substantial weight.

The Commission has carefully evaluated the DCF analysis recommendation of witness Woolridge. As shown on witness Hevert's settlement testimony Exhibit RBH-S-1, from 2016 –

2019, there were 81 vertically integrated electric utility decisions by public service commissions resulting in a mean approved 9.74% rate of return on common equity. The mean year-to-date 2019 rate of return on common equity is 9.61%, and the median rate of return on equity is 9.73%.

As shown on Exhibit RBH-S-1, during this period there was only one public service commission (the South Dakota Public Service Commission) decision approving a rate of return on common equity below 9.00% for a vertically integrated electric utility (8.75% in May 2019). Public Staff witness Woolridge's DCF analysis produced a rate of return on common equity ranging from 8.55 – 8.95%, adjusted upward for a specific rate of return on common equity recommendation of 9.00% with a 50.00% common equity capital structure component. As shown on Exhibit JRW-8, page 1, the result of the CAPM analysis for the Electric Proxy Group and the Hevert Proxy Group were 7.3% and 7.2%, respectively. These DCF and CAPM results are substantially below the mean allowed rate of return on common equity of 9.74% from 2016 through mid-September 2019.

In summary, the Commission concludes there is substantial evidence supporting the reasonableness of a rate of return on common equity of 9.75%. First, that rate of return is well within the range of recommended returns by the economic experts in this docket of 7.20% to 11.00%. Second, it falls just 36 basis points above the 9.39% mean results of DENC witness Hevert's DCF analysis and below the mean high results of his DCF analysis. Third, it falls within the range of DENC witness Hevert's CAPM results. Fourth, it falls within the results of DENC witness Hevert's ECAPM results. Fifth, it falls only 18 basis points below the lower end of the range of DENC witness Hevert's Bond Yield Plus Risk Premium analysis results. Sixth, it is slightly below the recommended range of DENC witness Hevert (10.00% to 11.00%). Seventh, it falls squarely within the range and very close to the average of recent vertically-integrated electric utility allowed rates of return on common equity nationally.[1] Eighth, it is equal to the lowest rate of return on equity awarded by this Commission in general rate cases for major electric utilities in at least the last 10 years.[2] Ninth, it is 15 basis points lower than DENC's current allowed rate of return on common equity. Tenth, it is supported as the appropriate rate of return on common equity for DENC by all of parties filing rate of return testimony in this proceeding in lieu of the recommendations made by their respective witnesses on this subject, and the stipulated rate of return on common equity of 9.75% is supported by credible filed settlement testimony by the cost of capital witness for DENC. Finally, and without expressly adopting his methodology, it is consistent with witness Phillips' notion that DENC's return should be capped at the average rate

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

[2] *See* Docket Nos. E-2, Subs 1023 and 1142; E-7, Subs 909, 989, and 1146; and E-22, Subs 459, 479, and 532.

of return on common equity approved by other state commissions for the first two quarters of 2019.[1]

These factors lead the Commission to conclude that a 9.75% rate of return on common equity is supported by the substantial weight of the evidence in this proceeding. However, to meet its obligation in accord with the holding in *Cooper I*, the Commission will next address the impact of changing economic conditions on customers.

In this case, all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers. The testimony of witnesses Hevert and Woolridge, which the Commission finds entitled to substantial weight, addresses changing economic conditions at some length. Witness Hevert provided detailed data concerning changing economic conditions in North Carolina, as well as nationally, and concluded that the North Carolina-specific conditions are "highly correlated" with conditions in the broader nationwide economy. As such, witness Hevert testified that changing economic conditions, both nationally and specific to North Carolina, are reflected in his rate of return on common equity estimates.

Public Staff witness Woolridge agreed with DENC witness Hevert that economic conditions have improved in North Carolina. He pointed out that while the State's unemployment rate has fallen by one-third since its peak in the 2009-2010 period and is slightly below the national average of 3.90%, the unemployment rate in DENC's service territory is 4.95%, over 100 basis points higher than the national and North Carolina averages. Witness Woolridge also noted that North Carolina's residential electric rates are below the national average; however, its median household income is more than 10% below the U.S. norm.

Based upon the general state of the economy and the continuing affordability of electric utility service, and after weighing and balancing factors affected by the changing economic conditions in making the subjective decisions required, the Commission concludes that the stipulated rate of return on common equity of 9.75% will not cause undue hardship to customers even though some will struggle to pay the increased rates resulting from the Stipulations. When the Commission's decisions are viewed as a whole, including the decision to establish the rate of return on common 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.[2]

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[1] Witness Phillips' proposal was a cap at 9.57% based on the first and second quarter average rates of return reported by RRA. However, witness Phillips included distribution-only electric utilities, which are not appropriate. DENC witness Hevert's rebuttal testimony explained that the results reported by Mr. Phillips were skewed by the Otter Tail decision, and a better measure was the median rate of return on common equity authorized for vertically-integrated utilities in 2019 through August 2019 of 9.73%, as opposed to the mean of 9.61%. The Commission finds the use of vertically-integrated electric utilities to be a more comparable measure, as well as the more current data.

[2] The Commission notes that consumers pay "rates," a charge in cents per kilowatt-hour (kWh) for the electricity they consume. They do not pay a "rate of return on common equity," though it is a component of the Company's cost of providing service which is built into the charge per kWh. Investors are compensated by earning a return on the capital they invest in the business. Per the Commission determination of the rate of return on common equity in this matter, investors will have the opportunity to be paid in dollars for the dollars they invested at the rate of 9.75%.

The many Commission-approved adjustments reduced the revenues to be recovered from customers and the return to be paid to equity investors. Some adjustments reduced the authorized rate of return on investment financed by equity investors. These adjustments have the effect of reducing rates and providing rate stability to consumers (and return to equity investors) in recognition of the difficulty some consumers will have paying increased rates in the current economic environment. While the equity investor's cost was calculated by resort to a rate of return on common equity of 9.75% instead of 10.75%, this is only one approved adjustment that reduced ratepayer responsibility and equity investor reward. Many other adjustments reduced the dollars the investors actually have the opportunity to receive. Therefore, nearly all of the adjustments reduce ratepayer responsibility and equity investor returns in compliance with the Commission's responsibility to establish rates as low as reasonably permissible without transgressing constitutional constraints, and thus, inure to the benefit of consumers' ability to pay their bills in this economic environment.

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

Considering the changing economic conditions and their effects on DENC's customers, the Commission recognizes the financial difficulty that an increase in DENC's rates may create for some of DENC's customers, especially low-income customers. As shown by the evidence, relatively small changes in the rate of return on common equity have a substantial impact on a utility's base rates. Therefore, the Commission has carefully considered changing economic conditions and their effects on DENC's customers in reaching its decision regarding DENC's approved rate of return on common equity.

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

The Commission concludes in the exercise of its independent judgment and discretion that a 9.75% rate of return on common equity is supported by the evidence and should be adopted. The hereby approved rate of return on common equity appropriately balances the benefits received by

DENC's customers from DENC's provision of safe, adequate, and reliable electric service in support of the well-being of the people, businesses, institutions, and economy of North Carolina (which benefits are symbiotically linked to the Company's ability to compete in the equity capital market to access capital on reasonable terms that will be fair to ratepayers) with the difficulties that some of DENC's customers will experience in paying DENC's adjusted rates. The Commission further concludes that a 9.75% rate of return on common equity will allow DENC to compete in the market for equity capital, providing a fair return on investment to its investor-owners and, the lowering of the rate from the requested 10.75% to 9.75% has the effect of lowering the cost of service which forms the basis the rates the ratepayers must pay for service. Accordingly, the Commission concludes, taking into account changing economic conditions and their impact on customers that the approved rate of return on common equity will result in the lowest rates constitutionally permissible in this proceeding.

Finally, in approving the 9.75% rate of return on common equity, the Commission gives significant weight to the stipulations and the benefits that they provide to DENC's customers, which the Commission is obliged to consider as an independent piece of evidence under the Supreme Court's holding in *CUCA I*.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17-26

The evidence supporting these findings of fact and conclusions are contained in DENC's verified Application and Form E-1, the testimony and exhibits of the witnesses, the Public Staff Stipulation, and the entire record in this proceeding.

The Company and the Public Staff agreed to certain cost of service adjustments addressed in the testimony of Public Staff witness Johnson, the rebuttal testimony of Company witness McLeod, and as further negotiated by the Stipulating Parties. These adjustments are shown on Settlement Exhibit I of the Public Staff Stipulation and are each described below. The resolution of the various adjustments as reflected in the Public Staff Stipulation should be viewed holistically as the result of the give and take negotiations between the Stipulating Parties, rather than as a separate agreement of each Stipulating Party on the amount adjusted in each of the adjustments.

Updates Through June 30, 2019

The Company provided actual updates to certain revenues, expenses and investments through June 30, 2019, as evidenced through supplemental testimony filed August 5, 2019; and second supplemental testimony filed on September 12, 2019, by the Company. The Public Staff and the Company adjusted several of these updates, as reflected in the Public Staff Stipulation. No party took issue with any of these updates. The Commission concludes that these updates are just and reasonable and should be included in rates.

Greensville CC Costs

DENC included in rates for the proceeding approximately $1.3 billion in costs to complete the Greensville CC. This new baseload CC was placed into service on December 8, 2018 and has a capacity of approximately 1,588 MW. Tr. vol. 4, 171. In its testimony, DENC requested that the incremental costs incurred from the time this major new generating facility was placed into service in December 2018 until such time as the costs will be reflected in the base non-fuel rates approved in this proceeding be deferred and amortized over a three-year period beginning with the effective date the Commission approves new rates in this proceeding. Tr. vol. 4, 276.

No party provided testimony challenging the allowance of the deferral for the Greensville CC, nor did any party disagree with the amortization period requested by the Company. The Commission finds and concludes that the Company's request to defer the costs of the Greensville CC and amortize them over three years is just and reasonable to all parties in light of all the evidence presented.

Executive Incentive Compensation

In his direct testimony, witness McLeod testified that the Annual Incentive Plan (AIP) represents at-risk compensation paid out to Company employees only upon meeting certain operation and financial goals during the plan year. He stated that the Company made an adjustment that provided for 100% of the plan target instead of the 120% payout that occurred during the test year. Tr. vol. 4, 267.

In her testimony, Public Staff witness Johnson described the Company's AIP and Long-Term Incentive Plan (LTIP) and how eligible employee's performance is evaluated by the Company and what metrics are used in determining an employee's compensation under one or both of the plans. Witness Johnson testified that she adjusted the allowable costs of AIP to exclude incentive amounts that were based on financial metrics, which are closely tied to EPS, as the AIP as a whole is funded based on a consolidated EPS. Witness Johnson removed amounts related to all executive-level employees because she claimed that those employees' goals align with shareholders' interests. Finally, witness Johnson adjusted the LTIP costs allowed to exclude Performance Shares because the Public Staff believes that the metrics used in calculating Performance Shares provide direct benefits to shareholders rather than ratepayers. Tr. vol. 6, 19-20.

The Public Staff Stipulation provides for the removal of 50% of the costs associated with the Company's executive incentive plan that were based on financial metrics and otherwise retained the Company's proposal. The Commission finds and concludes that the Public Staff Stipulation's treatment of the incentive plan costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Employee Severance Program Costs

In his direct testimony, witness McLeod testified that the Company made an adjustment to include a normalized level of employee severance costs in the cost of service based on the Company's historical experience over the past 24 years. He explained that since 1994 there were five major corporate-wide severance programs which resulted in an average of approximately one every five years. Tr. vol. 4, 266-67.

In his supplemental testimony, witness McLeod explained that in March 2019, the Company announced the Voluntary Retirement Program (VRP) for employees that meet certain age and service requirements. Witness McLeod stated that the VRP was offered to employees of nearly all DEI affiliates, including DENC and Dominion Energy Services, Inc. (DES), and is expected to reduce total workforces during the remainder of 2019 and 2020. He also testified that the VRP is expected to result in a cost savings due to efficiencies gained and confirmed that the Company's supplemental filing incorporated the VRP severance costs as well as the savings through adjustments to employee salaries and wages, benefits, and AIP costs. Witness McLeod further testified that the revenue requirement presented in the Company's supplemental filing has comprehensively incorporated the severance costs and savings associated with the VRP. Additionally, Witness McLeod updated the employee severance program normalization adjustment to include VRP-related severance costs. During the period 1994 through 2019, there were six major corporate-wide severance programs instituted by the Company, resulting in an average of approximately one every 4.17 years. Tr. vol. 4, 305, 311.

In her testimony, witness Johnson stated that the Public Staff would typically include a normalized level of employee severance program costs and use the actual costs of the Company's latest corporate-wide severance program, amortized over a reasonable period of time. However, the circumstances in this docket are distinguishable. Public Staff witness Johnson took exception with using VRP severance costs in the employee severance program cost adjustment because she claimed these costs "appear to be closely linked" to the DEI and SCANA merger approved by the Commission in 2018. *See* Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, *Joint* Application *of Dominion Energy, Inc., and SCANA Corporation to Engage in a Business Combination Transaction*, Nos. E-22, Sub 551, G-5, Sub 585 (N.C.U.C. Nov. 19, 2018) (SCANA Merger Order). Witness Johnson acknowledged that the Company reflected a reduction to salaries and wages, benefits, AIP, and payroll taxes in its supplemental filing as a result of the VRP but disagreed with including the VRP severance costs in the normalized employee severance program calculation. Witness Johnson claimed that the VRP severance costs should be considered "integration costs" as defined in the SCANA Merger Order and pursuant to that order, integration costs should not be included for ratemaking purposes. Witness Johnson proposed retaining the existing normalized level of employee severance costs that was calculated and approved in the 2016 Rate Case. Tr. vol. 6, 20-24.

For purposes of this proceeding, the Public Staff Stipulation provides for a reduction in the revenue requirement in the amount of $304,000 to reflect a downward adjustment for the costs related to the employee severance program requested in this case and a normalization of those costs over 4.5 years. The Commission finds and concludes that the Public Staff Stipulation's treatment of the severance costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

VRP Employee Backfill Costs

In his supplemental testimony, witness McLeod testified that the Company made an adjustment that offset a portion of the VRP savings incorporated in the employee labor and benefits adjustments with a calculated value of salaries and wages for backfilled positions. Tr. vol. 4, 317.

In her testimony, Public Staff witness Johnson made an adjustment to remove the 582 planned positions for both DENC and DES that the Company intended to fill as a result of the VRP. Witness Johnson explained that because these positions have not actually been filled, the costs of those positions should not be included in this proceeding. Witness Johnson explained that should the Company hire any of these employees and provide supporting documentation, up to the close of the hearing in this docket, then she would update her testimony accordingly after investigation and verification that the employees had been hired. Tr. vol. 6, 24.

For purposes of this proceeding, the Public Staff Stipulation provides for an adjustment to the requested revenue requirement for the employee severance program as described above and for the Public Staff's withdrawal of its proposed adjustment for the related VRP backfill costs. The Commission finds and concludes that the Public Staff Stipulation's treatment of the employee backfill costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Storm Restoration Expense

In his direct testimony, witness McLeod explained that it is appropriate to include a normalized level of storm expense in the cost of service for ratemaking purposes given the unpredictable nature of storm activity that can cause a material level of expense in a short period of time. The Company used a historical average of storm activity and cost during the nine years of 2010–2018 in determining its normalized level of expense. Tr. vol. 4, 268.

In her testimony, Public Staff witness Johnson made an adjustment to the Company's normalized level of major storm restoration expenses by calculating the average costs for the last ten years instead of nine as used by the Company. Witness Johnson stated that a ten-year average was consistent with the method used in the most recent rate cases for DEC and DEP in Docket Nos. E-7, Sub 1146 and E-2, Sub 1142, respectively. Tr. vol. 6, 25-26.

For purposes of this proceeding, the Public Staff Stipulation provides for a reduction in the revenue requirement in the amount of $81,000 to reflect a downward adjustment for the storm costs requested in this case. The Commission finds and concludes that the Public Staff Stipulation's treatment of the storm restoration costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Advertising Expense

In his direct testimony, witness McLeod testified that the Company made an adjustment to eliminate all promotional advertising expenses from the test year. Tr. vol. 4, 269.

In her testimony, Public Staff witness Johnson testified that the Company included instructional advertising that appears to be related to public notices specifically related to Virginia jurisdictional matters. The Public Staff made an adjustment to eliminate those public notices that do not appear to relate to DENC ratepayers. Tr. vol. 6, 26.

For purposes of this proceeding, the Public Staff Stipulation provides for a reduction in the revenue requirement in the amount of $12,000 to reflect a downward adjustment for the advertising costs request in this case. The Commission finds and concludes that the Public Staff Stipulation's treatment of the advertising costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

Executive Compensation

In his direct testimony, witness McLeod testified that the Company made an adjustment to remove 50% of the compensation of the three executives with the highest level of compensation allocated to DENC during the test year. Tr. vol. 4, 267.

In her testimony, Public Staff witness Johnson made an adjustment to also remove 50% of the compensation and benefits of the fourth executive with the highest level of compensation allocated to DENC during the test year. She claimed that executives' duties and compensation encompass a substantial amount of activities related to shareholder interests and therefore some of their compensation and benefits should be borne by shareholders. Tr. vol. 6, 26-28.

For purposes of this proceeding, the Public Staff Stipulation provides that the Stipulating Parties agreed to accept the Public Staff's proposed adjustment to executive compensation costs. The Commission finds and concludes that the Public Staff Stipulation's treatment of the executive compensation costs is appropriate and reasonable in this ease when considered within the context of the Public Staff Stipulation as a whole.

Non-fuel Variable Operation and Maintenance Expense Displacement

In his direct testimony, witness McLeod testified that the Greensville CC began commercial operation in December 2018 and the Company then began incurring ongoing operation and maintenance (O&M) expenses associated with running the facility. The Company proposed an adjustment to annualize non-labor O&M expense based on projected average monthly expenses during 2019. Witness McLeod also explained the Company's adjustment to amortize the deferred costs, including a return on investment, associated with the facility as requested in the Company's petition filed on March 29, 2019, in Docket No. E-22, Sub 566. Witness McLeod stated that the Company is requesting that the incremental costs incurred from the time the facility was placed into service until the time costs will be reflected in the base non-fuel rates approved in this proceeding be deferred and amortized over a three-year period beginning with the effective date of rates approved in this proceeding. Tr. vol. 4, 266, 276.

In her testimony, Public Staff witness Johnson adjusted the non-fuel variable O&M expenses to prevent the inclusion in cost of service of more than an annual level of these types of expenses as the Company made pro forma adjustments to include the full cost of Greensville CC in the cost of service, including adding incremental non-fuel variable O&M expenses to reflect a full year of operations. Witness Johnson testified that, with the addition of Greensville County CC, other plants in DENC's fleet will operate less frequently, and thus incur fewer non-fuel variable O&M expenses. Therefore, the Public Staff adjusted non-fuel variable O&M expenses to prevent the inclusion in cost of service of more than an annual level of these types of expenses. Tr. vol. 6, 29-30.

The Public Staff Stipulation provides for a reduction in the revenue requirement in the amount of $142,000, representing non-fuel variable O&M expense displacement. The Commission finds and concludes that the Public Staff Stipulation's treatment of these non-fuel

O&M costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Lobbying Expenses

In her testimony, Public Staff witness Johnson made an adjustment to remove internal and external lobbying expenses recorded above the line. She explained that she reviewed job descriptions of employees, both registered and non-registered lobbyists, that performed lobbying activities and applied a "but for" test for reporting lobbying costs as used in a State Ethics Commission opinion dated February 12, 2010. As a result, witness Johnson stated that she excluded not only costs for direct contact with legislators, but also costs for other activities preparing for or surrounding lobbying that would not have occurred but for the lobbying itself. Tr. vol. 6, 30-31.

For purposes of this proceeding, the Public Staff Stipulation provides for a reduction in the revenue requirement in the amount of $42,000 to reflect a downward adjustment for the lobbying costs requested in this case. The Commission finds and concludes that the Public Staff Stipulation's treatment of the lobbying costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Uncollectible Expense

In his direct testimony, witness McLeod testified that the Company adjusted its uncollectible expense based on a historical average uncollectible expense rate. Tr. vol. 4, 269.

In her testimony, Public Staff witness Johnson testified that the Company used data from 2014-2018 to calculate its average uncollectibles amount. Public Staff witness Johnson stated that in 2014 the Company changed its write-off and collections policies for customers with medical certifications, and prior to 2014 the Company did not include these customers in its determination of the reserve for uncollectibles. Witness Johnson explained the result of including these customers now created a $12.1 million credit accounting adjustment in 2014, on a total system level, to its reserve for uncollectibles accounts, with a charge to uncollectibles expense, in order to establish an initial reserve for customers with medical certificates. Witness Johnson testified that the Public Staff adjusted this amount by only calculating the average uncollectibles based on 2015–2018 data. Tr. vol. 6, 31-32.

For purposes of this proceeding, the Public Staff Stipulation provides that the Company accepted the Public Staff's proposed adjustment to uncollectibles costs, resulting in a reduction of $238,000 in the Company's revenue requirement. The Commission finds and concludes that the Public Staff Stipulation's treatment of the uncollectibles costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Skiffes Creek

Company witness Bobby McGuire testified on direct that DENC invests in its electric transmission system to ensure reliability and ongoing compliance with the North American Electric Reliability Corporation (NERC) reliability standards and requirements, address load growth, and repair or replace aging infrastructure, and explained that these investments ensure the Company's continued ability to provide safe, reliable, and economical power to all of its customers. He stated that DENC has invested approximately $268 million in electric transmission projects located in North Carolina during the period of 2016–2018. Witness McGuire further explained that the Company's electric transmission system investments completed in Virginia also provide benefits to North Carolina customers. Tr. vol. 6, 366-69.

In his testimony, Public Staff witness David Williamson provided an overview of the Surry-Skiffes Creek 500-kV transmission project that crosses the James River in Virginia, including the need for the project and the regulatory approvals needed for the project from the Virginia State Corporation Commission, the Army Corps of Engineers, and others. Witness Williamson stated that the Public Staff takes the position that the mitigation costs for the project were not incurred for the purpose of constructing or operating the project and do not provide additional benefits to the Company's North Carolina retail customers, so those costs should not be recovered from the Company's North Carolina customers. Specifically, witness Williamson asserted that the mitigation costs, which are predominantly reflected in a Memorandum of Agreement signed by multiple stakeholders that participated in the project's permitting process, should be excluded from the Company's revenue requirement consistent with Commission precedent set in the Company's 2012 Rate Case, Docket No. E-22, Sub 479, involving a disallowance of the incremental costs associated with undergrounding three transmission lines in northern Virginia largely for aesthetic purposes. Tr. vol. 6, 447-61.

In her testimony, Public Staff witness Johnson made an adjustment to remove the costs of the Skiffes Creek project mitigation as explained by Witness Williamson. Tr. vol. 6, 33.

The Public Staff Stipulation provides that the revenue requirement should be reduced in the amount of $153,000 to reflect a downward adjustment for the Skiffes Creek mitigation costs requested in this case. The Commission finds and concludes that the Public Staff Stipulation's treatment of the Skiffes Creek mitigation costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Outside Services

In her testimony, Public Staff witness Johnson testified that the Public Staff reviewed costs for outside services, and that the Public Staff's investigation revealed charges that were related to legal services for certain expenses that were allocated to DENC that should have been directly assigned to other jurisdictions. Witness Johnson stated that DENC ratepayers should be charged only the reasonable costs of providing electric service to North Carolina retail customers. Tr. vol. 6, 33-34.

The Public Staff Stipulation provides that the revenue requirement should be reduced in the amount of $177,000 to reflect a downward adjustment for the outside services costs requested in the case. The Commission finds and concludes that the Public Staff Stipulation's treatment of the outside services costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Mount Storm Fuel Flexibility Project

In his supplemental testimony, Company witness McLeod proposed to defer as a regulatory asset costs associated with the abandoned Coal Yard Fuel Flexibility Project (CYFFP) at the Company's Mount Storm Power Station (Mount Storm) that was canceled due to changing market conditions, decreased power prices, and lower capacity factors, and coal consumption at Mount Storm. The Company abandoned the project in May 2019, resulting in an impairment of construction costs incurred on the project totaling $62.4 million (system-level). Witness McLeod proposed to defer the portion of the CYFFP costs allocable to the Company's North Carolina jurisdiction to be amortized over a three-year period. Tr. vol. 6, 316.

In his testimony, Public Staff witness Thomas provided an overview of the Mount Storm CYFFP, which was undertaken to allow the facility to receive 100% of its coal supplies by rail in the event of problems with truck deliveries. Due to quality differences between truck and rail delivered coal and the emissions limits established by Mount Storm air permits, as well as the specific boiler design characteristics of the Mount Storm units, coal blending facilities were required. Witness Thomas testified that DENC originally planned to construct four coal stacking tubes and a dry coal storage enclosure, and to make significant changes to its rail system, along with supplementary fire suppression systems. He testified that not until the adjustment was included in DENC's supplemental filing did the Public Staff become aware of the project and then have an opportunity to review the costs and underlying analyses. Witness Thomas testified that the Public Staff analyzed the Company's financial analyses used in determining the viability of the CYFFP and expressed concerns with the Company's decision-making with respect to future coal prices used in its analyses, contract negotiations with the local trucked coal supplier, and the projected capacity factor of the Mount Storm facility used in its analyses. He also expressed concerns that significant commitments and associated expenditures with the project appear to have been made prior to completion of detailed engineering work, and relatively little cost-benefit analyses were performed until 2014, three years and $2.1 million into the project. Witness Thomas concluded that based on his review of forecast data in the Company's past IRPs, the Company should have been more aware of market conditions within both the natural gas and coal markets, and the increased risk that the project would not deliver the expected benefits. In addition, he stated that the Public Staff believes that the 2014 cost-benefit analysis justifying the project had significant shortcomings and was not a reasonable or prudent analysis to justify a project that, at the time, had an estimated cost of $116 million. Witness Thomas recommended that expenditures on the CYFFP after the 2014 analysis should be disallowed for a total of $60,179,000 system-wide. Tr. vol. 6, 504-26.

In her testimony, Public Staff witness Johnson made an adjustment to remove certain costs associated with the project as recommended by Public Staff witness Thomas that are allocable to the Company's North Carolina jurisdiction. Tr. vol. 6, 34-35.

The Public Staff Stipulation provides that 50% of the Mount Storm impairment costs should be removed with the remaining portion amortized over 2.75 years. The Commission finds and concludes that the Public Staff Stipulation's treatment of the Mount Storm CYFFP costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

NUG Contract Termination Expense

In his supplemental testimony, witness McLeod testified that the Company had a long-term power and capacity contract with a coal-fired NUG with an aggregate summer generation capacity of approximately 218 MW. Witness McLeod stated that the plant had been, and was expected to remain, generally uneconomical in the PJM Interconnection, LLC (PJM), energy market, and therefore, ran infrequently and was not a key resource for DENC nor does it continue fit within DENC's portfolio of increasingly cleaner generation resources. In May 2019, the Company entered into an agreement and paid $135.0 million to terminate the contract, effective April 2019. Given the magnitude of the termination fee and the significant capacity savings going-forward, witness McLeod proposed to defer the North Carolina jurisdictional portion of the termination fee to be amortized over the original remaining term of the contract (32 months — April 2019 through November 2021).

In her testimony, Public Staff witness Johnson testified that the Public Staff made an adjustment to remove approximately $21.4 million from the NUG contract termination expense payment associated with the Company's early contract termination. Witness Johnson explained that her adjustment accounts for the "net amount" of capacity revenue that the Company will be receiving from the PJM capacity market as well as the estimated replacement power costs that will be incurred as a result of the termination of the contract. Tr. vol. 6, 35-36.

The Public Staff Stipulation provides that the Company accepted the Public Staff's proposed adjustment to the NUG contract termination expense. The Commission finds and concludes that the Public Staff Stipulation's treatment of the NUG contract termination expense is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Impact on Expenses of Changes in Usage and Number of Customers

In her testimony, Public Staff witness Johnson testified that the Company adjusted revenues for the change in kWh sales and the number of customers due to customer growth, changes in usage, and weather normalization, but did not make a corresponding adjustment to recognize the changes in the non-fuel variable O&M expenses, which vary due to the change in kWh sales. She also explained that the Company did not make a corresponding adjustment to customer-related expenses to reflect the change in the number of customers. Witness Johnson adjusted these expenses to reflect the changes in kWh sales and the number of billings proposed by the Company in its customer growth, usage, and weather normalization adjustments. Tr. vol. 6, 36-37.

The Public Staff Stipulation provides that the revenue requirement should be reduced in the amount of $90,000 to reflect updated and corrected customer growth, usage, and weather normalization numbers. The Commission finds and concludes that the Public Staff Stipulation's treatment of these costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

Inflation

In his direct testimony, witness McLeod testified that the Company adjusted O&M expenses in the cost of service not adjusted elsewhere by increasing them with an inflation factor. He explained that the inflation factor was measured as the difference of the Producer Price Index – Finished Goods less Food and Energy (PPI) between the midpoint of the test year and the end of the period from January 1, 2019, to June 30, 2019 (Update Period). Tr. vol. 4, 270.

In his supplemental testimony, witness McLeod updated the inflation adjustment to reflect the actual PPI for June 2019. *Id.* at 313.

Public Staff witness Johnson stated in her testimony that she made additional adjustments in the calculation of the inflation adjustment to reflect the Public Staff's adjustments to the O&M expenses subject to inflation. Tr. vol. 6, 37.

For purposes of this proceeding, the Public Staff Stipulation provides that the revenue requirement should be reduced in the amount of $7,000 to reflect updated data related to inflation. The Commission finds and concludes that the Public Staff Stipulation's treatment of the inflation expense is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Customer Growth, Usage, and Weather Normalization

In his direct testimony, witness McLeod testified that the Company annualized base non-fuel tariff revenues based on projected customer levels and weather-normalized usage as of June 30, 2019. He explained that this adjustment was a net reduction to revenue, primarily reflecting the annualized impact of a return to normal weather on customer usage. In his direct testimony, Company witness Haynes testified that the adjustments for customer growth, increased usage, and weather normalization are incorporated in Form E-1 Item 42.a, and that the methodologies used to calculate these adjustments are consistent with those approved by the Commission in the 2016 Rate Case. Tr. vol. 4, 259, 411.

In their supplemental testimony, witnesses McLeod and Haynes updated the calculations based on actual customer growth and usage during the Update Period. Witness Haynes testified that the weather normalization and usage adjustments should not include Basic Customer Charge revenues in the calculation of the average revenue per kWh applied to the sum of these kWh adjustments. Witness Haynes stated that he made this change in the calculation. *Id.* at 307, 420.

In his second supplemental testimony, witness Haynes presented an additional update to the customer growth and usage adjustments to the level of customers used in the calculation. The update is consistent with how customer levels were calculated in the 2016 Rate Case. In his second supplemental testimony, witness McLeod updated the calculations based on the annualized level of customer usage presented in witness Haynes' second supplemental testimony. *Id.* at 430.

The Public Staff Stipulation provides that the Stipulating Parties agreed to increase the revenue requirement in the amount of $49,000 to reflect the Company's updated and revised kWh sales. The Commission finds and concludes that the Public Staff Stipulation's treatment of these costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Cash Working Capital

In his direct testimony, witness McLeod testified that the Company made an adjustment to its cash working capital (CWC) based on a lead/lag study prepared using calendar year 2017 data. He further explained that the CWC requirement included in the cost of service per books is adjusted based on the adjusted CWC requirement as determined for regulatory purposes. *Id.* at 279.

In his supplemental testimonies, Witness McLeod proposed updates to the CWC adjustment to reflect changes in lead/lag days, and the impacts of the various accounting adjustment revisions and updates to the cost of services. Tr. vol. 4, 297, 329.

Public Staff witness Johnson testified that the Public Staff adjusted CWC under present rates by (1) showing the working capital impact of revenues separate from expenses for presentation purposes, and also (2) reflecting all of the other Public Staff adjustments. Witness Johnson also adjusted CWC for the effect of the Public Staff's proposed revenue decrease. Tr. vol. 6, 38-39.

For purposes of this proceeding, the Public Staff Stipulation provides that the revenue requirement should be reduced in the amount of $83,000 and $282,000 to reflect changes in CWC under present and proposed rates, respectively. The Commission finds and concludes that the Public Staff Stipulation's treatment of these costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

DES Office Building

In his direct testimony, witness McLeod testified that during the second quarter of 2019, the Company planned to occupy a new office building, 600 Canal Place, and made an adjustment to annualize the amount of costs for DENC's direct occupancy of the new building, as well as DENC's billable portion of expenses from DES based on DES' existing methodology to bill its office space and equipment expenses to affiliates. He explained that the Company planned to cease occupying its existing office space after the move and the adjustment reflects the net effect of the increased annual expenses between the two offices. Tr. vol. 4, 267-68.

In his supplemental direct testimony, witness McLeod testified that, at the time of the of the Application, occupation of 600 Canal Place by DENC and DES employees was expected to begin during the second quarter of 2019. Witness McLeod explained that DES and the Company began occupying the new building in July 2019 and DES will begin making lease payments in August 2019. The Company's adjustment updated the new lease expense budget for calendar year 2019 and witness McLeod stated that the expense will be updated again in September 2019 after the actual lease payment is incurred for August 2019. Witness McLeod's second supplemental testimony updated this accounting adjustment based on the actual corporate-level costs for the month of August 2019, the month in which the lease payments commenced. Tr. vol. 4, 312, 331.

In her testimony, Public Staff witness Johnson testified that the Public Staff was awaiting additional documentation pertaining to the Company's adjustment to reflect the new office building. Witness Johnson explained that the Public Staff will need additional time to review the adjustments once filed by the Company as they relate to the new office building. *Id.* at 40-41.

For purposes of this proceeding, the Public Staff Stipulation provides that the revenue requirement should be reduced in the amount of $720,000 to reflect the updated, actual costs of the Company's new office building. The Commission finds and concludes that the Public Staff Stipulation's treatment of the office building costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Depreciation

In his direct testimony, witness McLeod testified that the Company made an adjustment to annualize the depreciation expense based on projected plant in service as of June 30, 2019, and the composite depreciation rate from the Company's most recent depreciation study. *Id.* at 274.

In his supplemental testimony, witness McLeod updated the depreciation expense based on actual plant in service at the end of the update period. Tr. vol. 4, 317.

In her testimony, Public Staff witness McCullar testified that she participated in field visits of several DENC facilities or project locations, analyzed the Company's most recent depreciation study, and presented the Public Staff's proposed depreciation rates. Witness McCullar's Table One provides a comparison of annual deprecation accrual amounts as proposed by the Company versus as proposed by the Public Staff. The table indicates that the Public Staff and the Company are aligned with respect to steam production plant, nuclear production plant, hydraulic production plant, combined cycle production plant, simple cycle production plant, and general plant. The two parties differed, however, with respect to solar production plant, transmission plant, and distribution plant. Witness McCullar explained that for solar production plant, the Public Staff used updated depreciation schedules that changed the probable retirement year for several solar facilities from 2041 to 2051. Public Staff witness McCullar also explained that the differences in transmission plant and distribution plant depreciation as a difference between the Public Staff's and the Company's proposed future net salvage accrual amounts, as the Public Staff proposed less accelerated future net salvage amounts than the Company. Tr. vol. 6, 476-94.

For purposes of this proceeding, the Public Staff Stipulation provides that the Public Staff accepted the Company's proposed depreciation rates as filed in its Application. Subject to the qualifications and direction provided in Findings of Fact Nos. 56-58 and the discussion thereunder relating to the costs of removal portion of depreciation allowance, in all other respects the Commission finds and concludes that the Public Staff Stipulation's treatment of the depreciation costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Retirement of Cold Reserve Units

In his direct testimony, Company witness Mitchell testified that, in an effort to reduce costs, uneconomical units that were previously placed in a cold reserve state and are not currently operating will be retired by the end of March 2019. According to witness Mitchell, these older, less efficient units are unable to compete in the current energy market and have been displaced by cleaner burning natural gas facilities, as well as utility-scale solar. Witness Petrie explained in his direct testimony that ten of these units were older, less efficient units that were placed in a "cold reserve" state in 2018. These units included Bellemeade Power Station, Bremo Power Station Units 3 and 4, Chesterfield Power Station Units 3 and 4, Mecklenburg Power Station Units 1 and 2, Pittsylvania Power Station, and Possum Point Power Station Units 3 and 4, all of which were retired from service effective March 31, 2019. Witness Petrie also testified that the Company plans to retire Possum Point Unit 5 on May 31, 2021.

In his supplemental testimony, witness McLeod explained that, as a result of these early retirements, the Company recorded an impairment charge of $307.1 million, representing the remaining net book value of the units. Related balances in construction work in progress and materials and supplies inventory were written-off as well. Witness McLeod proposed that the Company amortize the impairment cost for the ten units formerly in cold reserve over a ten-year levelized basis and the materials and supplies inventory over a three-year period. He also proposed eliminating the O&M expense and materials and supplies inventory for the ten units formerly in cold reserve. Finally, witness McLeod proposed reestablishing the Possum Point Unit 5 net book value and depreciation expense for ratemaking purposes as the unit has not yet been physically retired from service. He requested that any costs incurred during the decommissioning of these facilities after the update period be deferred for review in the Company's next base rate case, consistent with the treatment of decommissioning costs for the Chesapeake Energy Center in the 2016 Rate Case. Tr. vol. 4, 302-04, 348.

The Commission notes that it appears from the evidence presented that the amount of the impairment charge recorded by the Company on account of the units decommissioned effective March 31, 2019, does not include costs of remediation and closure of coal ash management units associated with the units in cold reserve. Accordingly, the Commission finds and concludes that the Company's treatment of costs associated with the retirement of cold reserve units is appropriate and reasonable in this case so far as it goes. The Company should consider the Commission's Findings of Fact Nos. 56-58 and the discussion thereunder relating to the costs of removal portion of depreciation allowance when recording impairment charges due to early retirements in the future.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27-31

The evidence supporting these findings of fact and conclusions is found in the Company's verified Application and Form E-1, the exhibits and testimony of Company witnesses McLeod and Haynes, the exhibits and testimony of Public Staff witness Boswell, the exhibits and testimony of CIGFUR witness Phillips, the Public Staff Stipulation, and the entire record in this proceeding.

Summary of the Evidence

In his direct testimony, DENC witness McLeod described the Tax Act and the primary elements of the Tax Act that impact DENC, including a reduction in the federal corporate income tax rate from 35.00% to 21.00%. Witness McLeod noted that the Commission initiated a new generic proceeding in January 2018, in Docket No. M-100, Sub 148 (Sub 148), to address how North Carolina utilities should adjust their North Carolina jurisdictional cost of service and rates in response to the Tax Act. Witness McLeod testified that by order dated January 3, 2018 in Sub 148 the Commission directed certain utilities, including DENC, to collect the federal corporate income tax expense component of rates on a provisional basis beginning January 1, 2018, pending a final order from the Commission. Witness McLeod described the filings and orders in Sub 148 and explained that DENC implemented a Commission-approved rate reduction to address certain impacts of the Tax Act, as ordered by the Commission in its October 5, 2018 Order Addressing the Impacts of the Federal Tax Cuts and Jobs Act on Public Utilities, issued in Sub 148. Witness McLeod testified that this included an annual revenue reduction of $14.3 million due to a base rate adjustment to reflect the lower federal corporate income tax rate, and approval of a one-time customer bill credit to reflect the return of money collected provisionally under the January 3, 2018 Order for income taxes at the higher tax rate through existing base rates billed since January 1, 2018. The one-time customer bill credits were reflected on customers' bills beginning in the April 2019 billing period for amounts collected provisionally from January 1, 2018 through March 2019.

Witness McLeod testified that for purposes of federal EDIT, the Company established an overall regulatory liability and began amortizing plant-related federal EDIT on its books and records at a system level as a reduction to income tax expense with an effective date of January 1, 2018. Witness McLeod explained that this amortization is being deferred to a regulatory liability account in accordance with the Commission's October 5, 2018 Order. Witness McLeod provided a general overview of federal EDIT and explained that the predominant amount of federal EDIT is associated with utility property depreciation and related book-tax timing differences, which are subject to the Internal Revenue Code's (IRC's) normalization rules. Witness McLeod noted that this EDIT is referred to as "protected" and the Company is required to use the average rate assumption method (ARAM) for purposes of amortizing such EDIT. Witness McLeod provided the federal EDIT balances as of December 31, 2017, at a system level and the portion allocable to the North Carolina retail jurisdiction of $94.1 million (revised to $94.7 million in witness McLeod's supplemental testimony) for plant-protected, plant-unprotected, and non-plant unprotected.

Witness McLeod testified that for ratemaking purposes, the Company has proposed that the effective date of federal EDIT amortization begin on January 1, 2018. He further explained that because the Company is proposing to implement new rates beginning November 1, 2019, that the federal EDIT amortization attributable to the 22-month period of January 1, 2018, through October 31, 2019, would be credited to customers through a one-year decrement rider, Rider EDIT, of $6,909,000. Finally, witness McLeod testified that for periods thereafter, the Company's fully adjusted cost of service includes the income tax benefit arising from annual federal EDIT amortization during the test period, thereby incorporating a going-level of federal EDIT amortization in base non-fuel rates. Witness McLeod proposed an ARAM method to amortize plant-related federal EDIT (both protected and unprotected) and a 30-year amortization period for non-plant, unprotected federal EDIT. Witness McLeod presented the proposed annual amount of federal EDIT amortization for the North Carolina jurisdiction of $2.7 million. Witness McLeod explained that the base non-fuel revenue requirement reflects this amortization providing the customers with an annual revenue benefit of approximately $3.6 million ($2.7 million/74% retention factor). Tr. vol. 4, 290-91.

In DENC witness Haynes' direct testimony, he explained the Company's proposal that the Rider EDIT credit should be allocated to customer classes based upon North Carolina basic (non-fuel) rate revenue annualized based upon current rates for 2018. Witness Haynes testified that the decrement rate will be applied to customer usage beginning with the effective date of the rider and will be in effect for 12 months. Witness Haynes proposed that, prior to the tenth month from the effective date of the rider, the Company will provide an analysis to the Public Staff to evaluate if the total rider credit will be provided at the end of the 12 months. Witness Haynes explained that if there is a deviation between the total rider credit and the projected credit provided to customers, the Company and the Public Staff will work together to develop an adjustment to the Rider EDIT to minimize the deviation over the remaining months of Rider EDIT being in effect. Tr. vol. 4, 401-02.

In his supplemental testimony, witness McLeod summarized DENC's corrections to the allocation of system-level federal EDIT balances and amortization to the North Carolina jurisdiction resulting from revisions to DENC's cost of service study presented by witness Miller. Witness McLeod noted that as a result of the corrections, the North Carolina jurisdictional federal EDIT balance was revised from $94.1 million to $94.7 million. Witness McLeod explained that the total Rider EDIT rate credit, as revised, reflects a slight $1,000 increase from $6,909,000 to $6,910,000. Tr. vol. 4, 296-97, 325-26.

In his testimony, CIGFUR witness Phillips acknowledged DENC's proposal to credit to customers through a one-year rider the federal EDIT amortization attributable to the period January 1, 2018 through October 31, 2019 and stated that EDIT are overpayments that should be returned as soon as possible. Tr. vol. 6, 431.

In her direct testimony, Public Staff witness Boswell recommended three adjustments to the Company's proposed treatment of federal EDIT. First, witness Boswell stated that she agreed with the Company's proposed ARAM utilization for federal protected EDIT but could not calculate this amortization due to a lack of a breakout between protected and unprotected EDIT. Witness Boswell recommended that the Commission require the Company to file schedules illustrating this breakout. Second, witness Boswell stated that she disagreed with the Company's adjustment to include a portion of unprotected EDIT labeled as "plant-unprotected" to be recovered utilizing the ARAM calculation. Instead, witness Boswell recommended including the "plant-unprotected" balance with the non-plant unprotected EDIT and collecting the balance on a levelized basis over a five-year period. Finally, witness Boswell testified that the entire unprotected EDIT balance should be removed from rate base and placed in a rider to be collected from ratepayers over a five-year period. Witness Boswell testified that the Public Staff does not, in theory, object to the Company's proposal to flow back federal protected and unprotected amortization since January 1, 2018, as a one-year levelized rider. Tr. vol. 6, 440-43.

DENC and the Public Staff reached a stipulation on all of the Tax Act-related issues as outlined in Section VIII.A of the Public Staff Stipulation, wherein they agreed that DENC shall implement Rider EDIT to allow for recovery of federal EDIT of $1.2 million on a levelized basis over a two-year period, with a return. The Public Staff Stipulation notes that the $1.2 million is comprised of: (1) the amortization of all unprotected federal EDIT totaling approximately $8.0 million partially offset by (2) the refund of approximately $6.8 million associated with federal

EDIT amortization attributable to the 22-month period of January 1, 2018 through October 31, 2019. The Public Staff Stipulation also states that the appropriate revenue level of EDIT to be recovered by DENC is presented on Settlement Exhibit II and that DENC will implement Rider EDIT as described in the stipulation testimony of DENC witness McLeod.

Further, the Public Staff Stipulation states in Section IV.E that the Stipulating Parties agree to reduce the revenue requirement in the amount of $287,000 to reflect the removal of federal unprotected EDIT from rate base, which will be recovered by the Company through a rider as discussed in Section VIII.

In his Stipulation testimony, witness McLeod testified that the Stipulating Parties agreed that the Company would implement Rider EDIT to allow for recovery by DENC of federal EDIT of $1.2 million, comprised of the amortization of all unprotected federal EDIT totaling $8.0 million, partially offset by the refund to ratepayers of approximately $6.8 million associated with federal EDIT amortization attributable to the 22-month period January 1, 2018, through October 31, 2019. Tr. vol. 4, 340.

Discussion and Conclusions

In Ordering Paragraph No. 6 of its October 5, 2018 Order in Sub 148, the Commission ordered:

> That excess deferred income taxes related to the decrease in the federal corporate income tax rate to 21% under the Tax Act for Cardinal, DENC, DEP, Piedmont, and PSNC, as appropriate, shall be held in a deferred tax regulatory liability account until they can be addressed for ratemaking purposes in each utility's next general rate case proceeding or in three years, whichever is sooner. These amounts will ultimately be returned to customers . . . . Therefore, the Commission concludes that if Cardinal, DENC, DEP, Piedmont or PSNC have not filed an application for a general rate case proceeding by October 5, 2021, each Company shall file its proposal by that date to flow back to its ratepayers both the protected and the unprotected EDIT generated due to the Tax Act. The federal EDIT flow back proposal should include all workpapers that support the proposed calculations. . . . These utilities are hereby required to maintain the deferred tax regulatory liability account previously established and shall not begin amortization of amounts recorded in such accounts pending further order of the Commission.

This proceeding is the first general rate case filed with the Commission by DENC since the October 5, 2018 Order was issued. DENC has complied with the Commission's directive by addressing the Tax Act issues in this rate case that was filed before October 5, 2021. The Company has also complied with the Commission's directive not to begin amortization of North Carolina jurisdictional federal EDIT until further order of the Commission. DENC meets this requirement, given the Company's proposal to begin amortization on January 1, 2018, by proposing to credit the amortization during the 22-month period from January 1, 2018, through October 31, 2019, the effective date of rates in this case, to customers through a decrement rider, Rider EDIT. In addition, for periods thereafter, the Company's cost of service for ratemaking purposes includes the income tax benefit arising from annual federal EDIT amortization during the test period, thereby incorporating a going-level of federal EDIT amortization in base non-fuel rates.

As outlined in Public Staff witness Boswell's testimony, the Public Staff recommended including the "plant-unprotected" federal EDIT balance with the federal unprotected EDIT and collecting the balance from ratepayers through an increment rider to be collected from ratepayers over five years on a levelized basis, with carrying costs. Witness Boswell testified that this recommendation is consistent with previous recommendations of the Public Staff.

The Stipulating Parties agreed that the Company shall implement Rider EDIT to allow for recovery of certain federal EDIT. The Public Staff Stipulation provides that the appropriate level of federal EDIT to be recovered by the Company in this case is $1,214,000 (on a pre-income tax basis), which includes: (1) the amortization of all unprotected federal EDIT totaling approximately $8.0 million partially offset by (2) the refund to ratepayers of approximately $6.8 million associated with federal EDIT amortization attributable to the 22-month period January 1, 2018 through October 31, 2019. Rider EDIT will be implemented to recover certain federal EDIT from ratepayers over a two-year period on a levelized basis, with a return. As reflected on Settlement Exhibit II, Schedule 2, the appropriate amount to be recovered from customers is a total of $1,299,369. Rider EDIT should be calculated and reviewed using the methodology presented in the testimony of DENC witness Haynes.

On September 25, 2019, the Commission issued an Order Requesting Additional Information and ordered that the Public Staff make a filing providing an explanation of why DENC's total unprotected EDIT has a debit balance, as the Commission has not previously seen a debit balance in its consideration of EDIT issues related to the Tax Act. On October 7, 2019, the Public Staff filed a response to this request. The response referenced the testimony and exhibits of Company witness McLeod which provided details regarding the Company's balance of unprotected federal EDIT. Specifically, the Public Staff noted that witness McLeod's testimony and exhibits demonstrate that the largest debit balance for non-plant unprotected EDIT related to pension benefits. The Public Staff stated that it reviewed the causation of the debit balance for the aforementioned account and determined that the debit balance was due to the status of funding for the Company's pension plan. The Public Staff further stated that as of December 31, 2017, the Company's projected benefits obligation from its pension plan was larger than the amount that had been funded for the plan, resulting in a net pension liability on the Company's books. The Public Staff observed that this in turn resulted in a deferred tax asset on the Company's books, and thus an EDIT asset. The Public Staff stated that it submitted a data request to DENC on this matter. The Public Staff maintained that after further discussions with DENC in regard to its response, and in recognition of the fact that different companies may well calculate the split between plant-related protected and unprotected EDIT using different analyses and methods, the Public Staff accepted the Company's division of plant-related EDIT between protected and unprotected components, which results in the unprotected portion having a relatively small debit balance.

Based on all of the evidence of record in this case, the Commission finds that it is appropriate to accept the Public Staff Stipulation concerning the Tax Act issues. The ratemaking treatment of federal EDIT, including Rider EDIT presented in the Public Staff Stipulation, is just and reasonable to all parties in light of all the evidence presented. In reaching its decision, the Commission gives substantial weight to DENC witness McLeod's stipulation testimony.

Further, although not specifically outlined in the Public Staff Stipulation, it is appropriate that in this proceeding DENC's fully-adjusted cost of service includes the income tax benefit arising from the annual amortization of federal protected EDIT during the test year, thereby incorporating a going-level of federal protected EDIT amortization in base non-fuel rates, in accordance with the IRC's normalization rules.

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

The evidence supporting these findings of fact and conclusions is found in the verified Application; the direct testimony and exhibits of Company witnesses Petrie and Haynes; the supplemental testimony of witnesses Petrie, Haynes, and McLeod; the additional supplemental testimony of witness Haynes; the testimony and exhibits of Public Staff witnesses Floyd and Johnson; the Public Staff Stipulation; and the entire record in this proceeding.

Summary of the Evidence

In his direct testimony, Company witness Petrie presented an estimate of DENC's adjusted system fuel expense for the period July 1, 2018 – June 30, 2019, of $1.803 billion, which was used by Company witness Haynes to estimate the anticipated reduction in the fuel factor rate. He also estimated a cumulative fuel under-recovery position for the 12-month test period ending June 30, 2019, of approximately $1–3 million, and described DENC's forecasted fuel expense over-recoveries for the second half of 2019 and how those over-recoveries could offset the expected under-recovery as of June 30, 2019. Tr. vol. 6, 345-50.

Witness Haynes calculated the projected normalized North Carolina jurisdictional average fuel factor and differentiated that rate by voltage for each class. These calculations were consistent with the methodologies used in the Company's 2018 fuel case, except that he updated the class expansion factors for 2018. Witness Haynes also presented DENC's projected EMF and total projected change in its fuel factor to be filed in its 2019 fuel proceeding. Tr. vol. 4, 397-400.

Witness Petrie also testified that the Company evaluated the current Marketer Percentage calculation and updated the calculation based on the PJM State of the Market Reports for 2017 and 2018 using the same averaging method applied in the 2018 Fuel Case and the 2016 Rate Case. Using this method, witness Petrie calculated an updated Marketer Percentage of 71%. Tr. vol. 6, 345-50.

In his direct testimony, witness McLeod testified that adjustments to purchased energy expenses reflect an updated Marketer Percentage of 71% supported by Company witness Petrie. Witness McLeod stated that the base fuel rate revenue requirement in the supplemental filing will reflect the 71% Marketer Percentage. Tr. vol. 4, 245.

In his supplemental testimony, Witness Petrie presented an updated adjusted total system fuel expense for the 12-month period ending June 30, 2019, of $1.78 billion, based on the 71% Marketer Percentage proposed in the Company's Application. Tr. vol. 6, 355-56.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

In his direct testimony, Company witness Haynes testified that while the Company's fuel factor is adjusted annually by the Commission between general rate cases, the Commission also resets the Company's base fuel factor in each base rate case as required by subsection (f) of the North Carolina fuel factor statute, N.C.G.S. § 62-133.2. Company witness Haynes proposed to initially set a placeholder base fuel rate for each class based on the fuel factor approved in the Company's 2018 fuel adjustment case, Docket No. E-22, Sub 558 (2018 Fuel Case). He further testified to the Company's proposal to set Rider A – Fuel Cost Rider to zero beginning November 1, 2019, and to use the fuel rate as approved in the 2018 Fuel Case, differentiated by class, as the placeholder base fuel rate in each of the rate schedules. Witness Haynes stated that the Company planned to update the placeholder base fuel rate after the Company filed its annual fuel factor application in August 2019. Tr. vol. 4, 397-98.

In his supplemental testimony, Witness Haynes updated the placeholder base fuel rate and proposed a new rider, decrement Rider A1, which the Company planned to file in its August 2019 fuel factor application. Witness Haynes testified that because the Company was anticipating an over-recovery of fuel expenses for the period of July 2019 to December 2019, and to mitigate the effect of the November 1, 2019, non-fuel base rate increase on customers' rates, the Company was proposing to implement a three-month decrement rider, Rider A1. Witness Haynes testified that Rider A1 would allow for a seamless, no impact transition of total fuel rates between November 1, 2019, and February 1, 2020, based on the Company's anticipated fuel factor filing. Finally, he explained that the Company anticipated making an additional supplemental update in this proceeding to calculate the revised base fuel rates by customer class using the information in the Company's August 2019 fuel factor application. Tr. vol. 4, 416, 423-24.

In his additional supplemental testimony, witness Haynes used the updated adjusted total system fuel expense presented in the Company's 2019 fuel factor filing to calculate a jurisdictional average base fuel factor of 2.092¢/kWh. He also used the revised Rider A rate of zero, to be effective on November 1, 2019, consistent with the Company's 2019 fuel factor filing. Finally, witness Haynes explained that the amount used for decrement Rider A1 was based on an estimation that the Company will over-recover fuel expenses from July through December 2019 by approximately $11.8 million, with the rider being the difference between the proposed February 1, 2020, Fuel Rider B EMF Rate and the current EMF Rider B rates that became effective on February 1, 2019. Witness Haynes stated that including the proposed base fuel rate, the proposed Fuel Rider A re-set to 0.000¢/kWh, the proposed Rider A1 rates, and the present EMF Rider B, the Company proposed to implement a jurisdictional average total fuel rate of 2.105¢/kWh on November 1, 2019, a decrease of 0.425¢/kWh compared to the present jurisdictional average total fuel rate of 2.530¢/kWh. Tr. vol. 4, 428-31.

Public Staff witness Floyd testified the Public Staff did not have any concerns with the Company's proposed fuel rates for purposes of this proceeding and that the Public Staff would address any concerns with fuel rates in the 2019 Fuel Case proceeding in Docket No. E-22, Sub 579. Witness Floyd also stated that the Public Staff did not oppose implementing the Company's proposed total fuel rate as part of the interim rates on November 1, 2019, along with the proposed decrement Rider A1. Tr. vol. 6, 81-83.

In her testimony, Public Staff witness Johnson adjusted the fuel clause expense to reflect the base fuel rate and Rider A as set forth in the additional supplemental testimony of DENC witness Haynes, and recommended by Public Staff witness Floyd, subject to the outcome of the Company's currently ongoing fuel proceeding in Docket No. E-22, Sub 579. Witness Johnson stated that this adjustment resulted in a decrease of $2.155 million from the fuel expense originally included in the Company's Application. Tr. vol. 6, 39.

Section V.A of the Public Staff Stipulation provides that a decrease of $2.155 million in the Company's base fuel revenue requirement, incorporating the base fuel rate and Rider A as set forth in the additional supplemental testimony of Company witness Haynes and recommended by Public Staff witness Floyd, was appropriate to be included in the Company's base rates, subject to any adjustment based on the outcome of the Company's ongoing 2019 Fuel Factor proceeding. The Stipulating Parties also agreed that decrement Rider A1, equal to (0.375¢/kWh) on a jurisdictional basis, is appropriate to become effective on November 1, 2019.

Discussion and Conclusions

Based on all the evidence in this proceeding, the Commission finds and concludes that the stipulated jurisdictional average base fuel factor of 2.092¢/kWh, including the regulatory fee, is just and reasonable for DENC and ratepayers in this case. Further, the jurisdictional average base fuel factor should be differentiated between customer classes on a voltage basis, as provided on Company Additional Supplemental Exhibit PBH-1, Schedule 1, Page 2.

Finally, the Commission notes that no party opposed the Company's proposed Marketer Percentage. Based on all of the evidence in this proceeding, the Commission finds and concludes that effective February 1, 2020 a Marketer Percentage of 71%, should be applied to appropriately determine the fuel cost component of energy purchased for which the fuel cost is unknown, and shall remain in effect until approval of a new Marketer Percentage in the Company's 2021 fuel factor filing, or next general rate case, whichever is earlier.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 35-39

The evidence supporting these findings of fact and conclusions is found in the verified Application and exhibits, the Public Staff Stipulation, and the testimony of Company witnesses Miller and Haynes, Public Staff witness Floyd, Nucor witnesses Thomas and Wielgus, CIGFUR witness Phillips, and the entire record in this proceeding.

Summary of the Evidence

The Company's Application, as supported by Company witnesses Miller and Haynes, used the Summer/Winter Peak and Average (SWPA) cost of service methodology to allocate production and transmission plant costs for both the North Carolina jurisdiction and the North Carolina retail customer classes. The SWPA method recognizes two components of providing service to customers – peak demand and average demand – when determining the responsibility for costs of production and transmission plant and related expenses. The peak demand component takes into account the hour when the load on the system is highest during both the summer months and the winter months. The average demand component recognizes that there is a load incurred by the system over the course of all hours during the year. The average demand is determined based upon the total energy provided to the customers during the year divided by the total number of hours in the year. The average component is then weighted by the system load factor, and the peak component is weighted by 1 minus the system load factor. The load factor is calculated by taking the Company's actually experienced average demand divided by its actually experienced peak demand during the test year.

Witness Miller explained that DENC developed and presented in its Form E-1, Item 45, the "per books," annualized, and "fully-adjusted" jurisdictional and customer class cost of service studies for the test year ended December 31, 2018. Witness Haynes explained that in developing the SWPA cost of service study (COSS), the Company also made two adjustments in the course of calculating the SWPA allocation factors. The first is an adjustment to the Company's recorded summer and winter peaks to recognize and add back the kW generated by NUGs interconnected to DENC's distribution system that are not included in those values. Witness Haynes testified that this adjustment was approved by the Commission in the Company's 2016 Rate Case. The second is an adjustment to remove the demand and energy requirements of three customers, one wholesale customer, NCEMC, and two large industrial customers in the Company's Virginia jurisdiction, for whom the obligation to provide generation service has ended or will end during 2019. Tr. vol. 4, 374.

Witness Miller testified that the objective of jurisdictional and customer class cost of service studies is to determine the allocation of a share of the system's revenues, expenses, and plant related to providing service across multiple jurisdictions. Certain items can be assigned directly to the jurisdiction and classes based on the utility's records, but other items are not directly assignable and must be allocated. Witness Miller stated that in this proceeding, the Company allocated its production and transmission plant and expenses using the SWPA cost of service methodology. He noted that the Commission has approved DENC's use of the SWPA method in DENC's last six general rate cases, dating back to 1983, including the 2016 Rate Case. Witness Haynes testified that the SWPA allocation method is consistent with the manner in which DENC plans and operates its system. Specifically, the "Summer and Winter" peak component recognizes the total level of generation resources necessary to serve the system peaks, while the average component recognizes the type of generation serving customers' energy needs year-round. *Id.* at 371-73, 502-10.

Witness Haynes also emphasized that use of a single peak or other peak-only methodology could allow certain customer classes that have zero demand during the peak hour(s) of the year to fully avoid responsibility for production plant costs. Witness Haynes explained that a common example is streetlights that normally do not operate during peak hours. Witness Haynes also highlighted the NS Class as another example unique to DENC's North Carolina jurisdictional load. Witness Haynes explained that Nucor, the only customer in the NS Class, has an average annual demand throughout the year of approximately 106 MW, while Nucor's average of its summer (July 2, 2018) and winter (January 7, 2018) coincident peak demands is approximately 42 MW. Witness Haynes explained that without recognizing an average component in the cost allocation, this customer class would "pay" for only 42 MW and escape cost responsibility for an average of 64 MW for the rest of the year (i.e., the average demand of 106 MW less the allocated demand of 42 MW). Witness Haynes explained that by recognizing both the energy needed to serve load at the peak hour, as well as energy consumed throughout the year, the SWPA method allocates some portion of these system costs to all customers, including those customers that can reduce their peak demand and those that may not place a demand on the system during the respective summer and winter peak hours. Such customers still use and receive the benefit of the Company's investments in production assets by paying lower energy costs, specifically fuel costs, during all other hours. *Id.* at 371-74.

Public Staff witness Floyd agreed with the Company's use of the SWPA cost of service methodology in this proceeding because it appropriately allocates the Company's production plant costs in a way that most accurately reflects the Company's generation planning and operation. He testified that unlike other methodologies that allocate all of the production plant costs based on a single coincident peak or on a series of monthly peaks, the SWPA methodology recognizes that a portion of plant costs, particularly for base load generation, is incurred to meet annual energy requirements throughout the year and not solely to meet peak demand at a particular time. Witness Floyd also stated that the Public Staff agrees with DENC's proposed adjustments to the COSS as appropriately recognizing the impact of distribution connected NUGs and the removal of wholesale contract load in 2020 on DENC's utility system. Tr. vol. 6, 68-72.

CIGFUR witness Phillips testified that the SWPA method is inconsistent with both DENC's method of planning for future capacity requirements, and the increase in the portion of its generating mix represented by natural gas, as outlined in its 2018 IRP. Witness Phillips also claimed that the SWPA method over-allocates cost to large, high load factor customers without a symmetrical fuel cost allocation. Witness Phillips advocated for the use of the Summer/Winter Coincident Peak (S/W CP) cost of service methodology as consistent with system planning and cost causation principles, arguing that the S/W CP corrects over-allocations of costs to large, energy intensive industrial customers, such as those on the Company's Schedule 6VP. *Id.* at 422-25.

Nucor witness Wielgus did not recommend that the 1-Coincident Peak (1-CP) methodology be used in the cost of service study in this proceeding, but he did recommend that the Commission examine in a formal proceeding whether using a 1-CP or 5-CP method instead of the Company's proposed SWPA would be most appropriate for DENC given the way that PJM uses coincident peaks and that Duke Energy conducts its cost of service studies for its North Carolina jurisdiction. Witness Wielgus argued that the SWPA fails to properly recognize the system's need for generation and is not consistent with the Company's primary need for generation capacity, which is to serve its annual peak demand. Witness Wielgus also argued that the SWPA method fails to recognize the system benefits associated with the NS Class. In particular, witness Wielgus noted that Nucor's facility comprises approximately 20% of the Company's load, has a high load factor that is beneficial to the Company's system operations and corresponding costs, and the service to Nucor is not firm and Nucor must curtail if called upon to do so. Witness Wielgus calculated a value of the capacity that is avoided when Nucor is curtailed based on its peak load of 172 MW and its load during the summer and winter peak hours of 42 MW and claimed that if Nucor were a firm customer, the Company would have to secure an additional 129 MW of capacity every day of the year at an annual cost of $5.7 million. *Id.* at 378-400.

Nucor witness Thomas presented two variations on the allocation of production costs using a 1-CP model and a re-weighted Summer/Winter Peak and Average (reweighted SWPA) model. Witness Thomas explained that for the 1-CP model he replaced the SWPA allocator with the single highest coincident peak demand, which in this proceeding was the winter peak demand net of North Anna. In the reweighted SWPA, witness Thomas explained that he used a 60% weight for the summer/winter peak demand component and a 40% weight for the average demand (energy) component. Witness Thomas concluded that under the 1-CP scenario, Nucor would have a relative rate of return (ROR) index before the revenue increase of 3.10, which is significantly higher than the 0.84 index computed by the Company under its SWPA scenario. In the reweighted SWPA, Nucor has a relative ROR of 1.20 before the revenue increase. Finally, he explained that to achieve a ROR index of 0.80 for Schedule NS, as the Company's SWPA methodology does, Nucor's base revenue would have to decrease by nearly $10.5 million under the 1-CP scenario and $2 million under the reweighted SWPA scenario. *Id.* at 404-08.

Company witness Haynes extensively addressed and rebutted the cost of service arguments of witness Phillips on behalf of CIGFUR and witness Wielgus on behalf of Nucor in his rebuttal testimony. Witness Haynes explained that the SWPA method reasonably and appropriately recognizes the two components of providing service to customers, peak demand and average demand, and is consistent with the manner in which the Company's planning department plans for and meets DENC's system needs, taking into consideration the need both to meet peak demands and to provide resources that can be operated to serve customers throughout the year. The Company's SWPA cost of service study followed the same approach for Schedule NS (as well as all other classes) used in the cost of service studies filed and approved in DENC's three most recent rate cases, Docket No. E-22, Sub 532 in 2016, Sub 479 in 2012, and Sub 459 in 2010. Specifically, as described by Company witness Haynes, the Company used both a summer and winter peak demand for the NS Class that reflected Nucor's measured demand and recognized the interruptible nature of Nucor's arc furnace pursuant to the confidential terms and conditions of the Company's contract with Nucor. The 42 MW of peak demand assigned to the NS Class represents the average of the winter and summer peaks of the NS Class at the time of the test year system winter and summer peaks. These peak demands were used to develop the production plant and transmission related demand allocation factors.

Witness Haynes explained that the "Summer and Winter" peak component recognizes the total level of generation resources necessary to serve the system peaks, while the average component recognizes the dispatch of different types of generation providing the system with low cost energy year-round. Witness Haynes pointed to the Company's recent addition of the 1,588 MW Greensville County CC, as well as the Company's historical investments in its baseload fleet as production-related plant operated throughout the year to provide baseload energy to the Company's customers. Witness Haynes also specifically pointed to the Company's investment in nuclear plant at the end of 2018 that represented approximately 26% of the total production plant invested. He also reiterated the Commission's consistent support for the Company's continued use of the SWPA methodology as the proper method to assign production plant costs to all customer classes, including the Schedule NS Class. Tr. vol. 4, 436-47.

Witness Haynes testified that the S/W CP methodology advocated by CIGFUR witness Phillips is not reasonable or appropriate for DENC because its reliance on only the two hours of

DENC's summer and winter peaks is inconsistent with the way DENC plans and operates its system to meet the system peaks and deliver low cost energy throughout the year. He also explained that use of the S/W CP would result in a significant shift of costs to the residential class. *Id.* at 437-38.

Witness Haynes also testified that witness Wielgus' recommendation that the Commission examine in a formal proceeding whether using a 1-CP or 5-CP method instead of the SWPA would be most appropriate for DENC is misplaced. Witness Haynes argued that such a method would increase the total North Carolina jurisdictional revenue requirement and significantly shift costs to the residential class while benefitting Nucor and the LGS and 6VP classes. Witness Haynes testified that regardless of the methodology approved by the Commission for use by Duke Energy, it is appropriate for the Commission to consider the usage characteristics of customers and the generation system's planning and operation for each utility to determine an appropriate allocation method, rather than not uniformly applying a particular method to all utilities. *Id.* at 437-66.

With respect to witness Wielgus' recommended modifications to the weighting of the peak demand and average components in the SWPA method as proposed by the Company, witness Haynes stated that the modifications are not consistent with the way customers use the Company's production and transmission systems and would result in a shift in cost responsibility from Nucor and other non-residential classes to the residential class, resulting in a higher increase in rates for residential customers than proposed by the Company. *Id.*

Witness Haynes also responded to witness Wielgus' claims regarding the benefits provided by Nucor to the Company's system, stating that the service arrangement with Nucor only requires a partial curtailment of its furnace load but not its total load and the Company is restricted in the number of hours such load can be curtailed. He noted that while Nucor's load factor may be considered higher than load factors for residential and small general service classes, it is not in the range of higher load factor customers in the LGS class. Witness Haynes also performed analyses of the value of Nucor's avoided capacity to the Company, concluding that while there was considerable value of curtailment to be considered in setting rates, the value was not as high as calculated by witness Wielgus. Witness Haynes also analyzed the benefit to the North Carolina jurisdiction and Nucor of recognizing Nucor's actually-curtailed peak load under the SWPA method. He concluded that recognizing Nucor's curtailed demand in developing the allocation methodology provides a significant and properly recognized financial benefit to Nucor, as well as a lower overall allocation of system costs to the North Carolina jurisdiction. He explained that the Company's SWPA allocation factors were calculated in a reasonable manner – consistent with the principles approved in DENC's 2016 Rate Case – that appropriately recognizes the value of Nucor's interruptibility to the system and does not overstate cost or understate returns for the North Carolina jurisdiction and its customer classes. *Id.*

In the Public Staff Stipulation, the Stipulating Parties agreed that the Company's SWPA methodology calculated using the system load factor to weight the average component and (1 – system load factor) to weight the peak demand component is appropriate for use in allocating the Company's per books cost of service to the North Carolina jurisdiction and between the customer classes in this case. The Public Staff Stipulation also agreed to the two adjustments made in the course of calculating the SWPA as described above.

The CIGFUR Stipulation states that, for purposes of settlement only, the parties agreed that the Company's SWPA methodology, calculated using the system load factor to weight the average component and (1 – system load factor) to weight the peak demand component is appropriate for use in allocating the Company's per books cost of service to the North Carolina jurisdiction and between customer classes in this case. The CIGFUR Stipulation also provides that the parties agree to the two adjustments the Company made in the course of calculating the SWPA. The parties did not reach a compromise on the total base revenue increases the Company proposed to assign to the LGS and 6VP customer classes or the Company's proposed rates of return for the customer classes. The parties agreed that in the next general rate case, the Company would file the results of a class cost of service study with production and transmission costs allocated on the basis of the Summer/Winter Coincident Peak method in addition to the SWPA used in this proceeding and consider such results for the sole purpose of apportionment of the change in revenue to the customer classes. They also agreed that considering that no customers have taken service under the pilot RTP rates filed by the Company and approved by the Commission in Sub 532, the Company will work with CIGFUR to consider whether certain provisions within those rates should be modified. If there is mutual agreement between CIGFUR and DENC to such modifications, and CIGFUR indicates that at least one of its member customers is willing to take service under such rates, DENC agrees to re-file such rates with the Commission for approval with the modifications agreed upon within 60 days of such agreement.

At the hearing, on redirect examination witness Haynes testified that under the alternative cost allocation methodologies proposed by Nucor and CIGFUR, Nucor would receive a rate decrease, and the residential class would receive rate increases ranging from approximately $20 million to $63 million, as compared to the $17 million increase provided in the Company's supplemental filing. Tr. vol. 5, 48-50.

Discussion and Conclusions

The Commission finds and concludes that DENC has carried its burden of proof to show that the Company's SWPA methodology is the most appropriate cost of service methodology to use in this proceeding to assign cost responsibility for production plant to the North Carolina jurisdiction and the Company's customer classes. On this issue, the Commission gives substantial weight to the testimony of Company witnesses Haynes and Miller and Public Staff witness Floyd, and both Stipulations. The cost of service methodology employed in establishing an electric utility's general rates should be the one that best determines the cost causation responsibility of the jurisdiction and various customer classes within the jurisdiction based on the unique characteristics of each class' peak demands and overall energy consumption. Witness Haynes testified extensively that the Company's investments in generating plant, including the recently placed in service Greensville CC, are designed to meet the Company's system peaks and to deliver low cost energy throughout the year. Witness Haynes explained that the SWPA methodology appropriately recognizes that DENC's system planning is designed to meet both the Company's peak and average system demands and energy needs of customers throughout the year. Both Company witnesses Haynes and Miller and Public Staff witness Floyd testified that the SWPA method appropriately matches allocation of production plant with DENC's generation planning and operations. The Commission finds that, for purposes of this proceeding, the SWPA cost of service methodology properly recognizes the manner in which DENC plans and operates its generating plants to provide utility service to customers in North Carolina.

Based on the facts in this case, a methodology that does not properly consider the effect of overall energy consumption, but focuses mainly on peak responsibility, such as the 1-CP methodology, would not properly represent the way in which the Company plans for and provides its utility service and the way customers use that service. The Commission is not persuaded that either the S/W CP methodology or the 1-CP methodology is appropriate for the Company in this proceeding, nor does the Commission see the need to open a formal proceeding to investigate the implementation of a 1-CP or 5-CP methodology for DENC in future rate cases. The disparity between allocation factors for peak demand-related factors and energy-related factors is apparent for each methodology, with the SWPA resulting in the most equitable sharing of the rate of return among DENC's customer classes in this case. Because the Commission finds that the SWPA method is not unreasonable or flawed, the Commission does not find Nucor witness Wielgus' arguments as to the inappropriateness of the SWPA methodology proposed by the Company in this proceeding persuasive. The Commission also continues to find and conclude that cost allocation does not lend itself to a one size fits all approach, and the specific circumstances of each utility must be considered when determining the appropriate cost allocation methodology for that utility.

Based on the stipulations and the testimony, the Commission also finds that including the distribution-interconnected NUG generation in the average portion of the SWPA, but not including this NUG generation in the Company's recorded summer and winter peaks creates a mismatch between the peak and average components of the Company's SWPA COSS. The Commission concludes that the Company's adjustment to the summer and winter peaks to recognize the NUG generation at the distribution level appropriately recognizes the impact those NUGs have on DENC's utility system and is approved.

Based on the stipulations and the testimony, the Commission also finds that the adjustment to remove demand and energy requirements of three customers for whom the obligation to provide generation service has ended or will end in 2019 is appropriate.

Based on the evidence in this proceeding, including the stipulations, the Commission finds and concludes that the greater weight of the evidence shows that the SWPA cost of service methodology provides the most appropriate methodology to assign fixed production costs by incorporating DENC's seasonal peak demands at the two single hours they occur and by incorporating the total energy consumed by the jurisdiction and customer classes over all the other hours of the year. In addition, the Commission finds good cause to require that the Company should continue to file a cost of service study using the SWPA methodology annually with the Commission.

Moreover, as a result of the opposing testimony between the DENC and CIGFUR witnesses, the Commission finds and concludes that the CIGFUR Stipulation is the product of the give-and-take between the parties during their settlement negotiations in an effort to appropriately balance DENC's usage of the SWPA and CIGFUR's desire to investigate a different methodology for the sole purpose of apportionment of the change in revenue to the customer classes in the next general rate case. The Commission finds and concludes that the CIGFUR Stipulation was entered into by the parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket. As a result, the CIGFUR Stipulation is material evidence to be given appropriate weight in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 40

The evidence supporting this finding of fact and conclusions is found in the verified Application, the testimony of Company witness Haynes, Public Staff witness Floyd, CIGFUR witness Phillips, Nucor witness Wielgus, the Public Staff Stipulation, and the entire record in this proceeding.

Summary of the Evidence

The Application and testimony and exhibits of Company witness Haynes explain how DENC proposed to apportion the jurisdictional revenue requirement established using the Company's SWPA jurisdictional and class COSS among the customer classes. Witness Haynes' testimony and exhibits assigned the revenue requirement to specific rate schedules and then calculated the percent increase that customers on each rate schedule would experience.

In apportioning the revenue requirement among the customer classes, witness Haynes identified general and class-specific principles that the Company used to equitably distribute the base rate revenue increase, including: (1) all classes should share in the non-fuel base rate revenue increase in a manner that moves each class of customers closer to parity with the North Carolina jurisdictional ROR; (2) generally, if a customer class has a ROR index less than 1.00, such class should receive a percentage increase that is greater than the overall jurisdiction percentage base rate increase. If a customer class has a ROR index greater than 1.00, such class should receive a percentage increase that is less than or equal to the overall jurisdiction percentage base rate increase; (3) for classes outside of a reasonable return index range of 0.90 and 1.10 (Parity Index Range), an effort must be made to more reasonably align the rates customers pay with their responsibility for cost, even if the index achieved after apportionment still remains outside of the Parity Index Range; (4) for purposes of apportioning the increase for the LGS, 6VP, and NS classes, which include the Company's large non-residential customers, in addition to the class rates of return and resulting indices, consideration should also be given to the appropriate increase for these customer classes based upon certain non-cost factors that support a lesser increase for large industrial customers with high load factors; and (5) for purposes of apportioning the increase to the NS Class, the Company recognized the need to equitably address the unique nature of the Company's electric service arrangement with its largest and most energy-intensive customer, Nucor. Tr. vol. 4, 384-87.

Specific to the non-cost considerations that DENC took into account in apportioning the revenue increase among the industrial customer classes, witness Haynes testified that he considered the quantity and timing of large industrial manufacturing customers' electric usage in their industrial operations, as well as factory utilization and the economic vitality of the Company's North Carolina service territory, as it relates to these industrial customers. Witness Haynes presented a summary table of the Company's allocated rate base, class rate of returns, apportionment of the non-fuel base rate increase, and the class rates of return after apportionment. Witness Haynes further detailed the proposed apportionment by class and explained that while the Company's customers would experience an increase in non-fuel base rates, this increase would be substantially moderated after taking into account certain reductions, like that anticipated for the fuel component of rates. *Id.* at 378-95.

After explaining how the proposed non-fuel base revenue increase was apportioned across customer classes, witness Haynes discussed how the components of the rate schedules are adjusted to achieve the non-fuel base rate increases. Witness Haynes stated that the target percentage increase listed by class in his summary table is applied to the total present revenue to calculate the target revenue increase for the rate schedule. Further, witness Haynes explained, a factor is used to adjust each rate component and applied to the present rates to develop a proposed rate that would result in the proposed revenue requirement. Witness Haynes noted that this information is included in Columns (7) through (14) of the Company's Form E-1 Item 42a summary sheet. Finally, witness Haynes noted that the rate design method used in this proceeding generally produced a proposed customer charge less than the fully-supported customer charges presented by witness Miller. *Id.* at 395-97.

In his testimony, Public Staff witness Floyd disagreed with the Company using only the base non-fuel revenue to calculate class rate of returns and instead recommended that DENC use both base fuel and base non-fuel revenues to determine base revenue assignment. Witness Floyd testified that, consistent with past rate cases, several principles should be taken into account when apportioning any combined base fuel and base non-fuel revenues among the various classes, all of which attempt to assign the revenue requirement to each customer class in an equitable and fair manner and to minimize rate shock to any individual class. Finally, witness Floyd explained that because the Public Staff recommended a total revenue decrease, all of the traditional principles the Public Staff rely on in apportioning the revenue requirement are not necessarily applicable. Witness Floyd testified that it is still appropriate to focus on addressing any disparities in the class rate of returns when apportioning the decrease, but any individual customer class revenue decrease should be limited so that no individual customer class sees an increase in its assigned revenue requirement. Tr. vol. 6, 72-77.

In his testimony, Nucor witness Wielgus disagreed with witness Haynes' rate design as it relates to Nucor and the proposed 0.80 rate of return index for the Schedule NS class. Witness Wielgus recommended that the percentage increase in base rates to Schedule NS should not exceed the average of the percentage increases applied to rate schedules in the LGS and 6VP classes. *Id.* at 393-96.

In his testimony, CIGFUR witness Phillips noted that the Company's proposed distribution of the revenue increase moves the rate of return for the 6VP and the LGS classes closer to cost and the system average rate of return. Witness Phillips recommended that because the Company's proposed method of distributing the requested increase to classes moves rates closer to cost in a meaningful manner, it should be implemented as proposed. *Id.* at 417-22.

In his rebuttal testimony, witness Haynes noted that witness Phillips' comment that the 6VP class has been providing "excess returns" to DENC, and pointed out that the same is true for the LGS class and that both classes are important to the Company's North Carolina service territory, with rate of return indices well above the Parity Index Range at 1.33 for the LGS class and 1.22 for the 6VP class. Witness Haynes explained that the Company considered the nature of these customers' usage, as well as concerns about the economic competitiveness of industrial customers and the need to maintain the economic vitality of the Company's North Carolina service territory. He pointed out that in the 2016 Rate Case, the Company gained approval of Rate Schedule 6L to help large high load factor customers who may utilize their plant efficiently in multiple daily shifts. Tr. vol. 4, 481-83.

Witness Haynes also disagreed with witness Wielgus' recommendation that Schedule NS should not exceed the average of the percentage increase applied to rate schedules in the LGS and 6VP classes. He stated that the rate of return index for the LGS and 6VP classes is well above the Parity Index Range and, given other non-cost factors, these two large industrial classes should receive a very low percentage increase. Witness Haynes further noted that the Company modified its position on the apportionment of the revenue increase to Schedule NS and that the Company believes that the Schedule NS class should have a lower rate of return index. Specifically, witness Haynes stated that in the 2016 Rate Case, the Schedule NS class' rate of return index moved from 0.43 to 0.74, which represented a move of two-thirds of the way toward the low end (90% of jurisdictional rate of return) of the Parity Index Range, and he noted that prior to the 2016 Rate Case based upon the stipulation and the Commission's order and Finding of Fact No. 42, this class received a non-fuel base rate increase that moved its ROR index from 0.43 to 0.75. This moved the NS class two-thirds of the way toward the low end (90% of jurisdictional ROR) of the Parity Index Range. Prior to the 2016 Rate Case, a deficiency had existed for a number of years, as reported in the Company's past rate cases and annual jurisdictional cost of service studies filed with the Commission. Witness Haynes stated that he discussed the Company's service agreement with Nucor and provided some reasonable calculations of the value of this agreement in his Rebuttal Schedule 2. In Rebuttal Schedule 3, he provided an analysis showing how the North Carolina jurisdiction is benefitting from the Company and Nucor having this service arrangement. Further, witness Haynes noted that earlier in his direct testimony filed on March 29, 2019, he proposed moving the Schedule NS class to a ROR index of 0.80. In the Company's supplemental filing, Schedule NS had a ROR Index of 0.79. Now, considering this operational benefit to the system and the benefit in cost allocation to the North Carolina jurisdiction because of the partially interruptible nature of service to Nucor, witness Haynes stated that he believes it is appropriate to target an ROR index of 0.75 for the Schedule NS class. He stated that this is a very important large industrial customer, and he believes that this reduction in the recommended ROR index is reasonable. *Id.* at 479-84.

In his Stipulation testimony, witness Haynes testified that Section VI[1] of the Public Staff Stipulation presents a just and reasonable approach to establishing the Company's North Carolina jurisdictional cost of service and class cost of service for the allocation of production and transmission plant costs and related expenses based on the SWPA allocation methodology. *Id.* at 486-88.

[1] At the hearing, witness Haynes corrected this statement in his testimony, which had referenced Section V of the Public Staff Stipulation. Tr. vol. 4, at 362.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

As contemplated by Section III.D of the CIGFUR Stipulation, counsel for CIGFUR cross-examined Company witness Haynes on the rate of return index provided for the LGS and 6VP classes under the Public Staff Stipulation. Witness Haynes agreed that these classes will be paying rates above cost and beyond the range of reasonableness but agreed with CIGFUR counsel that the increases for these classes are very small. He also pointed out that the terms of the Public Staff Stipulation result in a reduction in the increase in base non-fuel revenue from these classes from the Company's initial request. Tr. vol. 5, 40-43.

The Nucor Steel-Hertford brief states that through the testimony filed in this case, the Commission has been presented with reasoning justifying an ROR index for the NS class at either 0.70 or 0.75 only.[1] According to the Nucor brief, there is no reasoning on record (other than that contained in DENC's direct testimony which is superseded by DENC's Haynes rebuttal testimony advocating for 0.75) that supports an ROR index for Schedule NS/Nucor any higher than 0.75. Further, the brief states that simply put, there is no substantial record evidence supporting an ROR index of 0.80 for Schedule NS/Nucor.

Discussion and Conclusions

Based on the Public Staff Stipulation and the evidence in the record, the Commission concludes that for purposes of this proceeding it is appropriate to apportion the proposed base fuel and non-fuel revenue increase approved in this Order using the methodology recommended by DENC as consistent with the Public Staff Stipulation. In reaching this conclusion, the Commission gives substantial weight to the Public Staff Stipulation and the full record of testimony supporting the Stipulation. In support of the Stipulation, witness Haynes states that while other Company witnesses support the reasonableness of the stipulated non-fuel base revenue increase, he believes the Stipulation in Section V Cost Allocation, Rate Design, and Terms and Conditions, Paragraph A presents a just and reasonable approach to establishing the Company's North Carolina jurisdictional cost of service and class cost of service. He explained that this approach includes the allocation of production and transmission plant costs and related expenses based upon the SWPA allocation methodology calculated using the system load factor to weight the average component and (1 – system load factor) to weight the peak demand component. Tr. vol. 4, 486-87.

Further, witness Haynes stated that the Public Staff Stipulation addresses the apportionment of the revenue requirement and the design of rates in Section V, Paragraph B. With regard to these matters, the Stipulation provides the following according to witness Haynes:

1. To the extent possible, the Company shall assign the approved revenue requirement consistent with the principles regarding revenue apportionment described in the testimony of Public Staff witness Floyd.

2. The Stipulating Parties agree that the Company shall implement the rate design proposed by Company witness Haynes within his direct testimony, filed

[1] *See, e.g.*, Direct Testimony of Paul J. Wielgus at 17-19; Rebuttal Testimony of Paul B. Haynes at 45, lines 5-13, and 50, lines 2-10.

contemporaneously with the Company's Application in this docket as adjusted by this Stipulation.

3. The Stipulating Parties agree that all classes should share in the base case revenue increase.

4. In meeting the provisions of 1, 2, and 3 in apportioning the approved revenue requirement to the customer classes, awareness and consideration is given to the rate of return indexes for the LGS and 6VP classes being above 1.20 and an appropriate rate of return index for the Schedule NS class.

Witness Haynes stated that he considers these provisions of Section V, Paragraph B to be reasonable for the purpose of establishing rates in this proceeding. *Id.* at 487-88.

Finally, based on the entire record in this proceeding, the Commission is persuaded that the Company has treated the NS Class and Nucor appropriately in its cost of service study and that no additional recognition of the benefits associated with the Nucor contract should be made in this proceeding. The facts and evidence in this proceeding show that the Company has consistently followed the same approach in this case of recognizing the benefits of Nucor's interruptibility – to both Nucor and the North Carolina jurisdiction – consistent with DENC's approach in the Company's past three rate case proceedings. Further, the curtailment provisions in the Nucor agreement have not been modified since last reviewed by the Commission in 2016. Nucor's contract with the Company provides Nucor with flexibility in deciding how and when it consumes energy for the vast majority of hours in the year and the Company's treatment of Nucor through its SWPA methodology is reasonable and appropriate.

Based on the evidence presented, the Commission concludes that the rate of return indices for all of the classes are reasonable and should be accepted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 41-43

The evidence supporting these findings of fact and conclusions is found in the Company's Form E-1, the direct testimony of Company witnesses Haynes and Mitchell, the testimony of Public Staff witness Tommy Williamson, the Public Staff Stipulation, and the entire record in this proceeding.

Summary of the Evidence

Changes to service regulations

In his direct testimony, Company witness Haynes testified that Item 39 of the Company's Form E-1 shows the Company's proposed changes to each section of the terms and conditions of service, also known as the Company's service regulations. Specifically, he referenced the proposed changes to several miscellaneous service fees to cover the updated cost of service, excess facilities charge percentages, and minor wording changes. Witness Haynes stated that each change is accompanied by comments that provide a description of the relevant proposed change. He also testified that the Company proposed to wait to implement these changes until permanent rates become effective and the changes are approved by the Commission. Finally, witness Haynes confirmed that the non-fuel base rate revenue increase includes the Company's proposed changes to the miscellaneous charges. Tr. vol. 6, 383, 408-09.

No other party testified in opposition to the Company's proposed changes to the terms and conditions, and witness Haynes was not cross examined on this issue at the hearing.

Vegetation management

Public Staff witness Tommy Williamson described DENC's Vegetation Management Plan (VMP). He stated that there have been no significant changes in the VMP since April 2014, when it was filed by DENC in Docket No. E-22, Sub 491. Witness Williamson testified that DENC has approximately 4,160 miles of distribution right-of-way (ROW) that it maintains in North Carolina, and that the Company targets to trim approximately 800 miles annually. He further testified that the Company trims approximately 1,200 to 1,300 miles of transmission ROW annually, with about 200-300 miles of that work done in North Carolina. Finally, witness Williamson stated that DENC's VMP is reasonable in ensuring that all planned miles of trimming are done within the appropriate cycle.

Quality of service

Company witness Mitchell provided testimony regarding DENC's performance with regard to customer service. He testified that the Company's generating fleet has demonstrated excellent performance results. He also stated that DENC continues to provide excellent customer service, and that the Company has improved its North Carolina System Average Interruption Duration Index (SAIDI) performance, excluding major storms, by over 20% since 2007, and maintained consistent performance below 120 minutes since 2016. Witness Mitchell also testified that the Company continues to achieve excellence in customer service by offering innovative solutions in response to customer expectations, including leveraging technology to perform quick, seamless customer transactions. He noted that DENC customers completed more than 16 million online transactions during 2018 and that usage of online transactions has increased by 12% since 2017. He described the Company's promotion of social media interactions with customers, including its messages to educate customers on important issues such as energy conservation and service reliability. Witness Mitchell also testified about recognition for outstanding performance that the Company's parent, DEI, had received during the past several years. Tr. vol. 6, 169-70, 178-81.

Public Staff witness Tommy Williamson testified that the Public Staff had reviewed service-related complaints received by the Public Staff's Consumer Services Division, the Company's call center operation reports filed with the Commission, SAIDI performance, and System Average Interruption Frequency Index (SAIFI) statistics. Witness Williamson testified that the data for non-Major Event Days showed that the Company's SAIDI and SAIFI results have been stable and slightly improving. He also testified that the vast majority of inquiries made by DENC customers through the Public Staff's Consumer Services Division were requests to establish or modify payment arrangements, and that no other category of inquiry exceeded 4% of the total. Based on this information, witness Williamson found the overall quality of electric service provided by DENC to retail customers to be adequate. Tr. vol. 6, 466-67.

In Section IX of the Public Staff Stipulation, the Stipulating Parties agreed that the quality of DENC's service is good.

Conclusions

The Commission finds and concludes that the Company's proposed changes to its service regulations, as included in Item 39 of its Form E-1, are reasonable and appropriate, and should be approved.

In addition, the Commission finds and concludes that DENC's VMP performance is reasonable and should be accepted.

Further, the Commission finds and concludes that DENC's overall quality of service is good.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 44–46

The evidence supporting these findings of fact and conclusions is found in the testimony of Company witness Williams, the Company's 2015 Integrated Resource Plan, the testimony of Public Staff witness Lucas, and the Public Staff Stipulation.

Summary of Evidence

In his direct testimony Company witness Williams discussed DENC's strategy for complying with federal and state environmental regulations. Witness Williams testified that to comply with the CCR Rule[1] and the Environmental Protection Agency's (EPA's) effluent limitations guidelines (ELGs),[2] the Chesterfield Power Station (Chesterfield) underwent a number of wastewater and environmental improvements in 2017 to transition from wet sluicing coal ash to a dry ash management system. In order to manage the dry coal ash, DENC constructed an onsite, permitted landfill. Witness Williams stated that the onsite landfill has been receiving dry ash since 2017. Overall, witness Williams testified that the Company's actions to close its ash facilities have been reasonable and prudent. Tr. vol. 5, 90, 93.

Public Staff witness Lucas testified that in 2015 the Company began making investments at Chesterfield to comply with the CCR Rule and the ELGs. These investments are referred to by the Company as the Chesterfield Integrated Ash (CHIA) project. He explained that the CHIA project included wet to dry conversion of several units, among other things. Witness Lucas testified that in June 2015 the Company executed an agreement with a contractor to design and build dry

[1] Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities, 80 Fed. Reg. 21,301 (Apr. 17, 2015).

[2] Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 80 Fed. Reg. 67,837 (Nov. 3, 2015).

ash handling facilities for Chesterfield Units 3, 4, 5, and 6, and that the total CHIA project cost was $124.2 million. Witness Lucas further testified that in its 2015 Integrated Resource Plan (IRP) the Company indicated that Units 3 and 4 would be retired in 2020. Witness Lucas testified that Chesterfield Units 3 and 4 were retired in March 2018. Witness Lucas testified that the Company should not have made this long-term investment in Units 3 and 4 if they were to remain in service for less than five years. As a result, he opined that the investment made to convert these two units to dry ash handling was not prudent, and he recommended a disallowance of $25.7 million on a system-wide basis.

Witness Lucas calculated the disallowance based on the total generating capacity of Chesterfield Units 3, 4, 5 and 6, 1,302 MW, in relation to the combined capacity of Units 3 and 4, which is 270 MW, or 20.7% of the total Chesterfield Units 3, 4, 5 and 6 capacity. Witness Lucas applied the 20.7% capacity ratio to the $124.2 million total cost of the CHIA project to arrive at the recommended disallowance of $25.7 million on a system-wide basis. Tr. vol. 6, 189-91.

Witness Lucas also discussed the proceeding in which the Virginia State Corporation Commission (VSCC) addressed this issue.[1] In its Final Order issued on August 5, 2019, the VSCC concluded that the costs incurred by VEPCO for the CCR wet to dry conversions of Units 3 and 4 was not reasonable and prudent, and, therefore, the VSCC denied recovery of those costs. Final Order, at 6-9. However, on August 23, 2019, VEPCO filed a Limited Petition for Reconsideration, requesting that the VSCC review its denial of the conversion costs for Units 3 and 4. On August 26, 2019, the VSCC issued an Order Granting Reconsideration that accepted VEPCO's petition and suspended operation of the Final Order pending further action by the VSCC on the petition.

Finally, witness Lucas disagreed with DENC witness Williams' contention that the EPA's 2015 ELGs forced DENC to convert its coal plants to dry ash handling. Witness Lucas testified that in September 2017 the EPA postponed the earliest compliance date for the new effluent limitations and pretreatment standards for FGD wastewater and bottom ash transport water for two years, from November 1, 2018, to November 1, 2020.

In her testimony, Public Staff witness Johnson made an adjustment to remove the costs associated with the common plant related to Chesterfield Units 3 and 4 based on the recommendation of witness Lucas, resulting in an annual revenue requirement reduction of $124,000. Tr. vol. 6, 33; Johnson Exhibit 1, Schedule 1(a).

The Public Staff Stipulation, in Section VII.A, provides that the costs of the wet to dry conversion for Units 3 and 4 at Chesterfield should be included in the stipulated revenue requirement, pending resolution of the dispute in Virginia. Section VII.A further states that if the final resolution in Virginia results in such costs being removed from the Virginia Rider E revenue requirement, the Company will establish a regulatory liability for estimated amounts recovered from North Carolina customers associated with the project costs beginning November 1, 2019, and

[1] Final Order, *Petition of Virginia Electric and Power Company for Approval of a Rate Adjustment Clause, Designated Rider E, for the Recovery of Costs Incurred to Comply with State and Federal Environmental Regulations Pursuant to § 56-585.1 A 5 E of the Code of Virginia*, No. PUR-2018-00195 (Va. S.C.C. Aug. 5, 2019), *reh'g granted*, (Va. S.C.C. Aug. 26, 2019).

ending on the effective date of rates established in the Company's next general rate case, and that the amortization of the regulatory liability balance will be incorporated into the revenue requirement developed in the Company's next general rate case.

Discussion and Conclusions

The Commission concludes that the result proposed in Section VII.A of the Public Staff Stipulation is not acceptable. The Commission has the utmost respect for the VSCC and is confident that the VSCC will reach a reasoned decision on the Chesterfield Units 3 and 4 conversion costs. However, under the Act the Commission has the authority and obligation to set just and reasonable rates for DENC in North Carolina. The Commission concludes that it should not delegate any portion of its authority and obligation to the VSCC, which would be the direct result of approving Section VII.A of the Public Staff Stipulation. Consequently, the Commission declines to accept Section VII.A of the Public Staff Stipulation, and proceeds with making its own independent analysis of the prudence and reasonableness of the Chesterfield Units 3 and 4 CCR conversion costs.

Pursuant to N.C.G.S. § 62-134(c), the utility has the burden of proof to show that its proposed rates are just and reasonable. Further, N.C.G.S. § 62-65(a) requires that the Commission's orders be based on competent, material and substantial evidence.

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* 1054 (Houghton Mifflin Co., 1978).

With respect to prudence and reasonableness, the Commission applies the following general standard:

> [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. . . . 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.

Order Granting Partial Increase in Rates and Charges, *Application by Carolina Power & Light Company for Authority to Adjust and Increase Its Rates and Charges*, No. E-2, Sub 537, at 14 (N.C.U.C. Aug. 5, 1988), *rev'd in part on other grounds and remanded, Utils. Comm'n v. Thornburg*, 325 N.C. 484, 385 S.E.2d 463 (1989) (Harris Order).

With regard to DENC's decisions on the Chesterfield wet to dry conversion project, the Commission finds that there are four dates that inform the analysis of "whether management decisions were made in a reasonable manner and at an appropriate time." The first date is 2009. In a 2009 study by Golder Associates entitled "Chesterfield Dry Ash System Installation," Golder advised VEPCO on design and cost analyses performed by Golder for a wet to dry ash handling system conversion at the Chesterfield plant. In a letter to VEPCO dated June 10, 2009, Golder stated:

> [D]ue to a recent catastrophic spill event in Tennessee and the changing political climate with regard to open ash ponds, Dominion has chosen to evaluate alternatives to the waste handling system at the Station should the lower ash pond be closed and no longer available to receive the ash slurry. Golder was asked to analyze possible ash conveyance system alternatives for transporting an estimated 550,000 tons of ash per year to the proposed Facility and to develop a budgetary cost estimate for the conversion.
>
> . . .
>
> Based on a review of available Station information, two site visits and discussions with Dominion, Golder believes a conventional wet-dry ash conversion is practical for the Station.

DENC Late-Filed Exhibit 4 (Part 1) at 148 (filed September 23, 2019).

The 2009 Golder study and recommendation is material evidence because of the eventual timing of the 2015 decision to proceed with wet to dry conversion at Chesterfield, and the 2018 retirement of Units 3 and 4. Had DENC gone forward with the wet to dry conversion in 2009, as recommended by its consultant, then it would have benefited from several more years of using the dry handling system at Units 3 and 4, rather than using the system for less than two years.

The second important date is 2015, for two reasons. First, as Public Staff witness Lucas testified, in June 2015 the Company executed an agreement with a contractor to design and build dry ash handling facilities for Chesterfield Units 3, 4, 5, and 6. Second, on July 1, 2015, DENC filed its 2015 IRP in Docket No. E-100, Sub 141. In Section 3.1.4, under the sub-heading "Retirements," DENC stated:

> [A]lso under evaluation are the retirements of Chesterfield Units 3 (98 MW) and 4 (163 MW), and Mecklenburg Units 1 (69 MW) and 2 (69 MW), all modeled for retirement in 2020 (Plans A, C and D). Appendix 3J lists the planned retirements included in the 2015 Plan.

DENC's 2015 IRP at 35.

The third important date in the Commission's analysis is 2017. DENC witness Williams testified that the CHIA project was completed in 2017, and the onsite landfill began receiving dry ash.

The fourth important date is 2018, the year that DENC retired Chesterfield Units 3 and 4.

The Commission concludes that the above dates and events are substantial evidence bearing on the question of what DENC knew, or should have known, when it made the decision to expend millions of dollars on a dry ash handling system for Chesterfield Units 3 and 4. In weighing this evidence, the Commission gives substantial weight to the fact that virtually simultaneously in June and July 2015 DENC signed a contract that included the conversion of Chesterfield Units 3 and 4 to dry ash handling while planning to retire Chesterfield Units 3 and 4 in 2020.

Further, the Commission gives substantial weight to DENC's 2015 IRP. The IRPs are planning documents in which the electric utilities invest many hours of expert thought and time. They are also documents on which the electric utilities and the Commission depend heavily in meeting their obligations to ensure reliable service. The Commission concludes that DENC having stated in its 2015 IRP that it planned to retire Chesterfield Units 3 and 4 in 2020, and having modeled its IRP on the basis of that planned retirement of Chesterfield Units 3 and 4 in 2020, DENC knew with reasonable certainty that it would retire Chesterfield Units 3 and 4 in 2020.

The Commission also gives substantial weight to the fact that the CHIA project was completed in 2017. The Commission notes that contracts for such major construction projects typically include a projected completion date, and although not necessarily absolute, the target date is generally relied upon by the contracting parties. Thus, it is a reasonable inference that DENC knew in 2015, or had a reasonable expectation, that the CHIA project would be completed sometime in 2017, and, therefore, Chesterfield Units 3 and 4 would use the dry ash handling equipment for only three years prior to their planned retirement in 2020.

Based on the substantial, material and competent evidence presented by DENC and the Public Staff, the Commission finds and concludes that DENC's decision to include Chesterfield Units 3 and 4 in the CHIA project was not reasonable and prudent. In 2015, when DENC entered into the contract for conversion from wet to dry handling, DENC knew with reasonable certainty that it would retire Chesterfield Units 3 and 4 in 2020. With that knowledge, it was not reasonable or prudent for DENC to spend millions of dollars on a wet to dry conversion for CCR handling at Chesterfield Units 3 and 4 in 2017. As a result, DENC's cost of converting Chesterfield Units 3 and 4 to dry ash handling should not be recovered from DENC's retail ratepayers.

The Commission accepts Public Staff witness Lucas's calculation of the disallowance of $25.7 million on a system-wide basis, and Public Staff witness Johnson's North Carolina retail adjustment resulting in an annual revenue requirement reduction of $124,000. Johnson Exhibit 1, Schedule 1(a). Further, the Commission finds good cause to require DENC to consult with the Public Staff and provide the Commission with confirmation that the Public Staff's recommended adjustment will result in the removal of all North Carolina retail jurisdictional costs and effects arising from the wet to dry CCR conversion project for Units 3 and 4 of the Chesterfield Power Station from DENC's revenue requirement and rate base.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 47-48

The evidence supporting these findings of fact and conclusions is found in the testimony and exhibits of the Company and the Public Staff, the testimony of CIGFUR witness Phillips, and in the Public Staff and CIGFUR Stipulations.

Pursuant to N.C.G.S. § 62-133(a), the Commission is required to set rates that are "fair both to the public utilities and to the consumer." In order to strike this balance between the utility and its customers, the Commission must consider, among other factors: (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. *See* N.C.G.S. § 62-133(b).

As fully discussed above, the provisions of the stipulations are the product of the give-and-take of settlement negotiations between DENC and the Public Staff, and between DENC and CIGFUR. In comparing the Public Staff Stipulation to the Company's Application and considering the direct testimony of the Public Staff's witnesses, the Commission notes that the Public Staff Stipulation results in numerous downward adjustments to the costs sought to be recovered by DENC. In addition, it is readily apparent from the terms of the Public Staff and CIGFUR Stipulations that the Stipulating Parties weighed their interests and negotiated to achieve the results most important to them, while also being willing to recognize the priorities of the other side in order to reach compromise. The result is that the stipulations strike a fair balance between the interests of DENC and its customers.

As discussed above, the Commission has fully evaluated the provisions of the stipulations and concludes, in the exercise of its independent judgment, that the provisions of the stipulations are just and reasonable to all parties to this proceeding in light of the evidence presented, and serve the public interest, with the exception of Section VII.A of the Public Staff Stipulation and subject to the qualifications and direction provided in Findings of Fact Nos. 60-62 and the discussion thereunder relating to the costs of removal portion of depreciation allowance. In particular, the provisions of the Stipulations appropriately balance the interests of DENC's customers in receiving safe, adequate, and reliable electric service at the lowest possible rates, and the interests of DENC in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the stipulations are just and reasonable under the requirements of the Act. Therefore, the Commission approves the Stipulations in their entirety, with the exception of Section VII.A of the Public Staff Stipulation and subject to the qualifications and direction provided in Findings of Fact Nos. 56-58 and the discussion thereunder relating to the costs of removal portion of depreciation allowance.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 49-52

The evidence supporting these findings and conclusions is contained in the Public Staff Stipulation, the Company's verified Application and Form E-1, DENC's Late-Filed Exhibits 3, 4, 5 and 6 filed on September 23, 2019, and the testimony and exhibits of the following expert witnesses: DENC witnesses Williams, McLeod, and Mitchell; and Public Staff witnesses Lucas and Maness.

The testimony and exhibits regarding DENC's CCR costs are voluminous. The Commission has carefully considered all of the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witness. Rather, the following is a summary of the evidence that is in the record. Likewise, while the Commission has read and fully considered the parties' post-hearing briefs, it has not in this order attempted expressly to discuss every contention advanced or authority cited in the briefs.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

Summary of the Evidence

Direct Testimony of Witnesses Mitchell and McLeod (DENC)

In his direct testimony Company witness Mitchell testified that DENC is requesting recovery of CCR compliance expenses incurred from July 1, 2016, through June 30, 2019. Tr. vol. 4, 176. The costs for that period are estimated to be $390.4 million. *Id.*

Company witness McLeod explained that the Company's proposed revenue requirement in this proceeding includes a recovery of expenditures made during the period of July 1, 2016, through June 30, 2019 in continued compliance with federal and state environmental regulations associated with managing CCRs and converting or closing waste ash management facilities at seven of DENC's generating stations. *Id.* at 27. As witness McLeod explained, pursuant to the 2016 DENC Rate Case Order the Company was permitted to recover CCR expenditures incurred through June 30, 2016, over a five-year amortization period and to defer subsequent costs to be evaluated for recovery in future rate cases.[1] In his supplemental testimony witness McLeod updated the amount of CCR costs sought for recovery during the period of July 1, 2016, through June 30, 2019, to reflect actual cash expenditures and the associated financing costs. *Id.* at 313. The Company is proposing to recover $377 million in system-level asset retirement obligation activities. Of this total the Company is seeking recovery of $21.8 million from the North Carolina retail jurisdiction.[2] Tr. vol. 6, p. 686. The Company originally proposed to recover these expenses over a three-year amortization period, tr. vol. 4, 27, but modified that proposal to a five-year amortization period, consistent with the Commission's treatment of similar deferred CCR costs in the recent DEP and DEC rate cases. Tr. vol. 6, 687. Witness McLeod explained that the unamortized CCR regulatory asset balance is included in the working capital section of rate base, which provides for recovery of financing costs associated with investor-supplied funds until they are recovered from customers. *Id.*

Direct Testimony of Witness Williams (DENC)

Witness Williams described the federal and state regulatory requirements that drove the CCR expenditures incurred from July 1, 2016, through June 30, 2019. Witness Williams explained that, as the Director, Environmental Services for Dominion Energy, it was his responsibility to oversee the corporate waste, water and biology programs. Tr. vol. 5, 77. He testified that his responsibilities included providing environmental support and leadership to the CCR closure projects. *Id.* at 94.

Witness Williams described his education and experience. He testified that he was a licensed Professional Geologist and earned a Bachelor of Science degree in geology from Radford University in 2001. Prior to joining Dominion Energy, witness Williams worked as an

[1] 2016 DENC Rate Case Order at 63, 149.

[2] The $21.8 million consists of the North Carolina jurisdictional portion of $376.7 million, $19.2 million, plus financing costs of $2.7 million that were incurred from the period of July 1, 2016, through June 30, 2019. *See* Maness Supplemental Exhibit 1, Schedule 1.

environmental manager at Waste Management Inc., North America's largest waste company, where he was responsible for environmental permitting and compliance for thirteen landfills located in Virginia, Maryland, Delaware, and West Virginia as well as over thirty trucking and transfer facilities located throughout the mid-Atlantic. Witness Williams was employed by the United States Navy, where he was responsible for the management and oversight of all east coast Marine Corps environmental remediation projects, including coal ash landfills, debris landfills, and many petroleum or chemical release sites. Witness Williams was also employed by the Virginia Department of Environmental Quality (VA DEQ), where he served as the solid waste permitting coordinator responsible for establishing the permitting standards for landfills, including ash and other industrial landfills. In his role with VA DEQ, witness Williams also led VA DEQ's revision of the Virginia coal combustion byproduct regulations, which governed the use of coal ash as structural fill before EPA's issuance of the CCR Rule. *Id.* at 94-95.

Witness Williams explained that DENC's CCR costs are attributable to eight Company generating facilities that are subject to new requirements for the closure of CCR surface impoundments, or ponds, and the continued operation of CCR landfills under federal and state regulations. Those facilities are: Bremo Power Station (Bremo), Chesapeake Power Station (Chesapeake), Chesterfield Power Station (Chesterfield), Clover Power Station (Clover), Mount Storm Power Station (Mt. Storm), Possum Point Power Station (Possum Point), Virginia City Hybrid Energy Center (Virginia City), and Yorktown Power Station (Yorktown). According to witness Williams, the coal ash stored at these facilities is the byproduct of decades of efficient and reliable energy generation for the Company's customers. Tr. vol. 5, 78-80.

Witness Williams testified that the Company is required to close its CCR ponds, and, eventually, when they cease receiving waste ash, its CCR landfills at these eight sites because of the CCR Rule that was published by the U. S. Environmental Protection Agency (EPA) on April 17, 2015. The CCR Rule finalized national regulations that provided a comprehensive set of requirements for the disposal of CCR from coal-fired power plants. The CCR Rule established technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act (RCRA). These regulations address location restrictions, operating and design criteria (including dam safety and stability), closure and post-closure care, and groundwater monitoring and corrective action requirements for CCR surface impoundments. The CCR Rule also sets out recordkeeping and public reporting requirements. *Id.* at 79.

Witness Williams testified that under the CCR Rule the Company had two options for closing its CCR surface impoundments: (1) closure in place, or (2) excavation and removal. For closure in place, the ash basin would be dewatered and then capped with an impervious cover. For closure by removal, the ash basin would be dewatered, then the ash would be excavated and placed in a lined, permitted CCR landfill. The CCR Rule also allowed excavated CCR to be beneficially reused under certain conditions. *Id.* at 80.

Witness Williams also described additional changes to federal regulations that impacted DENC's coal-fired facilities. On September 30, 2015, EPA finalized the Effluent Limitation Guidelines (ELG) rules revising the regulations for the Steam Electric Power Generating category. 40 C.F.R. Part 423. According to witness Williams, the rule set new federal limits on multiple metals found in wastewater that may be discharged from power stations including a prohibition on discharges associated with bottom ash management systems. Tr. vol. 5, 80.

Witness Williams testified that to meet the requirements of the CCR Rule the Company developed closure plans for each of its CCR ponds and landfills.[1] Witness Williams explained that the Company's original closure plans for its CCR surface impoundments, which were located at Bremo, Chesapeake, Chesterfield, and Possum Point, ultimately called for closure in place. The Company's original closure plans for those facilities remained effective until March 2019, when the Governor of Virginia signed into law Senate Bill 1355 (SB 1355). Senate Bill 1355 mandated that the Company excavate its CCR impoundments located in the Chesapeake Bay watershed, which include the ash basins at Bremo, Chesapeake, Chesterfield, and Possum Point. Excavated ash must be beneficially reused or placed in lined landfills located onsite or offsite. DENC will also be required to recycle or beneficiate approximately 25% of the excavated CCR, if it is determined through additional studies to be economically feasible. Witness Williams explained that Virginia's new excavation requirement is consistent with actions other states and utilities are taking in North Carolina, South Carolina, Georgia, and Alabama. *Id.* at 81-83.

Witness Williams clarified that SB 1355 has not affected the costs that are the subject of this proceeding, but when compared to closing all ponds in place the Virginia legislation requirements will result in an increase of the cost of closure. He further testified that the Virginia closure requirements allow multiple options for removal to onsite or offsite landfills as well as establishing a reasonable recycling target to limit that increase. He opined that closure in place comes with the uncertainty of future operations and maintenance, including corrective action for groundwater, and that the Virginia legislation removes this uncertainty by establishing excavation of basins and placement of the ash in a lined solid waste landfill as the only closure method. *Id.* at 93.

Witness Williams testified that DENC has historically managed CCR consistently with evolving industry standards and regulatory requirements. He stated that over time the utility industry and DENC have primarily used two types of disposal methods for managing CCR: surface impoundments for sluiced CCR and landfills for dry CCR. Witness Williams stated that as of 1988, 80% of CCR generated by the utility industry was stored in surface impoundments or landfills. He stated that DENC has also sought opportunities to find beneficial uses for CCR, including use as an ingredient in concrete and dry wall. Witness Williams stated that by 2012, 40% of the CCR being generated was beneficially reused while the remaining 60% was being stored in CCR impoundments and landfills. Since the 1990s, DENC has recycled an annual average of 500,000 tons of CCR for beneficial reuse in the concrete and drywall industries. *Id.* at 84-85.

Witness Williams provided an historical summary of CCR management at each of the Company's eight coal-fired facilities and further described the CCR Rule compliance activities that occurred from July 1, 2016, through June 30, 2019, for which DENC is seeking recovery in this case. He further testified that the Company's actions to comply with the federal and state requirements have been reasonable and prudent. Tr. vol. 5, 93. According to witness Williams, no

[1] As required by the CCR Rule, DENC published its closure plans on its public website: www.dominionenergy.com/ccr.

witness in this case has challenged or recommended disallowances related to the Company's strategy and activities described below to comply with the CCR Rule. *Id.* at 165. The following is a summary of the history of DENC's electric generating plants provided by witness Williams.

Bremo

Bremo was commissioned in 1931 as a coal-fired power station. CCR management consisted of sluicing wet fly and bottom ash to three onsite ash ponds — the East, West, and North ponds. The East Ash Pond (EAP) was constructed in multiple stages, beginning in the 1930s. *Id.* at 86. The EAP stopped receiving CCR in the mid-1980s and became inactive thereafter. *Id.* at 118-19. The West Ash Pond (WAP) was constructed in the late 1970s. The North Ash Pond (NAP) was constructed in two phases in 1982 and 1983. The NAP and WAP ponds continued to receive CCR until the Company converted the station to natural gas in 2014. *Id.* at 86. That process involved sluicing ash directly to the WAP; the ash was then hydraulically dredged to the NAP as needed to make room in the WAP. *Id.* at 120-21.

According to witness Williams the EAP and WAP at Bremo were considered "inactive" ash ponds under the CCR Rule. As such, DENC proceeded expeditiously to close the inactive ponds at Bremo by consolidating the EAP and WAP into the NAP, which was the largest pond and the pond located furthest from surface waterways. Since April 20, 2015, ash from the East and West Ponds was excavated and consolidated in the North Pond. The consolidation activities continued through March 2019. DENC could not proceed further with closing the NAP because of the permitting moratoriums created by SB 1398 and SB 807 that were passed by the Virginia General Assembly in 2017 and 2018, respectively. *Id.* at 90.

Chesapeake

Chesapeake was commissioned in 1953 as a coal-fired power station and continued to operate until December 31, 2014. All CCR from Chesapeake was originally managed in a single, onsite ash pond. *Id.* at 87. In the early 1970s, the generating units at the site were converted to burn oil. However, the Company returned to burning coal at Chesapeake in the 1980s. By this point, EPA had passed the Clean Air Act (CAA), which required substantial improvements to the air pollution control equipment for new coal-fired units. In order to comply with the CAA, the Company installed pneumatic fly ash management and constructed a landfill permitted by Virginia DEQ on top of the historic ash pond to handle the dry fly ash. *Id.* at 140. Bottom ash has been sluiced to a separate bottom ash pond. Both the landfill and bottom ash pond are located within the footprint of the original ash pond. The coal-fired generation units at Chesapeake ceased operations on December 31, 2014 and have been decommissioned. *Id.* at 87.

On November 13, 2018, DENC signed a Memorandum of Agreement (MOA) with the Commonwealth of Virginia pursuant to which the Company agreed to groundwater monitoring and closure steps for coal ash at Chesapeake consistent with the standards imposed by CCR Rule regulations. The bottom ash pond is the only portion of the Chesapeake ash complex subject to the CCR Rule. However, this pond was constructed on top of the historic ash pond without a liner system. The adjacent landfill (also constructed on top of the historic ash pond) is subject to a Virginia DEQ solid waste permit that requires groundwater monitoring of the entire ash complex.

Therefore, although the historical pond and landfill are not subject to the CCR Rule, there is no way to distinguish groundwater from the bottom ash pond from that which is in contact with the historic ash pond. As such, the MOA was agreed to in order to ensure that the closure and monitoring of the historic ash pond and adjacent landfill would be consistent with the CCR Rule. All three of the ash facilities (original ash pond, landfill, and bottom ash pond) are slated for closure once necessary permits are obtained. Only minor closure activities have occurred within the Chesapeake ash facility. Between October 16, 2017, and March 9, 2018, a small amount of ash was removed from the bottom ash pond for recycling. However, with the passage of SB 807 all further removal activities were halted until such time as a path forward was directed by the Virginia General Assembly. *Id.* at 90-91.

Chesterfield

Chesterfield was commissioned in 1944 as a coal-fired power station. Sluiced fly ash and bottom ash at Chesterfield was originally managed in the Lower Ash Pond (LAP) and Upper Ash Pond (UAP) where it was wet sluiced from the station. The LAP was constructed in two phases in 1964 and in 1967 to 1968. The UAP was constructed in 1985 to receive sluiced ash from the station and dredged ash from the LAP. The station ceased sluicing ash in 2017 when the plant converted to dry ash management. Flue gas desulfurization (FGD) solids have been generated at the site since 2008 as a byproduct from scrubbers used to clean air emissions. The FGD sludge is primarily composed of calcium sulfate or gypsum, which is beneficially reused as wallboard quality gypsum. *Id.* at 86-87.

The CCR Rule required that DENC close both the UAP and LAP at Chesterfield. The Company has continued to operate coal-fired units at Chesterfield as a coal-fired station. To comply with EPA's CCR and ELG Rules, Chesterfield underwent a number of wastewater and environmental improvements in 2017 to transition from wet sluicing coal ash to a dry ash management system. In order to manage the dry coal ash, DENC constructed an onsite, permitted landfill. The onsite landfill has received dry ash since 2017. The Company began the process of closing the LAP and UAP pursuant to federal and state requirements. *Id.* at 90.

Clover

Clover was commissioned in 1995 as a coal-fired power station. The station has operated a dry fly and bottom ash system since it began to generate power. CCR has been taken to an onsite landfill for disposal, which is divided into three areas, or stages. Two landfill stages reached their maximum storage capacity in April 2003 and were subsequently closed in compliance with Virginia DEQ regulations. Since 2003, dry fly ash and bottom ash has been stored in Stage III of the landfill. Clover also has two sedimentation basins used for settling wastewater solids, including FGD, prior to removal and disposal to the landfill. The water from these ponds is recirculated and FGD wastewater is not discharged. These ponds have been in place and operated since 1995. *Id.* at 88.

Under the CCR Rule, DENC will be required to close both FGD basins at Clover. CCR has been removed from the FGD basins, and those basins have been retrofitted with a CCR Rule compliant liner. DENC maintains compliance with its state permits and other CCR Rule requirements related to its CCR units at the site. The removal of the first sedimentation basin began in 2017, and its replacement meeting the requirements of the CCR Rule was placed into service in 2018. The second sedimentation basin was removed and construction was scheduled to be completed by June 2019. *Id.* at 92.

Mt. Storm

Mt. Storm is located in Bismarck, West Virginia, and is part of DENC's operating system. Mt. Storm was first commissioned in 1965 and continues to operate as a coal-fired power station. Dry fly ash and bottom ash are stored in the onsite lined Phase B landfill that is permitted by the West Virginia Department of Environmental Protection (West Virginia DEP). The FGD sludge from Mt. Storm is beneficially reused in mine reclamation projects to neutralize mine acid runoff and in the manufacturing of Portland cement. Excess FGD sludge is disposed of in the onsite lined Phase A landfill. *Id.* at 88.

Mt. Storm historically managed ash contact water from the ash loading area and bottom ash hydro-bins in five small low volume waste treatment ponds (Pyrite Pond and Ponds A, B, C, and D). These ponds did not meet the liner standards of the CCR Rule but were needed for continued operation of the station. Therefore, the five original ponds were closed by removal and the contents were placed in the onsite Phase B landfill. The station then constructed a new pyrite pond and two low-volume wastewater treatment ponds in the location of the former ponds. The onsite landfills (Phase A and B landfills) and their liners meet the CCR Rule's definition of an active landfill and, as such, have been allowed to continue to operate under the CCR Rule. The closure of these ponds and construction of new ponds meeting the requirements of the CCR Rule began in early 2016. The majority of the removal and construction was completed in 2018. Construction of the final pond's concrete liner was scheduled to be completed in Spring 2019. DENC continues to maintain compliance with its state permits and CCR Rule requirements related to its CCR units at the site. *Id.* at 92-93.

Possum Point

Possum Point was commissioned in 1948 as a coal-fired station. CCR management involved sluicing wet fly and wet bottom ash to five onsite ash ponds. These ponds were named Ash Ponds A, B, C, D, and E. Ponds A, B, and C are contiguous and were used as water treatment ponds to settle and manage low-volume wastewaters containing CCR from approximately 1955 to 1967. *Id.* at 85. The A, B, C ponds were in an inactive state and were partially covered in vegetation until compliance activities under the CCR Rule began in 2016. *Id.* at 103-04. When the ponds were closed in 1967, there were no applicable capping or closure standards. *Id.* at 104. The original Pond D was constructed in the early 1960s before Ponds A, B, and C reached capacity and received CCR until 1971. The Company completed construction on a new Pond E in 1968. In 1986, Pond E was nearing capacity, so the Company began construction on a new Pond D embankment to provide additional onsite storage space. The new Pond D was constructed with a 12" thick clay liner system. Ponds D and E continued to accept ash until the station's coal units were converted to natural gas in 2003. *Id.* at 85-86. After 2003, Pond E continued to receive low-volume wastewater streams from the plant, but not coal ash, until CCR Rule compliance activities began. *Id.* at 109.

The CCR Rule included provisions for "inactive" ash ponds that no longer received CCR after October 14, 2015. Ash ponds meeting the definition of "inactive" were required to close within three years or otherwise be subject to long-term monitoring and other costly provisions of the CCR Rule. DENC's ash ponds at Possum Point qualified as "inactive" under the CCR Rule. Accordingly, DENC proceeded expeditiously to close the inactive ponds at Possum Point by consolidating the contents of Ponds A, B, C, and E into Pond D, which is the largest pond at this site, is the furthest from waterways, and is also the only pond at Possum Point with a liner. In 2018, DENC completed the excavation of ash from Ponds A, B, C, and E. DENC could not proceed further with closing Pond D because of the permitting moratoriums created by SB 1398 and SB 807 that were passed by the Virginia General Assembly in 2017 and 2018, respectively. *Id.* at 89.

Virginia City

Virginia City was commissioned in 2012. All fly ash and bottom ash from the station is collected from the power station and moved by truck to the lined, onsite Curley Hollow CCR landfill. The landfill has a state-of-the-art design including a synthetic liner and leachate collection/treatment systems. *Id.* at 87.

Beginning in May 2016, DENC began installing additional wells and monitoring groundwater at Virginia City to comply with the CCR Rule. DENC is required to monitor these wells semi-annually. DENC continues to maintain compliance with its state permits and CCR Rule requirements related to its CCR units at the site. *Id.* at 91.

Yorktown

Yorktown began operation in 1957. Similarly to Chesapeake, the Company converted its coal-fired units to oil and then converted them back to burn coal in the 1980s. *Id.* at 141. In 1985, DENC constructed a lined solid waste landfill on an adjacent parcel of property owned by DENC. Since that time, the dry fly ash and bottom ash has been loaded on trucks and hauled to the adjacent CCR landfill. The Yorktown CCR landfill is permitted by the VA DEQ and is equipped with a bottom liner and leachate collection and treatment systems. *Id.* at 87.

The Company permanently closed over 60% of the landfill in 2017, and the remainder of the landfill will be permanently closed in 2019. *Id.* Witness Williams testified that the Company is closing its CCR facilities in accordance with state and federal requirements. *Id.* at 93.

In response to questions from the Commission witness Williams described DENC's CCR pond closure plans prior to the CCR Rule. He testified that at Possum Point the Company ceased using Ponds A, B and C in 1967. According to witness Williams, the ponds were left "in a static state." Witness Williams described this as placing soil over certain portions of the ponds where the Company needed access to equipment and infrastructure, such as transmission lines. No cover or cap was placed on the ponds. No vegetation was planted over the ponds. Any vegetation that grew in the ponds was natural regrowth that reseeded and spread. Further, no water was removed from the ponds. The water in the ponds was left to evaporate and migrate by what witness Williams described as "natural attenuation." Further, there was no groundwater monitoring of Ponds A, B and C, until it was required by the CCR Rule in 2016. Tr. vol. 5, 102-07, 124. Witness Williams testified that this same approach was taken by the Company at Bremo for the East Pond. He stated that the East Pond ceased receiving CCRs in the mid-1980s. *Id.* at 117-19. He further testified that this was the Company's closure plan for all of its CCR ponds, and that its plans were consistent with "regulatory allowed option[s]," until the CCR Rule and SB 1355 mandated different closure requirements. He stated that the Company had no written pond closure plans or written plans for post-closure activities.

Witness Williams further testified that there were no written Company documents evidencing an analysis of closure plan choices, or costs and benefits of different options, other than the plan developed for Chesterfield in the 1990s as a part of the NPDES permit. Tr. vol. 8, 20-25, 40-41. He also testified that prior to the CCR Rule the Company intended its CCR ponds to be "permanent disposal from the beginning." *Id.* at 41-42.

In addition, witness Williams testified that this same closure approach was taken by the Company at Possum Point Pond E when it was closed in 2003, with the exception that Pond E had groundwater monitoring wells installed in 1990, as required by its NPDES permit. *Id.* at 108-10.

Witness Williams described the Company's decision-making process in deciding to convert to lined dry ash landfills at Yorktown and Chesapeake in 1985, and at Clover when it was constructed in 1995. He stated that he was "not 100% sure" whether studies were conducted to determine the costs and benefits of converting to dry ash handling at other coal plants, but that he would make an inquiry. Tr. vol. 8, 50-55.

Witness Williams testified that the Company is a member of the Electric Power Research Institute (EPRI), and that the Company regularly consults EPRI publications "in some areas," although he had not worked directly with EPRI on coal ash. Tr. vol. 5, 129.

Witness Williams testified that the Company kept no records of the amount of CCRs deposited in its ponds annually or otherwise. He stated that DENC provided the Public Staff with estimates of the amounts of CCRs in its ponds based on the design and size information for each pond, and that this information was reflected in Lucas Exhibit 5. Tr. vol. 5, 146, 150-51.

In response to cross-examination by the Public Staff witness Williams stated that elevated concentrations of constituents were detected by DENC at Possum Point prior to the 1986 Virginia DEQ Special Order. Tr. vol. 5, 154.

With respect to Chisman Creek, witness Williams testified that shortly after 1974 the contamination was discovered at the site, and it was later placed in the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) program. He stated that DENC stepped in as the responsible party when the contractor that operated the site was not able to remediate it. Tr. vol. 5, 158.

Direct Testimony of Public Staff Witness Lucas

Public Staff witness Lucas recommended an equitable sharing of the Company's CCR management, remediation, and waste management unit closure costs. In conjunction with Public

Staff witness Maness, he recommended that 40% of these coal ash related costs should be paid by the Company's shareholders, and the remaining 60% be paid by ratepayers. Tr. vol. 6, 110.

Witness Lucas noted that the Public Staff's equitable sharing recommendation is not based on the prudence standard, which would have resulted in a 100% disallowance of imprudently incurred costs. *Id.* at 113. Witness Lucas explained that the Public Staff Advocated for an equitable sharing approach rather than a prudence review because "some impacts are not clearly imprudent or reasonable," "because estimating historic costs to remediate environmental impacts would be speculative," and "the incomplete records of DENC and the challenge of reconstructing all the Company's decision-making on CCR management make it difficult, if not impossible, to conduct a prudence review." *Id.* at 184-85. On cross-examination witness Lucas confirmed that he had not identified any specific CCR-related costs that the Company incurred or undertook between July 1, 2016, and June 30, 2019, that were imprudent or unreasonable. *Id.* at 298-99.

Witness Lucas explained that the Public Staff's equitable sharing recommendation is based in part on culpability for environmental contamination, *id.* at 113, and in part on the magnitude and nature of the costs, as discussed by Public Staff witness Maness. Witness Lucas stated that it would be unreasonable to charge ratepayers for all the Company's CCR-related costs where the Company, and not the ratepayers, is culpable for those costs. *Id.* at 186. Specifically, he stated that "DENC has culpability for non-compliance with environmental regulations that are meant to protect groundwater and surface water from contamination by CCR constituents," and that "DENC's past management of coal ash has resulted in a risk of future contamination that EPA and the Virginia legislature have determined requires costly new management and closure requirements." *Id.* at 112-13.

Witness Lucas discussed a set of historic academic, industry, and regulatory documents that "demonstrate that, by the early 1980s, the electric generating industry knew or should have known that the wet storage of CCR in unlined surface impoundments was detrimental to the quality of surrounding groundwater and surface water." *Id.* at 141-42. Specifically, he discussed a 1979 report published by a research group from Arthur D. Little, Inc., and the Industrial Environmental Research Laboratory of the EPA that found that CCRs stored in "[w]et impoundments have the potential for contributing directly to groundwater contamination;" and that lining impoundments would minimize such contamination. *Id.* at 142. Witness Lucas described the 1982 Manual for Upgrading Existing Disposal Facilities (EPRI Manual), published by the Electric Power Research Institute (EPRI), which stated that the use of surface impoundments "has fallen into disfavor with the EPA," and that "[w]hile groundwater can be protected and leachate generation can be minimized with sound engineering design and site operation, monitoring of groundwater and leachate, is nevertheless necessary to provide convincing proof of a safe disposal practice." *Id.* Witness Lucas testified that in 1988 the EPA issued a report to Congress in which it described how the use of liners, leachate collection systems, and groundwater monitoring had increased in the preceding years. *Id.* at 143-44. To illustrate this trend, he provided the following language from the 1988 report:

> Only about 25 percent of all facilities have liners to reduce off-site migration of leachate, although 40 percent of the generating units built since 1975 have liners. Additionally, only about 15 percent have leachate collection systems; about

> one-third of all facilities have ground-water monitoring systems to detect potential leachate problems. Both leachate collection and ground-water monitoring systems are more common at newer facilities.

Id. at 143.

Witness Lucas further stated that Dominion had failed to improve its CCR management practices despite the evolving knowledge of the risk of unlined CCR storage at the time. *Id.* at 144. According to witness Lucas, "[A]s publications from 1979 and later warned of the risks of CCR constituents leaching into groundwater from unlined storage ponds, DENC and other utilities should have installed comprehensive groundwater monitoring well networks to determine if the risk was materializing at their ash ponds." *Id.* He added that the Company had a duty to comply with groundwater quality standards regardless of accepted industry practice, noting Virginia and West Virginia's groundwater regulations and anti-degradation policies. *Id.* at 185. He explained that both Virginia and West Virginia have anti-degradation policies that require, broadly, that the quality of state waters be maintained. *Id.* at 125-26. Later, when asked during redirect examination, he read the anti-degradation policy from the Virginia Administrative Code into the record:

> If the concentration of any constituent in groundwater is less than the limit set forth by groundwater standards, the natural quality for the constituent shall be maintained. Natural quality shall also be maintained for all constituents, including temperature, not set forth in groundwater standards. If the concentration of any constituent in groundwater exceeds the limit in the standard for that constituent, no addition of that constituent to the naturally occurring concentration shall be made.

Id. at 306.

Witness Lucas stated that the Company had never installed voluntary groundwater monitoring wells at its coal-fired generating facilities and had only installed wells when required by state regulators to do so. *Id.* at 175. He testified that groundwater monitoring began at different dates for different sites, with monitoring beginning in the 1980s for some impoundments, in 2000 for impoundments at the Bremo facility, and as late as 2016 for historic Possum Point Ponds A, B, and C. These dates are shown on Lucas Exhibit 1. *Id.* at 175. He added that "DENC did not engage in comprehensive groundwater monitoring until even later," as shown on Lucas Exhibit 1. *Id.*

Witness Lucas confirmed on cross-examination that the Public Staff had not in the 1970s, 1980s, 1990s, or 2000s recommended that the Company install comprehensive groundwater monitoring, told the Company that its CCR management was not "sufficiently modern," or told the Company that it was not "sufficiently mitigating environmental impacts from its CCR impoundments or landfills." *Id.* at 299-300. Witness Lucas explained that "the Company, to my knowledge, didn't try to recover any costs like we're doing today that were created by groundwater contamination." *Id.* at 299.

Witness Lucas also testified regarding exceedances of groundwater standards at the Possum Point facility in the 1980s and discussed subsequent regulatory actions at that facility arising from those exceedances. *Id.* at 145-57. He explained that the facility had installed groundwater monitoring wells in 1985 as required in its National Pollutant Discharge Elimination System (NPDES) permit, and that samples from those wells had detected exceedances of groundwater standards in the vicinity of Ponds D and E. *Id.* at 145. Those exceedances resulted in a Special Order between the Virginia DEQ and the Company, which required further assessment of the contamination and an evaluation of remediation options. *Id.*

Witness Lucas also provided testimony regarding historic groundwater exceedances at the Chesapeake and Chesterfield facilities, as well as at the Chisman Creek CERCLA site, which witness Lucas explained was a site where a private contractor disposed of coal ash generated at DENC's Yorktown facility.[1] *Id.* at 157-63. Witness Lucas explained that at Chisman Creek the coal ash was disposed of in abandoned sand and gravel borrow pits between 1957 and 1974, and in 1980, when a neighboring well owner reported discolored water, the State Water Control Board found elevated levels of trace metals in groundwater, surface water, and soils. *Id.* at 162-63. Later, in 1986 and 1988, the EPA signed Records of Decision with objectives for remediation of the site. *Id.* at 163. He testified that the contamination affected drinking water to the level that the Company had to provide municipal water to nearby residents. He stated that this should have been an indicator to the Company that coal ash was capable of creating groundwater contamination. *Id.* at 337. Witness Lucas noted that the Chisman Creek site was mentioned in the preamble to the CCR Rule as an example of mismanagement of coal ash. *Id.* at 315.

Further, witness Lucas stated that these historic site investigations and exceedances "have shown evidence of degradation of the natural groundwater quality as a result of the Company's coal ash disposal practices." *Id.* He then testified that because of the absence of Company historical records concerning decisions made to construct new CCR waste management and disposal units or modify existing units, that the "Company is not able to demonstrate, with the records it has available, that it fully accounted for and mitigated the risks of CCR contamination in prior decades of CCR disposal and management." *Id.* at 165.

In addition, witness Lucas discussed groundwater contamination reported by the Company, and presented charts and maps of groundwater exceedances at each facility for the years 2017 and 2018 in Lucas Exhibits 12, 13, and 14. *Id.* at 176-79. He specifically noted 548 groundwater exceedances,[2] and explained that there will likely be additional exceedances reported due to inactive CCR surface impoundments now being required to collect and report groundwater monitoring data under the CCR Rule. *Id.* at 178-79. In response to questions from the Commission witness Lucas stated that the 548 groundwater exceedances showed statistically significant exceedances over natural background levels, maximum containment levels and/or groundwater protection standards. *Id.* at 308. He also explained on redirect examination that as the Company caused the groundwater to be degraded by failing to take steps to prevent leaching of ash constituents from its surface impoundments, it was in violation of the anti-degradation policies of

[1] Witness Lucas also briefly discussed exceedances at the Company's Yorktown facility, which he explained were "the result of current or historical activities upgradient of the land and facility wells." Tr. vol. 6, 162.

[2] Witness Lucas explained in his direct testimony that groundwater standards under the CCR Rule can differ from those adopted by Virginia and West Virginia. The standards in the CCR Rule are based on national maximum containment levels (MCLs) established by the EPA and are health-based.

Virginia and West Virginia. *Id.* at 306-07. Lastly, Witness Lucas noted that "[t]he lifetime compliance record for the Company's CCR impoundments is incomplete due in part to the lack of data retained by DENC," and that the Public Staff believes the Company had additional exceedances of groundwater standards at its CCR impoundments "over a long period of time." *Id.* at 179-80.

With respect to the Company's records witness Lucas testified that the Company was unable to locate and produce a number of historical NPDES/Virginia Pollutant Discharge Elimination System (VPDES) permits and groundwater monitoring reports and provided a list of missing documents. *Id.* at 168-72. He also testified that the records the Company was able to provide were not in a useful format, and that it was not possible from the Company's records "to identify all groundwater exceedances caused by CCR over the life of the Company's CCR units." *Id.* at 170-71. Witness Lucas also referred to a stipulation between the Company and the Public Staff, admitted as Lucas Exhibit 9, wherein the Company acknowledged its inability to provide historic records pertaining to groundwater conditions at its coal-fired generating facilities, as well as the fact that "it is not feasible to reconstruct a complete history of exceedances from Dominion's existing records." *Id.* at 172.

Witness Lucas summarized the following environmental legal actions filed against DENC:

> *Sierra Club v. VEPCO*, U.S. Court of Appeals, Fourth Circuit, Case No. 17-1895 (2018) – Plaintiff alleged surface water and groundwater violations at Chesapeake. The Fourth Circuit affirmed the trial court's conclusion that arsenic was reaching surface waters via groundwater, but held that the ash basins and landfill were not point sources under the Clean Water Act.
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> *In re James River Association* – Appeal by JRA from a decision of the Virginia DEQ issuing a modified VPDES permit allowing the discharge of wastewater from Bremo. VEPCO and JRA entered into a settlement in 2016, with VEPCO agreeing to guarantee a minimum amount of treatment for coal ash wastewater.
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> *In re Prince William County* - Appeal by PWC from a decision of the Virginia DEQ issuing a modified VPDES permit allowing the discharge of wastewater from Pond D at Possum Point. In 2016, VEPCO and PWC settled, with VEPCO agreeing to guarantee a minimum amount of treatment for coal ash wastewater.
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> *Potomac Riverkeeper Network v. State Water Control Board* – Appeal by PRN from a decision of the Virginia DEQ issuing a modified VPDES permit allowing the discharge of wastewater from Pond D at Possum Point. In 2016, the Circuit Court upheld the permit modifications and dismissed the appeal.
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> *State of Maryland v. State Water Control Board* – Appeal by Maryland from a decision of the Virginia State Water Control Board (VWCB) issuing a modified VPDES permit allowing the discharge of wastewater from Pond D at Possum Point.

In 2016, VEPCO agreed to stricter wastewater testing standards, and Maryland withdrew its appeal.

West, et al. v. VEPCO (VA Circuit Court) – In April 2018, two property owners adjacent to Possum Point filed complaints alleging groundwater contamination by coal ash ponds. The case is pending.

Id. at 131-36.

In concluding his discussion of the Public Staff's equitable sharing recommendation witness Lucas testified that the costs the Company has incurred for CCR management, remediation, and waste unit closure activities are related to groundwater contamination and environmental degradation. He stated that the CCR Rule and Virginia SB 1355 "were enacted in response to environmental contamination caused by CCR surface impoundments," and that the coal ash related costs the Company is seeking to recover are to comply with requirements that are "designed specifically to remediate ash basin environmental impacts that arose before the enactment of the CCR rule." *Id.* at 182. According to witness Lucas:

> DENC created the risk of coal ash contamination, their original disposal of CCR has led to actual environmental contamination in several instances, their original disposal of CCR poses an ongoing contamination risk that requires expensive remediation in the judgment of the EPA and the Virginia legislature, and ratepayers will not receive any additional electric service for this costly remediation.

Id. at 185.

When asked during cross-examination why the Public Staff's sharing recommendation in this case differs from those in the recent DEC and DEP rate cases, Docket Nos. E-7, Sub 1146 and E-2, Sub 1142, respectively — and specifically, why the Public Staff has found DENC to be less culpable than DEC and DEP — witness Lucas responded that DENC has not been found guilty of criminal negligence with respect to its management of waste coal ash facilities, has not had significant state regulatory enforcement actions, and that there is less evidence at this point of the extent of environmental impacts than were present in the DEC and DEP rate cases. *Id.* at 265.

Lastly, witness Lucas was asked on cross-examination whether the Public Staff are environmental regulators. *Id.* at 275. He responded that they are not and referred to a Public Staff response to a data request that stated the following: "The Public Staff is not a regulator. It is a consumer advocate working in a regulatory forum. . . . However, the costs of environmental compliance or the costs of non-compliance which the Company seeks to recover from ratepayers are within the jurisdiction of the Public Staff. . . ." *Id.* at 285-86. Witness Lucas was also asked about testimony submitted by a Public Staff engineer, Evan D. Lawrence, in a docket for an application for a Certificate of Public Convenience and Necessity for an electric merchant plant, in which witness Lawrence stated that "the Public Staff does not have particular expertise in the area of impacts of electric generation on the environment." *Id.* at 282-83. Witness Lucas explained that the cited testimony was taken out of context and was unrelated to cost recovery or a rate case. He further explained that witness Lawrence's testimony dealt with a certificate of public convenience and necessity for construction of a solar photovoltaic merchant electric generating facility, and that the purpose of his testimony was to discuss compliance of the application with applicable requirements, to discuss any concerns with the application, and to make a recommendation on the application to the Commission. *Id.* at 283-84.

Direct Testimony of Public Staff Witness Maness

Public Staff witness Maness described the Company's adjustments related to deferral of its CCR expenditures made to a regulatory asset. Those adjustments include: (1) the elimination of CCR-related accounting entries made in the Company's books and records during and before 2019 for financial accounting purposes; (2) a pro forma adjustment to increase rate base to defer as a regulatory asset the CCR expenditures incurred in the Deferral Period; and (3) a pro forma adjustment to increase operations and maintenance (O&M) expenses to reflect the three-year amortization of CCR expenditures. Tr. vol. 6, 209-10.

Witness Maness explained that for financial accounting purposes the Company has recorded its CCR expenditures as an Asset Retirement Obligation (ARO) liability, based on the requirements of Topic 410 (Asset Retirement and Environmental Obligations) of the Accounting Standards Codification (ASC 410) promulgated and maintained by the Financial Accounting Standards Board (FASB). *Id.* at 210-11. At the hearing witness Maness explained that when an ARO is established for financial accounting, the Company makes estimates of future costs and then "they basically discount that to be the present value as of today, using an appropriate discount rate, and they put that on their financial statements for financial investor purposes as a liability." *Id.* at 253. He further explained that at the same time the Company establishes the ARO it establishes an asset retirement cost (ARC) as an asset on its balance sheet. Next, to flow the ARC through expense over a period of time, the Company will depreciate it into the future in future financial statements using a depreciation method, or, if it's a retired asset such as a coal plant, the Company writes it off to expense immediately. *Id.* at 254. As an example, witness Maness stated:

> [I]n some cases, you may have an asset retirement obligation for a generating plant where the actual expenditures are not going to take place until many years into the future. So in that case, they will go ahead and record expenses -- they'll depreciate over the life of the plant. And they will incur those expenses at some future time, but they --or those expenditures, but they will be recording an expense as they go along without actually spending any cash at all. In other cases, you may have, such as we have for some of the coal plants involved here, plants that have already been retired. And so they still may not make those expenditures for some time into the future, but they will go ahead and immediately, for financial statement purposes, record the entire asset retirement cost related to that plant as an expense in the period in which it arises.

Id. at 255-56.

Witness Maness explained that, in this proceeding, the Company has reversed the entries made on its books in association with the FASB-mandated CCR ARO liability and is proposing the deferral and amortization of actual expenditures made during the Deferral Period, in accord with standard ratemaking accounting practice. He stated that the Company followed a similar procedure for CCR expenditures in the 2016 DENC rate case, and that the Public Staff agreed in concept with the Company's deferral approach in 2016 and, at that time, entered a Stipulation with the Company, which was approved by the Commission. Witness Maness testified that the terms of the Stipulation expressly stated that it did not prejudice the right of any party to take issue with the amount or treatment of any deferral of ARO costs in a future rate case proceeding. Given the magnitude of the costs involved in this proceeding, witness Maness stated that the Public Staff believes that continued deferral has been reasonable. *Id.* at 214.

In this proceeding witness Maness recommended the following adjustments to the Company's CCR expenditures:

1. Calculation of the return between July 1, 2016, and June 30, 2019, using annual compounding, rather than monthly compounding;

2. Amortization of the balance of deferred coal ash expenditures as of June 30, 2019, over a 19-year period [later updated to 18 years], rather than the 3-year period proposed by the Company; and

3. Reversal of the Company's inclusion of the unamortized balance of coal ash expenditures in rate base. This reversal, in conjunction with the 19-year amortization period, produces an equitable and reasonable sharing of the burden of coal ash expenditures between the Company's ratepayers and its shareholders.

Id. at 215-16.

Witness Maness stated that the Company's recommended amortization period is too short for costs of the magnitude and nature of CCR costs. Further, he noted that his recommendation for a longer amortization period, when coupled with the exclusion of the unamortized balance from rate base, would result in an equitable sharing of the costs between shareholders and ratepayers.

Witness Maness stated that there are two general reasons why the equitable sharing of CCR costs is appropriate in the present case. The first reason is that some degree of equitable sharing is appropriate because DENC has culpability for past environmental contamination and for creating a risk of future contamination from coal ash as discussed by Public Staff witness Lucas. The second reason is that some level of sharing is appropriate and reasonable because of the magnitude and nature of the costs. *Id.* at 218-19.

Witness Maness testified that equitable sharing of certain costs is appropriate without a specific finding of imprudence. He stated several reasons why equitable sharing is appropriate for CCR expenditures, including:

- The total amount of the costs is large (approximately \$377 million on a system level and approximately \$22 million on a North Carolina retail level), which amounts to approximately \$179 per North Carolina retail customer, or \$60 per year per North

Carolina retail customer, before considering the impact of including the unamortized amount in rate base.

- DENC will be incurring significant additional costs in the future related to the CCR Excavation Act (Virginia Senate Bill 1355).
- The incurrence of these costs will not provide any benefits to customers in terms of additional electric service or improvements to service.
- The incurrence of CCR costs has not been the result of economic analysis that pointed toward an action that would be economically advantageous to ratepayers.
- And finally, he noted that the Commission has implemented equitable sharing in several past circumstances involving incurred costs that did not provide any future benefits to retail customers.

Id. at 220-22.

Witness Maness stated that the circumstances of this case, including the culpability of the Company and the magnitude and nature of the costs, as well as the levels of sharing approved by the Commission in past cases, led the Public Staff to its recommendation that shareholders bear 40% of the Deferral Period CCR costs (which results in a 19-year amortization period based on the rate of return initially recommended by the Public Staff, or an 18-year amortization based on the stipulated rate of return). Witness Maness stated that the Public Staff would likely recommend some level of sharing of costs even in the absence of culpability due to the magnitude and/or nature of the costs involved.

Witness Maness explained that the Public Staff's equitable sharing is achieved by first removing the unamortized amount of deferred expenses from rate base. As a result of that adjustment, the Company would not be allowed to earn a return from ratepayers on the unamortized balance while the deferred costs are being amortized.[1] The second step is to choose an amortization period that will result in a reasonable and appropriate sharing of the costs over time. *Id.* at 222. Maness Late-Filed Exhibit 1 shows the sharing percentages achieved by five- and ten-year amortization periods, in addition to the 18-year amortization period recommended by the Public Staff in witness Maness' supplemental testimony.

Relying on advice of counsel, witness Maness testified that excluding deferred expenses or losses from rate base is legal under North Carolina law. The Public Staff's position is that the only costs the Commission is required to include in rate base pursuant to N.C.G.S. § 62-133(b)(1) are the public utility's property that is used and useful, or, in some circumstances, the costs of construction work in progress. Again relying on advice of counsel, witness Maness stated that N.C.G.S. § 62-133(d) operates separately from N.C.G.S. § 62-133(b), and requires the

[1] As discussed elsewhere in this Order, the Public Staff agrees with allowing recovery of financing costs incurred between the beginning of the Deferral Period and the date rates approved in this proceeding become effective (when amortization begins).

Commission to "consider all other material facts of record that will enable it to determine what are reasonable and just rates." The Public Staff asserted that N.C.G.S. § 62-133(d) provides the Commission with discretion to authorize equitable sharing where appropriate to achieve reasonable and just rates. *Id.* at 223.

Witness Maness explained that the Commission has approved equitable sharing in several past cases, including in the cases of plant abandonment losses. Specifically with regard to DENC, witness Maness stated that the Commission has found that a ten-year amortization period, with no return, was appropriate to fairly allocate the loss between the utility and the consumer for Surry Unit 3, Surry Unit 4, North Anna Unit 3, and North Anna Unit 4. *Id.* at 223-25; *see* Docket No. E-22, Sub 273, Seventy-Third Report of the North Carolina Utilities Commission, pp. 354-55. Furthermore, witness Maness incorporated by reference the North Carolina Supreme Court decision affirming the equitable sharing of costs between ratepayers and shareholders with regard to Carolina Power & Light Company's (CP&L) Harris plant cancellation costs. Tr. vol. 6, 226-28; *see State ex. rel. Utilities Com. v. Thornburg*, 325 N.C. 463, 385 S.E.2d 451 (1989).

Witness Maness testified that the Commission has also found that an equitable sharing of costs was appropriate for the environmental cleanup costs associated with manufactured natural gas plants (MGPs) in its October 7, 1994 Order Granting Partial Rate Increase in Docket No. G-5, Sub 327. Tr. vol. 6, 228. The MGP sites were the subject of "investigations under environmental laws." According to witness Maness, the Commission ordered an equitable sharing for the environmental cleanup costs of Public Service Company of North Carolina, Inc., (PSNC), and specifically found:

> 29. The unamortized balance of MGP costs should not be included in rate base. The resulting sharing of clean-up costs between ratepayers and shareholders will provide PSNC motivation to minimize costs and to pursue contributions from other potentially responsible parties and insurers.

Order Granting Partial Rate Increase, *Application of Public Service Company of North Carolina, Inc., for an Adjustment of its Rates and Charges*, No. G-5, Sub 327, at 6 (N.C.U.C. Oct. 7, 1994) (MGP Order).

Turning to whether the CCR costs are used and useful, witness Maness explained that "used and useful" only applies to a utility's property and not to a utility's expenses incurred in the operation, maintenance, and disposal of that property. Tr. vol. 6, 229-30. Witness Maness argued that DENC's deferred CCR costs are not "property used and useful" under N.C.G.S. § 62-133(b)(1) because (1) most of the costs in this case were incurred for operating expenses, and (2) the Commission authorized deferral of those expenditures to a regulatory asset. In particular, he testified that:

> (1) In data responses to the Public Staff, the Company has stated that the vast majority of the CCR expenditures made from January 2015 through June 2019 would be charged to expense if the FASB and FERC USOA [Federal Energy Regulatory Commission Uniform System of Accounts] ARO accounting requirements did not exist.

> (2) Even for those items that might be capitalized costs of property in the absence of the FASB and FERC USOA ARO accounting requirements, the Company has itself chosen to request a regulatory accounting and ratemaking method that does not explicitly account for any coal ash compliance costs, either in the past or in the future, as the capitalized costs of property, but instead accounts for them as expenses, with a proposed regulatory asset intended to provide for the recovery of expenses incurred in the past. Although the Company could have chosen to propose following a different method, whereby it might specifically identify capital costs separately and include them in rate base, depreciating them over their useful lives, while accounting for other expenses on an ongoing basis, it did not. Instead, the Company has proposed to utilize an accounting and ratemaking model that accounts for and recovers the coal ash cleanup costs as expenses on an as-spent basis, without specific identification of, or accounting for, any costs as plant in service or other property.

Id. at 231-32.

In addition, witness Maness addressed the issue of whether the classification of the deferred CCR costs as "working capital" is appropriate. Witness Maness stated that in his opinion the classification is a matter of convenience and the "proposed deferred coal ash compliance costs are expenses incurred in the past that the Company proposes to recover in the future; they have nothing to do with the Company's forward-looking obligation to provide utility service." *Id.* at 232. To clarify the appropriate scope of working capital, witness Maness provided the following description from Charles F. Phillips, Jr. in his treatise on utility regulation:

> Working capital – the funds representing necessary investment in materials and supplies, and the cash required to meet current obligations and to maintain minimum bank balances – is included in the rate base so that investors are compensated for capital they have supplied to a utility.

Id.; *see* Charles F. Phillips, Jr., *The Regulation of Public Utilities 348* (3d ed. 1993). Since the CCR deferred costs neither enable nor facilitate the provision of current or future utility service, consistent with the Charles Phillips definition, witness Maness asserted that those costs cannot be classified in substance as "working capital," and thus are not required to be included in rate base.

Witness Maness testified that when a return is denied on coal ash costs, the degree of sharing is a function of the length of the amortization period: "as the delay in the recovery period increases, the utility's financing costs increase, and the burden of the loss of the time value of money on the ratepayers decreases." Tr. vol. 6, 234. To achieve a sharing that results in ratepayers bearing approximately 60% of the present value of deferred costs at the net-of-tax overall rate of return witness Maness recommended, in his direct testimony, a 19-year amortization period. *Id.* at 235.

Witness Maness stated that the 60%-40% sharing ratio is a qualitative judgment that the Public Staff believes is reasonable and appropriate based on the magnitude and nature of the costs and the extent of DENC's culpability for coal ash environmental contamination, as addressed in the testimony of witness Lucas. *Id.* The recommendation for a lesser sharing burden on investors in this case than was recommended in the recent DEC and DEP rate cases (approximately 50%-50% sharing) is based on the lesser extent of environmental contamination attributable to DENC's coal ash waste management units, as determined by witness Lucas.

Witness Maness additionally stated that the Public Staff would very likely recommend some level of sharing even in the absence of environmental culpability, due to the magnitude and/or nature of the costs. *Id.* at 237-38. In DENC's Sub 532 general rate case, the Public Staff agreed to an amortization period of five years with the unamortized balance included in rate base. However, at that time the total paid-to-date system costs were only 22% of the system-wide Deferral Period CCR costs at issue in this case. Additionally, as described by witness Lucas, there was almost no evidence in the Sub 532 record of environmental problems created by DENC's coal ash storage facilities, in contrast to the present case. *Id.* at 238-39.

In supplemental direct testimony Public Staff witness Maness adjusted his sharing recommendation amortization period from nineteen years to eighteen years based on the Public Staff Stipulation. *Id.* at 246. He explained that the overall rate of return agreed to in the Stipulation affects the number of years of amortization needed to achieve the recommended sharing allocation. Due to the increase in the rate of return from that initially recommended by the Public Staff, the amortization period necessary to achieve an approximate 60%-40% sharing decreased to eighteen years. The sharing percentage is approximate: eighteen years produces a ratepayer sharing of 59.212%, which is the closest to 60% sharing that can be achieved using the stipulated rate of return and whole years without the ratepayer portion exceeding 60%. *Id.* at 247.

Witness Maness also adjusted the North Carolina jurisdictional amount of the CCR deferred costs to reflect the compounding of DENC's return on those costs on an annual basis, as agreed to by DENC, rather than on a monthly basis, as initially proposed by DENC. The adjusted North Carolina jurisdictional amount is $21,841,000. Maness Supplemental Exhibit 1, Schedule 1.

Rebuttal Testimony of DENC Witness Williams

Company witness Williams' rebuttal testimony responded to the direct testimony of Public Staff witnesses Lucas and Maness regarding the Public Staff's recommended "equitable sharing" disallowance. Witness Williams observed that the Public Staff's disallowance theory largely rests on its opinion that DENC was "culpable" for creating a risk of groundwater contamination that has led to actual environmental contamination attributable to the Company's CCR waste management facilities. Tr. vol. 7, p. 52. He also noted that the Public Staff argued that "equitable sharing" would be appropriate even without "culpability" solely because of the magnitude of DENC's requested costs. According to witness Williams "culpability" suggests wrongdoing. He noted that the Public Staff has acknowledged that it is not capable of or willing to identify a specific action the Company could have taken in the past, and that witness Lucas previously testified in the

2018 DEP Rate Case, in which the Public Staff also recommended equitable sharing based on DEP's historical ash management practices:

> We can't go back in time and say, oh, they should have put in a clay liner in 1978 or done dry ash stacking in the 1980s. I mean, that's impossible to go back and put all these "what ifs" together and say exactly here's what they should have done. And here's what would have been the cost, and that cost would have been in the rates today for customers.
>
> . . .
>
> [T]hat's going back to the past. Somebody could have gone back and said what you should have done back at a certain time. And that's — you could be talking about the prudence, and I can't go back and — I can't go back and tell you exactly what would have happened what you should have done at a certain time. I'm not sure what good it would have done . . . .

Id. at 52.

Witness Williams contended that this case should be focused on determining whether the identifiable CCR costs that the Company incurred from July 1, 2016 through June 30, 2019, were the result of reasonable and prudent decisions made at the time the costs were incurred. He maintained that DENC's costs are reasonable and prudent because the Public Staff did not recommend a single, specific cost disallowance related to DENC's CCR impoundments or landfills. *Id.* at 56.

Witness Williams also questioned whether it was within the Public Staff's purview and scope of expertise to evaluate the Company's compliance with environmental regulations and standards. He noted that neither the Company nor the Public Staff could find any example prior to 2016 where the Public Staff had raised any concerns regarding groundwater or surface water issues related to CCR or CCR management strategies at any of DENC's facilities. *Id.* at 57-58; Company Rebuttal Exhibit JEW-1. He noted that it has been the Public Staff's position that it is not an environmental regulator, and environmental regulation of DENC's CCR impoundments and landfills is the responsibility of state agencies such as the Virginia DEQ and West Virginia DEP, and that when a utility complies with the directives of its environmental regulators, it has been the position of the Public Staff that such actions would not be considered mismanagement. Witness Williams testified that if the Public Staff's role did not involve evaluating the Company's CCR management practices when the management decisions were made, the Public Staff cannot argue that its role in the present case involves second-guessing the decisions of the Company and its environmental regulators decades later. Tr. vol. 7, 59.

Witness Williams further questioned the Public Staff's role and expertise regarding environmental issues in light of testimony submitted by the Public Staff in May 2019 in Docket No. EMP-103, Sub 0. In that case, Albemarle Beach Solar, LLC applied for a certificate of public convenience to construct an 80-MW solar facility in Washington County, North Carolina. An issue in the docket was the potential environmental impacts of the solar project. According to witness Williams, the Public Staff did not opine on those potential environmental issues and testified:

> [T]he Public Staff does not have particular expertise in the area of impacts of electric generation on the environment. Those issues are best left to the purview of environmental regulators who do have this expertise, and who are responsible for issuing specific environmental permits for electric generating facilities. To that end, as stated below, the Public Staff recommends that the Commission require compliance with all permitting requirements . . . .

Id. at 59-60.

Witness Williams noted that the Public Staff witness who offered the testimony in Docket No. EMP-103, Sub 0 held the same position within the Public Staff – Utilities Engineer, Electric Division – as witness Lucas. Based on the Public Staff's statements about its role and the scope of its expertise, witness Williams opined that witness Lucas' testimony was unreliable. *Id.* He also commented that the Public Staff's recent attempts to take on the role of a hindsight environmental regulator would promote inefficiency and inconsistency within the utility industry. It would be inefficient because environmental regulators already consider and understand the potential impacts of their decisions, such as when and to whom to issue permits, when and where to require and not require groundwater monitoring, or how potential impacts, if manifested, should be addressed. The Public Staff is attempting to second-guess those efforts but without the requisite level of expertise. It would promote inconsistency because having utilities be subject to the Public Staff's hindsight environmental review would potentially undermine the decisions, judgment, and expertise of environmental regulators. *Id.* at 62.

Witness Williams also responded to the Public Staff's criticisms of his expertise and ability to testify regarding historical CCR management decisions made by the Company. He testified that those criticisms are unfounded. He testified that he was a professional geologist with almost twenty years of groundwater remediation and waste management experience. This experience included five years that he spent with VA DEQ, where he was the lead staff on reviewing coal ash regulations following the TVA dam failure in 2008. His role was to not only provide expertise in coal ash, but to also provide guidance regarding Virginia's groundwater requirements and their history. Witness Williams testified that while at the Company he has also become proficient in West Virginia's groundwater regulations and their application to DENC's Mt. Storm facility. Since the Public Staff's recommended disallowance is largely based on alleged groundwater issues at DENC's sites in Virginia and West Virginia, he explained that he was extremely well-qualified to explain the Company's CCR management decisions with respect to groundwater in those states. Additionally, he explained that he was well-positioned to discuss the history of CCR management at DENC's facilities. In his role as Director of Environmental Services, he was responsible for overseeing environmental compliance at all of DENC's coal-fired plants. That role required that he understand how those plants and CCR storage facilities have been historically operated. Additionally, he reviewed historical regulatory reports as well as the studies cited by witness Lucas and explained that he was well-qualified to understand those materials in their proper context and to draw meaningful and reasoned conclusions from them. *Id.* at 60-61.

Witness Williams next addressed witness Lucas' criticisms and characterizations of DENC's historical CCR management practices and environmental compliance history. Witness Williams disagreed with witness Lucas' contention that the electric generating industry knew or should have known that wet storage of CCR in unlined surface impoundments was detrimental to the quality of surrounding groundwater and surface water. He observed that none of the articles, reports, or studies cited by witness Lucas condemn or recommend the elimination of the use of unlined impoundments. Further, he explained that unlined surface impoundments are not by their very existence "detrimental" to groundwater and nearby surface water. He explained that EPA reports from the 1980s through the 2000s show that site specific and regional factors must be considered to evaluate potential impacts to water quality from surface impoundments. In addition, he stated that if impacts are discovered that does not mean that the public or environmental health has been threatened. *Id.* at 64-65.

Witness Williams testified that much context was missing from witness Lucas' testimony regarding the Company's historical management practices. He opined that the Public Staff's testimony was devoid of any qualitative analysis of the evolving knowledge of potential impacts from CCR management practices. He explained that understanding the extent and nature of potential impacts is crucial to determining whether the Company adequately managed its CCR. He also testified that one should consider how different actions may have impacted DENC's ability to reliably generate electricity to meet demand and other economic impacts. While surface impoundments are now being regulated out of existence, witness Williams explained that surface impoundments were originally constructed as an environmental solution to address concerns about air emissions from coal-fired plants. Those concerns resulted in the adoption of emission control technologies to collect CCR, which previously would have been emitted into the air, and direct the CCR via water to surface impoundments serving a water treatment function. According to witness Williams, EPA's approach to regulating CCR has evolved significantly over time, ultimately culminating in the CCR Rule. *Id.* at 65-66.

To show that evolution, witness Williams summarized the major federal regulatory determinations and reports affecting CCR from the 1970s through the promulgation of the CCR Rule. Those determinations and reports reflected EPA's findings after considering the available scientific and industry knowledge. Witness Williams testified that, until the CCR Rule, EPA's position was to defer to state agencies, like VA DEQ and WV DEP, to regulate CCR and determine whether industry practices were sufficiently protective of the environment. He testified that it was not until 2010, when the draft CCR Rule was published, that EPA first proposed actions to address potential environmental risks from unlined surface impoundments. According to witness Williams, that is because prior to the CCR Rule EPA had concluded that a one-size-fits-all federal regulatory approach was not deemed necessary to address region-specific conditions and risks. Even then, one of EPA's proposals would have allowed the continued use of unlined surface impoundments until they reached the end of their useful lives. *Id.* at 65-73.

Witness Williams opined that DENC responded reasonably and appropriately to evolutions in industry practices and regulatory approaches for CCR management by following the directives of its state regulators. Witness Williams described the regulatory regimes in Virginia and West Virginia that were applicable to its CCR surface impoundments and landfills. He explained that Virginia first adopted groundwater regulations in 1977. From 1977 until 1998, Virginia DEQ's regional offices evaluated groundwater risks at CCR facilities through requirements placed in the Company's VPDES, Virginia Pollution Abatement (VPA) permits, and solid waste permits. Additionally, he explained that local governments were also able to require groundwater monitoring through conditional use permits issued for certain CCR storage facilities. He testified that in 1998, VA DEQ developed a policy (the 1998 VA DEQ Guidance) to promote consistent standards amongst its six regions, which included guidance on when to require groundwater monitoring, how monitoring wells should be installed, the parameters that should be considered for monitoring, the proper methods for collecting and analyzing samples, determining the need for and execution of risk assessment, and selecting remedial methods, if needed. He explained that under the 1998 VA DEQ Guidance ultimate responsibility for determining whether groundwater monitoring was necessary was delegated to the permit writer, who was a member of the Virginia DEQ staff with specialized expertise. If groundwater monitoring was determined to be necessary, the permit writer could require DENC to develop a groundwater monitoring plan (GWMP). Witness Williams testified that Virginia DEQ adopted a phased approach for groundwater monitoring. The first phase would typically involve a small number of wells (minimum of one upgradient and two downgradient). If potential groundwater impacts were detected during the first phase, a second phase with additional monitoring wells could be required. He testified that based on the groundwater monitoring data received (i.e. constituents, detected levels, extent of plume, proximity of plume to receptors), Virginia DEQ could then determine whether a risk assessment was necessary. If Virginia DEQ identified a potential risk, then it could require remedial action, which could range from requiring closure, excavation, or lining of surface impoundments. However, he explained that Virginia DEQ would have selected a remedial option that was commensurate with the risks posed by the potential impacts. If impacts or potential off-site risks were deemed not to be harmful, Virginia DEQ could determine that leaving the groundwater alone (i.e. natural attenuation) at that point may be all that is necessary. *Id.* at 74-75. Similarly to Virginia DEQ, the West Virginia DEP was responsible for overseeing the State's solid waste program applicable to CCR storage. As of 1987, all CCR disposal sites in West Virginia were required to meet leachate, waste confinement, and aesthetic standards, and there were provisions for groundwater monitoring and final cover requirements. *Id.* at 76.

Witness Williams testified that by 1988, when the EPA published its report to Congress, DENC was monitoring groundwater at all but one of its active Virginia stations pursuant to Virginia DEQ requirements and standards. He testified that by 2000 the Company was monitoring groundwater at all of its Virginia stations, and that at the Company's Mt. Storm facility in West Virginia, groundwater monitoring began in 1987 after DENC received its NPDES permit to construct the CCR landfill. Witness Williams stated that similar to the approach taken in Virginia, an exceedance of a groundwater standard in West Virginia was not managed as a violation warranting a penalty. Instead, DENC would have been required to take additional steps to evaluate groundwater quality, including increasing the frequency of sampling, adding parameters to monitor, and assessments for potential remedial action. Witness Williams explained that West Virginia DEP never required corrective action for groundwater exceedances. *Id.* at 75-77.

Based on what he described as the robust regulatory oversight that was in place in Virginia and West Virginia and DENC's compliance with regulatory directives, witness Williams disagreed with witness Lucas' contention that the Company did not install comprehensive groundwater monitoring well networks to evaluate potential groundwater impacts from CCR surface impoundments. He noted that witness Lucas did not explain what he meant by "comprehensive monitoring" or how it would differ from what the Company had already been doing, and that witness Lucas provided no meaningful and necessary details to explain what "comprehensive monitoring" should have occurred, including how many background and monitoring wells should have been installed, the location of wells, the constituents to be monitored, or the frequency of testing. *Id.* at 78-79. Further, witness Williams noted that witness Lucas did not explain why Virginia DEQ and West Virginia DEP's judgment regarding the necessity for and scope of groundwater monitoring should be ignored in favor of witness Lucas' undefined, hindsight standard. Considering that DENC's state environmental regulators did not believe that installing extensive groundwater monitoring networks was necessary or appropriate for all sites, witness Williams questioned whether DENC's economic regulators, including this Commission and Virginia State Corporation Commission, would have deemed costs to install and monitor unnecessary wells to be reasonable. *Id.* at 80.

Witness Williams explained that DENC and its state regulators took a measured approach to assess and mitigate potential risks from CCR storage facilities. He testified that DENC collected groundwater data in accordance with its environmental permits, and it submitted that data to its environmental regulators for review and analysis. In the event of exceedances he explained that regulators on some occasions used their expertise and professional judgment to require further action, including increasing monitoring frequency, increasing the number of constituents to be sampled, requiring the installation of new wells, or requiring the preparation of site characterization studies to evaluate potential risks. Witness Williams testified that in all cases the Company complied with any additional actions required by its environmental regulators to mitigate risks and protect the environment. He noted that for all of DENC's lined and unlined surface impoundments, state environmental regulators reissued permits allowing the Company to continue to dispose and store CCR in those impoundments. He opined that had environmental regulators determined that DENC's CCR storage areas posed a threat to human health or the environment, they would not have continued to renew those operating permits and would have required more corrective actions. *Id.* at 80-81. Witness Williams also testified that witness Lucas could not explain how groundwater monitoring different than what had been historically required by Virginia DEQ and West Virginia DEP (i.e. "comprehensive groundwater monitoring well networks") would have changed the Company's CCR management practices or avoided the present-day costs that the Company is seeking to recover in this case. *Id.* at 81-82.

Witness Williams also responded to witness Lucas' contention that DENC, as an industry leader, was responsible for setting the industry standards. Although witness Lucas was apparently critical of those industry standards, witness Williams noted that witness Lucas did not explain or define what the industry standard should have been, nor did he argue that DENC's compliance with the industry standard and applicable laws was unreasonable or irrelevant. According to witness Williams, witness Lucas insinuated that DENC should have moved well ahead of accepted science, regulatory requirements, and industry practice by taking unspecified measures to prevent any and all groundwater quality impacts regardless of cost, despite likely interruptions to electric service, and without evidence of any potential harm to human health or the environment. *Id.* at 83.

Witness Williams rejected witness Lucas' assertion that the Company was or should have been aware of environmental degradation caused by its CCR because of environmental studies that were conducted at Possum Point, Chesapeake, Chesterfield, and Yorktown. Witness Williams opined that the existence of exceedances, alone, did not mean that the Company harmed the environment or otherwise mismanaged its CCR. He explained that the existence of past and present groundwater exceedances reflects historical construction practices and the evolution of groundwater assessment and corrective action under modern laws. He testified that EPA was aware that the design of ash basins had resulted in groundwater concerns throughout the industry; however, EPA determined that immediately closing basins, which would require shutting down operating coal plants, would be more harmful to human health and the environment than taking a measured approach. Witness Williams testified that DENC's state regulators focused on whether the exceedances were causing, or had the potential to cause harm to, any on- or off-site receptors to determine whether mitigation measures were necessary. The existence of an exceedance of applicable standards at a particular location was not evidence of actual or potential harm; rather, it was a data point that informs whether and to what extent further study is required to assess potential risk. Witness Williams cited the 1998 Virginia DEQ Guidance which stated that "risk assessment ultimately determines whether some measure of remediation needs to be completed." He then pointed out that none of the reports cited by witness Lucas indicated any risk to offsite human health or ecological receptors. *Id.* at 83-86.

Witness Williams testified that the reports cited by witness Lucas actually show that DENC was diligently monitoring groundwater to determine whether further mitigation measures were necessary. He testified that when Virginia DEQ did require follow-up measures the Company took appropriate measures. He rejected witness Lucas' contention that the Company did not follow the directives of its regulators regarding groundwater issues at Possum Point. He pointed out that witness Lucas' own exhibit showed that the Company did, in fact, comply with a Special Order issued by the State Water Control Board, which was confirmed by the cancellation of that order in 1991. Witness Williams also clarified that the report relating to groundwater issues at Yorktown that was cited by witness Lucas had nothing to do with CCR. *Id.* at 84-85. Regarding witness Lucas' reference to Chisman Creek and the Battlefield Golf Club site, witness Williams testified that those sites were irrelevant to the issues in this case because neither site is subject to the CCR Rule, neither site was owned by DENC when contamination occurred, and neither site managed CCR in surface impoundments or landfills. *Id.* at 86-88. Likewise, witness Williams testified that the legal matters cited by the Public Staff were also irrelevant and misleading because witness Lucas did not argue that the existence of those cases was evidence of wrongdoing, mismanagement or harm to the environment. *Id.* at 88-89.

Witness Williams also responded to the Public Staff's criticisms of the discovery process, which he opined was merely a distraction. He represented that he and his staff made good faith efforts to locate, collect, and then produce information and documents spanning almost four decades of the Company's operations. He estimated that DENC employees spent over 250 hours searching for and collecting information, culminating in the production of decades' worth of CCR-related documents to the Public Staff. He noted that the Public Staff never filed a motion to compel, despite claiming DENC's responses were inadequate. He also testified that he was not aware of any legal requirement or business reason to retain decades-old permitting materials, especially when the Company could not have foreseen that the Public Staff would, decades after the CCR storage facilities were constructed, be scrutinizing the Company's historical CCR management practices. Witness Williams explained that witness Lucas' testimony regarding purported examples of discovery deficiencies and instances of non-responsiveness was misleading, irrelevant, and false. *Id.* at 89-92.

Witness Williams also rejected the Public Staff's claim that it did not have enough information to evaluate the Company's environmental compliance history. As the Public Staff did not conduct a prudence review, nor did it have any intent to do so, it was unclear to witness Williams how additional information regarding historical CCR management decisions would have been helpful or relevant to the Public Staff. Responding to witness Lucas' testimony regarding the lack of groundwater reports prior to 2000, witness Williams testified that DENC did provide the Public Staff with a spreadsheet showing all of the approximately 300,000 groundwater monitoring results going back to the beginning of monitoring for each site, each of which would have been provided to VA DEQ or WV DEP. He opined that DENC's compliance history could be judged by its regulators' response to those monitoring results:

- DENC's environmental regulators did not require the Company to retrofit its existing impoundments with liners;
- DENC's environmental regulators did not require the Company to close its existing impoundments;
- DENC's environmental regulators did not require the Company to excavate CCR from its existing impoundments;
- DENC's environmental regulators authorized the Company's continued use of its existing impoundments;
- DENC's environmental regulators authorized the Company to continue disposing of CCR in its existing impoundments; and
- DENC's environmental regulators, where potential groundwater impacts were identified, required further monitoring, risk assessments, or corrective action.

He testified that, while Virginia DEQ and West Virginia DEP had the authority to do so, they never saw a sufficient environmental justification for requiring DENC to change its CCR management practices. Further, he opined that in the absence of any environmental justification the Company would not have been able to make an economic justification to its shareholders and customers for overhauling its operations. He testified that the Public Staff's assertion that "missing" groundwater data would have shown additional evidence of degradation was speculation, was not scientifically supported, and was not consistent with the regulatory record. Moreover, he testified that it would be speculation built on speculation to suggest that additional evidence would have triggered any different action by environmental regulators or the Company. He opined that recent groundwater data collected under the CCR Rule, which did not show risks to human health or the environment, confirmed that additional data would not have spurred state regulators to require changes to the Company's CCR management practices. *Id.* at 92-94.

Witness Williams concluded his rebuttal testimony by showing that the Public Staff's hindsight review of the Company's historical CCR management practices was unfair and not productive. He noted that the Public Staff and the Commission knew about and never objected to the continued use of surface impoundments and landfills in North Carolina. He explained that burning coal and storing the by-products was essential to providing reliable electricity in the region for decades. Witness Williams conceded that present and future CCR costs were significant but that the Company was minimizing those costs to the degree possible. He expressed his concern that the Public Staff's recommended disallowance of admittedly prudent and reasonable costs through "equitable sharing" was shortsighted and could lead to an unpredictable and unhealthy regulatory environment for utilities and their customers. *Id.* at 96-97.

Rebuttal Testimony of DENC Witness McLeod

Witness McLeod noted that the Public Staff agrees and makes no objection to the Company's ongoing deferral accounting treatment of CCR costs. Tr. vol. 6, 665. He also addressed each of the Public Staff's three recommended adjustments set forth in the testimony of witness Maness. First, he stated that the Company accepts as reasonable the Public Staff's recommended adjustment to use annual compounding rather than monthly compounding for financing costs incurred on CCR ARO expenditures during the deferral period of July 1, 2016 through June 30, 2019. Witness McLeod noted that this change reduces the Company's Adjustment NC-33 by $23,000. *Id.* at 667.

Witness McLeod next explained the Company's opposition to witness Maness' purported justification for the Public Staff's proposed equitable sharing approach. As a threshold matter, witness McLeod noted that neither witness Lucas nor witness Maness identified any specific CCR-related costs that the Public Staff alleges to be imprudent or unreasonable. *Id.* at 667. Witness McLeod underscored that the appropriate regulatory standard for denial of cost recovery is a finding that a specifically identified cost has been imprudently incurred or that the level of cost incurred is unreasonable. In the absence of an allegation of imprudence or unreasonableness, witness McLeod found the Public Staff's proposal to be "standard-less," subjective, and inappropriate. *Id.* at 669. For example, witness McLeod noted that the Public Staff can point to no methodology that would support its selection of the proposed 60/40 sharing split. Noting witness Maness' concession that the Public Staff subjectively selected a sharing ratio, then "backed into" the mechanism necessary to achieve that level of disallowance, witness McLeod highlighted that the Public Staff chose differing percentages for equitable sharing in each of the instances in which it has advocated for adoption of the principle—50/50 in the DEP rate case, 51/49 in the DEC rate case, and 60/40 in the instant case. *Id.* at 670. In witness McLeod's view, the Public Staff's "qualitative judgment" with respect to the proposed disallowance is inappropriate as a regulatory cost recovery approach.

Witness McLeod next refuted witness Maness' contention that the Commission should treat the Company's request to recover its prudently incurred CCR costs the same as it did costs associated with abandoned nuclear plants. In particular, witness McLeod noted that abandoned nuclear plant costs are not comparable to the costs of CCR remediation and closure of waste management facilities because—unlike CCR generating plants—abandoned nuclear plant costs were never used and useful in providing utility service to customers. *Id.* at 672.

Moreover, witness McLeod noted that the Commission rejected this comparison in the recent DEP and DEC rate cases.

Witness McLeod likewise disagreed with witness Maness' contention that the Commission's prior treatment of environmental clean-up costs of manufactured gas plants (MGPs) supports an equitable sharing of coal ash costs. In particular, witness McLeod noted a few key differences between MGP and coal ash costs. First, at the time of clean-up, the majority of MGP sites had not been used in decades. In contrast, the Company's coal-fired generating units and/or the coal ash disposal facilities are either still providing services to customers or were providing service until very recently. *Id.* at 674-75. Second, the coal-fired generating plants that utilized the coal ash disposal facilities have always been in the ownership of the Company or its predecessors. Most MGP sites, on the other hand, had several owners before being acquired by the regulated gas utilities that eventually undertook MGP clean-up. *Id.* at 675.

Rather than rely on the ill-fitting analogies put forth by witness Maness, witness McLeod urged the Commission to adopt the cost recovery methodology used by this Commission in the 2016 DENC Rate Case in Docket No. E-22, Sub 532 and the DEP and DEC rate cases that were heard in 2018 in Docket Nos. E-2, Sub 1142 and E-2, Sub 1146, respectively. *Id.* at 676. In each of those cases, witness McLeod noted, the Commission found the relevant CCR expenditures to be used and useful because they were included in the working capital section of the rate base and were investor-furnished rather than ratepayer-furnished funds. *Id.* at 679.

In addition witness McLeod stated that he did not believe the eighteen-year amortization period proposed by the Public Staff would be in the best interests of either North Carolina customers or the Company. He noted that a longer amortization period costs customers more in the long run and delayed recovery of these deferred costs puts more pressure on rates in the future as the company will continue to incur significant additional environmental expenditures related to CCR regulatory compliance in the coming years.

Finally, witness McLeod noted that witness Maness' proposal to account for CCR costs differently because they are an "extremely large cost" is not workable from a regulatory accounting perspective. Because the Public Staff and witness Maness have offered no explanation as to the definition of an "extremely large cost," adopting a regulatory order based on a subjective interpretation of the term is inconsistent with witness McLeod's experience of regulatory ratemaking and with known principles of regulatory accounting. *Id.* at 683. In this case the total rate changes in the stipulation provides for an overall rate decrease for the North Carolina jurisdiction. This includes amortization of the CCR regulatory over a five-year period with a return on the unamortized balance. According to witness McLeod, if the Public Staff's nineteen-year amortization proposal is adopted by the Commission the result will likely be overlapping vintages of CCR regulatory asset amortizations across multiple, future rate cases in which the Company will be requesting recovery of additional deferred CCR costs. The Company's proposed five-year amortization of these regulatory assets allows rates to be set at a just and reasonable level that positions the Company's current rate structure to recover these actually-incurred costs over a reasonable amount of time. *Id.* at 680-81.

DENC's Post-hearing Brief and Proposed CCR Order

DENC cited the Harris Order as the Commission's seminal standard of reasonable and prudent costs and stated that challenging prudence requires a detailed and fact intensive analysis, in which the challenger is required to: (1) identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives; and (3) quantify the effects by calculating imprudently incurred costs.

Further, DENC cited N.C.G.S. § 62-133(b)(1), and stated that the Commission must "[a]scertain the reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public within the State, less that portion of the cost which has been consumed by previous use recovered by depreciation expense." In addition, DENC noted that in applying the reasonable and prudent and used and useful standards, the Commission must apply the appropriate burden of proof to the Company's and intervenors' arguments. DENC argued that it incurred the CCR compliance costs at issue, supported by its application and the direct testimony filed in this case, and, therefore, it has met its prima facie burden. Moreover, DENC contended that its evidence was unrebutted because the Public Staff failed to identify or justify discrete disallowances under the applicable imprudence standard. As a result, DENC asserted that it is entitled to recover its CCR costs.

DENC maintained that the theory of "culpability" relied upon by the Public Staff is incompatible with the reasonable and prudent standard because Public Staff witness Lucas could not identify any specific CCR actions or costs that DENC should or could have taken prior to 2016. According to DENC, CCR impoundment closure, even under the supervision of state regulatory agencies, is a site-specific undertaking with procedures that have evolved over time and continue to do so, and in the absence of federal regulatory standards and guidelines to follow, no one can say what the prudent course would have been, even if one acts on the assumption that DENC was imprudent to await promulgation of the federal environmental regulatory requirements.

The Company asserted that it followed the prevalent and cost-effective approach, which was to install monitoring wells iteratively and methodically to best identify harmful groundwater contamination, and that it provided substantial, competent evidence that its historical CCR management practices have been reasonable and prudent. DENC submitted that absent any credible evidence that DENC's design, operation, or construction of its surface impoundments fell below applicable industry or regulatory standards, the Commission should conclude that the Company's historical CCR practices were reasonable and prudent.

Further, DENC contended that it appropriately responded to advances in industry practices for managing CCRs and cited numerous EPA and other reports that it maintained support its position. Moreover, the Company asserted that without an environmental justification to upgrade or retrofit its surface impoundments with liners, leachate collection or other remedial measures, taking such actions would not have been prudent or economically justifiable.

DENC further contended that absent specific findings of imprudence the Public Staff's recommended equitable sharing disallowance is not justified. The Company noted that the Commission did not accept the Public Staff's equitable sharing concept in the 2018 DEP and DEC

Rate Cases and contended it should likewise refuse to do so here. In particular, DENC stated that the equitable sharing approach is without standards, and, therefore, would be arbitrary for purposes of disallowing identifiable costs.

With regard to the amortization period over which the CCR costs should be recovered, DENC submitted that an amortization period of five years would be reasonable and appropriate. The Company stated that the Public Staff's proposed amortization period of eighteen years, with no return, would be arbitrary and unfairly punitive to DENC. Further, DENC asserted that because it appropriately applied ARO accounting, the Company is eligible to earn a return on the amortized CCR costs.

In summary, DENC requested that the Commission find by the greater weight of the evidence that the Company's CCR closure expenses incurred over the period from July 1, 2016, through June 30, 2019, are (a) known and measurable, (b) reasonable and prudent, and (c) used and useful, and are, therefore, recoverable in rates.

Public Staff's Proposed CCR Order

The Public Staff stated that one argument underpinning its equitable sharing recommendation is that the Company knew or should have known in past decades that its unlined coal ash impoundments had the potential to contaminate groundwater and surface water. The Public Staff pointed to the testimony of witness Lucas in which he identified a series of historical documents that showed a growing industry awareness of the risks of unlined surface impoundments, as well as a trend toward risk assessment and mitigation, and stated that based on these developments there was by 1979 a known risk of groundwater contamination from ash stored in unlined surface impoundments. In addition, Public Staff maintained that no evidence presented by the Company provided additional context that would contradict the assertion that the Company knew or should have known of the risks of its coal ash storage practices by the early 1980s.

The Public Staff further contended that in addition to the historical documents there were specific instances of actual environmental contamination that illustrated the risks of storing coal ash in unlined impoundments. As examples the Public Staff noted that the groundwater monitoring wells installed at the Possum Point facility in 1985 pursuant to the facility's NPDES permit detected violations of groundwater standards in the vicinity of Pond D and Pond E, resulting in a Special Order requiring further assessment of contamination and an evaluation of remediation options.

In addition, the Public Staff cited the Chisman Creek CERCLA site, at which coal ash generated at the Company's Yorktown facility had been disposed of in abandoned sand and gravel borrow pits between 1957 and 1974, causing groundwater, surface water, and soil contamination. The Public Staff contended that the Company should have known — given this actual evidence of environmental contamination both at its Possum Point facility and stemming from coal ash generated at its Yorktown facility and disposed of in unlined pits off-site — of the risks of contamination posed by unlined coal ash impoundments, and that DENC's actual experience at those locations provided knowledge of risk in the 1980s, in addition to the knowledge in the historical documents.

In addition, the Public Staff noted that it was unable to obtain information from the Company that would allow it to form a complete picture of the Company's past coal ash management. For example, the Public Staff cited witness Lucas' testimony that the Company was unable to provide groundwater monitoring reports for any of its facilities prior to the year 1999, as well as for select years after 1999, and that the Company could not locate a number of its past NPDES permits. The Public Staff also cited the records stipulation entered into by DENC and the Public Staff, and contended that the Company's inability to locate and provide historical documents and records concerning its past coal ash management practices is compounded by the fact that its primary witness on the matter of coal ash, witness Williams, only recently joined the Company in 2015, and, thus, does not have any first-hand knowledge of the Company's actual history of management of CCRs in prior years. Witness Williams' contention that he supplemented his knowledge by review of historical documents and records is difficult to square, the Public Staff contends, with the Company's inability to produce any significant quantity or quality of historical records.

Moreover, the Public Staff submitted that the weight of the evidence shows that the Company is culpable for groundwater contamination at its sites. The Public Staff stated that witness Lucas presented evidence that the Company had 548 exceedances of groundwater quality standards at its coal ash storage disposal sites, and contended that these groundwater exceedances show statistically significant exceedances over natural background levels, MCLs, and/or groundwater protection standards that are attributable to the migration of contaminants from the Company's coal ash disposal sites. In addition, the Public Staff maintained that the Company's failure in the 1980s to install comprehensive groundwater monitoring at its coal ash storage sites, and to use the data that could have been obtained from comprehensive monitoring to manage the risk of contamination, establishes DENC's culpability.

Further, the Public Staff urged the Commission to reject the Company's argument that complying with the directives of state environmental regulators is sufficient evidence that its coal ash management was reasonable and prudent, and to hold the Company to a standard based on whether a coal ash unit has the potential to contaminate the environment. The Public Staff maintained that the Commission should conclude that the Public Staff has presented sufficient evidence to show that environmental contamination from CCRs exists at all of the Company's coal ash disposal sites, and that the Company's coal ash impoundments pose a risk of future contamination that has required costly clean-up and closure to date and will require the further closure and excavation of ponds as mandated by the Virginia General Assembly.

According to the Public Staff, the Company bears culpability for not complying with state environmental regulatory policy to avoid degradation of groundwater. With respect to the role of the Public Staff and Commission, the Public Staff asserted that the Commission should find that witness Lucas has sufficient qualifications to provide competent testimony regarding the

Company's environmental compliance history, and that the Public Staff has broad authority under the Act to investigate the Company's cost recovery requests in a general rate case.[1]

In addition, the Public Staff contended that the Commission has the authority and discretion to order an equitable sharing of coal ash costs based on findings that the Company did not comply with environmental regulations, that DENC contaminated groundwater, that DENC created a risk of future contamination that affects remediation costs, and that the magnitude and nature of CCR costs justify a sharing between ratepayers and shareholders. In this regard, the Public Staff cited N.C.G.S. § 62-133(d), as providing the Commission with discretion to order equitable sharing on the basis that "other material facts of record" justify an adjustment necessary to achieve "reasonable and just rates." The Public Staff contended that a rate-oriented equitable sharing decision under N.C.G.S. § 62-133(d) does not require the identification of particular or specific costs resulting from an imprudent decision or act of the utility, or necessarily preclude an after-the-fact or hindsight review, such as environmental contamination results.

Finally, the Public Staff asserted that the Stipulation entered into in DENC's 2016 Rate Case does not estop the Public Staff or Commission from fully examining the prudence and reasonableness of DENC's CCR costs.

AGO's Post-hearing Brief

The AGO contended that if DENC is allowed to recover its CCR costs it should not be allowed to add a rate of return to those costs. The AGO stated that only a utility's rate base, not its operating expenses, is eligible to earn a return, and that DENC failed to show that its CCR costs meet the test for inclusion in rate base because it has not shown that the costs are for property that is used and useful for providing current service to consumers. The AGO cited and discussed several North Carolina Supreme Court cases on the issues of rate base inclusion and property used and useful, including *State ex rel. Utils. Comm'n v. Pub. Staff-N.C. Utils. Comm'n*, 333 N.C. 195, 202, 424 S.E.2d 133, 137 (1993) (*Carolina Trace*) (reversing Commission's order that put into rate base a wastewater connection that a utility was no longer using); *State ex rel. Utilities Com. v. Thornburg*, 325 N.C. 484, 495, 385 S.E.2d 463, 469 (1989) (*Thornburg II*) (reversing Commission's decision to put costs to construct excess nuclear facilities into rate base); and *State ex rel. Utilities Comm'n v. Carolina Water*, 335 N.C. 493, 507-08, 439 S.E.2d 127, 135 (1994) (*Carolina Water*) (reversing Commission's decision to put retired wastewater treatment plant into rate base).

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[1] Section 62-15(d) of the North Carolina General Statutes provides:

It shall be the duty and responsibility of the public staff to:

(1) Review, investigate, and make appropriate recommendations to the Commission with respect to the reasonableness of rates charged or proposed to be charged by any public utility and with respect to the consistency of such rates with the public policy of assuring an energy supply adequate to protect the public health and safety and to promote the general welfare;

(2) Review, investigate, and make appropriate recommendations to the Commission with respect to the service furnished, or proposed to be furnished by any public utility . . . .

The AGO maintained that DENC's CCR costs mainly involve expenditures made in preparing closure plans for CCR impoundments, treating contaminated groundwater, excavating coal ash, transporting it to other locations, and disposing of it, and that such costs are typically accounted for as operating expenses. Further, the AGO stated that the evidence indicates that the CCR costs were related to disposal of waste from power generation for electrical service that was provided in the past, instead of for property that is used and useful for providing electric service to current and future customers.

In addition, the AGO asserted that the costs to address coal ash do not become investment in rate base simply because the expenditures are useful for environmental compliance, and that environmental compliance costs can be reasonable and prudent, and thus recoverable as costs, and still fail the higher standard of being used and useful for providing current electric service, and thereby being allowed to earn a return.

Further, the AGO contended that the creation or existence of an ARO does not require that DENC's CCR costs be property used and useful, or to be used and useful within a reasonable time after the test period, in providing service rendered to the public, and that no exception to the used and useful requirement is provided for an ARO in the Act.

Finally, the AGO discussed several cases and asserted that our Supreme Court has not recognized any exception to the used and useful requirement based on funds being identified as working capital or as having been supplied by investors.

Discussion

Applicable Legal Principles

The Commission is required to set just and reasonable rates for public utilities. N.C.G.S. § 62-130(a). Just and reasonable rates are those that provide the utility an opportunity to earn a fair return on its property and are fair to the utility's customers. *State ex rel. Utilities Comm'n. v. Piedmont Natural Gas Co.*, 254 N.C. 536, 119 S.E.2d 469 (1961); *State ex rel. Utilities Comm'n. v. Duke Power Co.*, 285 N.C. 377, 206 S.E.2d 269 (1974).

The ratemaking process for the Commission to follow when deciding a general rate case is set forth in N.C.G.S. § 62-133. The statute makes clear that, in establishing rates for any public utility, the Commission "shall fix such rates as shall be fair both to the public utilities and to the consumer." N.C.G.S. § 62-133(a). Additionally, the statute requires the Commission to determine the utility's rate base. N.C.G.S. § 62-133(b). Finally, the statute provides that the Commission "shall consider all other material facts of record that will enable it to determine what are reasonable and just rates." N.C.G.S. § 62-133(d). As the North Carolina Supreme Court has noted, all sections of N.C.G.S. § 62-133 must be given weight in construing the language of any individual section of the statute. *Utilities Comm'n v. Duke Power Co.*, 305 N.C. 1, 18, 287 S.E.2d 786, 796 (1982).

To achieve just and reasonable rates, the utility's revenue must be sufficient to cover the utility's cost of service, plus allow the utility the opportunity to earn reasonable return on its rate base but must be fair to customers. To this end, the North Carolina Supreme Court has counselled:

> In sum, the fixing of "reasonable and just" rates involves a balancing of shareholder and consumer interests. The Commission must therefore set rates which will protect both the right of the public utility to earn a fair rate of return for its shareholders and ensure its financial integrity, while also protecting the right of the utility's intrastate customers to pay a retail rate which reasonably and fairly reflects the cost of service rendered on their behalf.

State ex rel. Utils. Comm'n. v. Nantahala Power & Light Co., 313 N.C. 614, 691, 332 S.E.2d 397, 474 (1985), *rev'd on other grounds*, 476 U.S. 953, 106 S. Ct. 2349, 90 L.Ed.2d 943 (1986), *appeal after remand*, 324 N.C. 478, 380 S.E.2d 112 (1989) (*Nantahala*).

When setting just and reasonable rates, the Commission must determine whether costs incurred by the utility were prudently incurred, which involves an examination of whether the utility's actions, inactions or decisions to incur costs were reasonable based on what it knew or should have known at the time the actions, inactions, or decision to incur costs were made. Harris Order at 14. Challenging prudence requires a detailed and fact intensive analysis, and the challenger is required to (1) identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives; and (3) quantify the effects by calculating imprudently incurred costs. Harris Order at 14-15.

Further, the "matching principle" dictates that customers who use an asset should pay for the asset at the time it is used. Put another way, the costs generated from a resource should be borne by the generation of customers that benefitted from the consumption of the resource. Thus, in striking the balance between shareholder and consumer interests, the Commission endeavors to avoid or minimize the extent to which present and future customers pay for costs incurred related to service provided in the past.

The burden of proof to show that rates are just and reasonable is on the utility. N.C.G.S. § 62-134(c). Nevertheless, intervenors have a burden of production in the event that they dispute an aspect of the utility's prima facie case. *State ex rel. Utils. Comm'n v. Intervenar Residents of Bent Creek/Mt. Carmel Subdivisions*, 305 N.C. 62, 76, 286 S.E.2d 770, 779 (1982) (*Intervenor Residents*) ("The burden of going forward with evidence of reasonableness and justness arises only when the Commission requires it or affirmative evidence is offered by a party to the proceeding that challenges the reasonableness of expenses . . . ."). If the intervenor meets its burden of production through the presentation of competent, material evidence, then the ultimate burden of persuasion reverts to the utility, in accordance with N.C.G.S. § 62-134(c).

As relates to the Commission's Order in DENC's 2016 Rate Case, the Company asserts that "[f]undamental principles of fairness and due process dictate that the Company should be able to rely on the Public Staff's prior position" regarding the ability of the Company to fully recover its coal ash expenditures. Tr. vol. 7, 58-59. In essence, the Company argued that the Public Staff is estopped from making a recommendation for the disallowance of costs based on the Company's

CCR management practices and environmental non-compliance because the Public Staff did not raise those concerns in decades past. *Id.* The Commission declines to accept this argument. The Company's obligation to serve the public interest and comply with applicable laws applies irrespective of whether or when the Public Staff or any governmental oversight or regulatory body challenges its actions.

In addition, the Commission agrees with the Public Staff that the order in DENC's 2016 Rate Case does not have precedential value with respect to the CCR issues in this case. Section VIII.D of the 2016 Stipulation between DENC and the Public Staff stated:

> Overall prudence of CCR Plan – The Public Staff's agreement in this proceeding to the deferral and amortization of CCR expenditures incurred through June 30, 2016, shall not be construed as a recommendation that the Commission reach any conclusions regarding the prudence and reasonableness of the Company's overall CCR plan, or regarding any specific expenditures other than the ones to be recovered in this case.

Agreement and Stipulation of Settlement at 10-11.

Likewise, the Commission's order in DENC's 2016 Rate Case expressly stated that the order should not be construed as a decision on the prudence and reasonableness of any CCR issues other than the CCR costs allowed in the 2016 proceeding:

> [F]urther, the Commission's determination in this case shall not be construed as determining the prudence and reasonableness of the Company's overall CCR plan, or the prudence and reasonableness of any specific CCR expenditures other than the ones deferred and authorized to be recovered in this case.

2016 DENC Rate Case Order at 63.

The evidence presented in DENC's 2016 Rate Case on the industry's and DENC's historical CCR practices and decisions was far less extensive than the evidence presented in the present case, mainly because the Company and Public Staff settled for the Company's recovery of its CCR remediation expenditures through June 30, 2016. As a result, the issues of prudence and reasonableness were not fully litigated and no significant evidentiary record was developed. Therefore, the Commission finds that it would be inappropriate to give the 2016 DENC Rate Case Order precedential effect for the treatment of costs the Company is seeking to recover in this proceeding.

Finally, the Commission's orders must be based on competent, material and substantial evidence in the record of the instant proceeding. N.C.G.S. § 62-65(a)

Reasonableness and Prudence of CCR Costs

As a general rule, when the utility presents evidence that costs were reasonably and prudently incurred and no additional evidence of prudence and reasonableness is presented, a prima facie case is made that the costs were reasonably and prudently incurred. *Intervenor Residents*, 305 N.C. at 76-77, 286 S.E.2d at 779. In direct testimony, DENC witness Mitchell stated that the enactment of the final CCR Rule in April of 2015 created a legal obligation for the Company to close all of its inactive and existing ash ponds, and to engage in monitoring and corrective action as necessary. Virginia incorporated the CCR legislation in Virginia enacted on March 20, 2019, requires the Company to move ash to lined landfills and to recycle 6.8 million cubic yards of ash from at least two sites. Tr. vol. 4, p 176. DENC witness McLeod stated that the Company's proposed revenue requirement in this case includes recovery of expenditures made between July 1, 2016, and June 30, 2019 (Deferral Period) to continue compliance with state and federal regulations related to CCR at several DENC facilities. *Id.* at 251. In general, DENC witnesses McLeod and Williams testified that the CCR expenditures were prudently made and therefore should be recovered in rates.

Witness Williams was DENC's sole witness on the substance of the Company's management and storage of CCRs. Witness Williams is a geologist with extensive experience in advising companies on environmental compliance matters and was employed for five years with Virginia DEQ as the lead person on reviewing CCR regulations. Witness Williams testified that his knowledge of DENC's CCR disposal practices was derived from reading hundreds of internal documents and talking to many DENC employees. He concluded that DENC had been prudent and reasonable in its decisions and actions in handling and storing CCRs. The Commission is unable to assess the breadth or depth of witness Williams' claimed review of internal documents, since few CCR documents were offered into evidence and there was substantial dispute between the Company and Public Staff concerning the completeness of the Company's internal records concerning past CCR policy decisions and management practices. What follows is the Commission's assessment of the limited documentary record that was provided.

In the 1981 EPRI manual entitled *EPRI Coal Ash Disposal Manual* (2d ed. 1981), DEC Rate Case, Docket No. E-7, Sub 1146, Sierra Club Kerin Cross-Exam Exh. 4, at 3-1,[1] EPRI stated: "While most coal ash is currently handled in wet systems, the national trend is away from wet disposal systems toward dry handling methods." Indeed, DENC was a part of that national trend in 1985 when the Company converted to a lined dry ash landfill at Chesapeake and built a lined dry ash landfill at Yorktown, and in 1995 when the Clover plant was constructed using only dry ash handling with the ash disposed of in a lined landfill. As a result, wet sluicing of ash to unlined ponds was mostly discontinued other than at the Company's oldest plants, those constructed before the 1980s – principally Bremo, Possum Point, and Chesterfield. Further, in the 1960s, far ahead of its time, DENC built Pond D at Possum Point with a clay liner. Similarly, in the mid-1980s when DENC built a new Pond D at Possum Point, it also included a clay liner. The Commission gives significant weight to these demonstrations of the Company's forward thinking and prudence in its CCR management practices. The Company's leadership in dry ash handling has resulted in the

[1] The documents identified as being introduced in the DEC Rate Case, Docket No. E-7, Sub 1146, were introduced in this proceeding by the Public Staff by incorporation into witness Lucas' prefiled direct testimony.

avoidance of millions of tons of wet storage CCRs that would have to be remediated today at substantially greater cost than will be required to permanently close its landfills. However, the Commission observes that DENC could not establish that it studied or performed any cost benefit analysis regarding converting its coal-fired plants from wet ash handling facilities to dry ash handling facilities once it converted two of its plants in 1985 or after it constructed a new coal-fired plant with dry ash handling facilities in 1995.

In addition, there is substantial evidence regarding DENC's compliance with legal requirements for handling and storing CCRs that tends to show that DENC was attentive to the applicable legal standards of the day, as well as evolving standards. Other than the Virginia DEQ Special Orders on Possum Point, there is no evidence of DENC having been the subject of notices of violation, NPDES permit revocations, other remediation orders, or enforcement actions by environmental regulators. As witness Williams testified, unlined impoundments were the accepted repositories for storing CCRs prior to adoption of the CCR Rule, and compliance with the Clean Water Act and NPDES permits for water discharges was generally accepted as meeting the expectations of environmental regulators. Although the Commission does not view regulatory compliance as being prudence *per se*, such compliance is nonetheless evidence that could support a determination of prudence.

Further, the evidence shows that DENC cooperated fully with Virginia DEQ in responding to the Possum Point Special Orders and ultimately reached a resolution of the groundwater concerns at that plant that was acceptable to Virginia DEQ. Moreover, the evidence establishes that DENC acted prudently and responsibly in response to the water degradation that occurred at Chisman Creek. As witness Williams testified, that site became a CERCLA remediation site because of actions and omissions of an independent contractor, not DENC. The site was not a CCR surface impoundment managed by DENC when the release of contaminants occurred. Yet when the contractor did not take financial responsibility for the Chisman Creek clean-up, DENC did so.

The Commission concludes, based on the foregoing evidence, that DENC made a prima facie case that the expenditures made between July 1, 2016 and June 30, 2019 to continue compliance with state and federal regulations at several of its CCR sites were prudently made.

Neither the Public Staff nor any other party to the proceeding expressed opinion on the prudence and reasonableness of the CCR Costs. Instead, Public Staff witness Lucas testified to a number of deficiencies in the Company's historical management of CCRs and the resulting environmental impacts. The following evidence was provided by Public Staff witness Lucas and the Public Staff's exhibits:

- Witness Lucas testified that the earliest monitoring of groundwater and leachate by DENC began in December 1983, and that the Company did not engage in comprehensive groundwater monitoring until later. *See* Lucas Exhibit 1. That exhibit shows that there were eight CCR ponds for which the first groundwater sampling date was 2000 or later, as follows: one pond in 2000, two ponds in 2013, one pond in 2015, three ponds in 2016, and one pond in 2018.

- Witness Lucas recounted in detail DENC's studies and consultants' recommendations, totaling at least seven reports, in response to a 1987 Special Order of the Virginia State Water Control Board (VWCB) requiring DENC to remediate groundwater violations at Possum Point Ponds D and E. The VWCB issued another Special Order in 1989. Witness Lucas stated that DENC's consultant recommended that DENC construct a dry waste disposal site at Possum Point, but DENC decided not to do so. He opined that this appears to be unreasonable.

- Witness Lucas stated that a consultant's report that included a compilation of 2003 groundwater data for Pond E at Possum Point showed 49 statistically significant exceedances of dissolved constituents of barium, cadmium, copper, iron, manganese, nickel, phenols, potassium, sodium, and zinc. The report further stated that the data "suggests that historical activities in the area of [Ash Ponds D and E] have degraded groundwater quality compared to background levels." Tr. vol. 6, 156.

- Witness Lucas' testified that he reviewed the Chisman Creek report, entitled *1990 Superfund Site Interim Closeout Report*, which stated that between 1957 and 1974 DENC hired a private contractor to haul fly ash from the Yorktown plant to four abandoned sand and gravel pits on the Yorktown property. Witness Lucas stated that Records of Decision were signed by EPA in 1986 and 1988 and included objectives for remediation.

- Witness Lucas' Exhibit 13 showed that DENC's CCR ponds had a total of 490 CCR Rule groundwater monitoring exceedances in 2017 and 2018. Witness Lucas testified that these records show repeated evidence of degradation of groundwater quality resulting from DENC's CCR disposal practices. Witness Lucas testified that a lack of documentation for many plants prior to 2000 leaves unanswered questions about what DENC knew when it made key decisions about CCR disposal.

In addition to the evidence presented by the Public Staff, a number of facts provided by witness Williams and the Company's documents highlight the risks taken by the Company with respect to its historical management of its CCR liabilities and call into question DENC's prudence, as follows:

- Prior to the effective date of the CCR Rule, DENC considered unlined ponds to be a permanent CCR disposal solution.

- Prior to the effective date of the CCR Rule, DENC's plan was to close all ponds in place.

- Closure in place was accomplished by partially covering the pond with soil, in a few instances, and allowing grass and other vegetation to reseed and spread over the surface naturally. No water was removed and no complete or engineered cap or cover was placed over the ponds. Because the impoundments were not dewatered when their use ceased, hydraulic pressure in the impoundments continued to facilitate the migration of ash constituents into the groundwater.

- There were no written closure plans detailing the steps to be taken when use of the impoundments to receive and temporarily store sluiced ash stopped, except the 2003 plan for Chesterfield.

- There were no written analyses, cost-benefit analyses, or reports on alternative storage options, other than the 1984 study for Chesapeake, and several studies in the 1980s for Possum Point.

As well, the following industry and government studies of which the Commission took judicial notice, taken separately and together provide evidence of industry best practices related to the management and disposal of CCRs.

1981

EPRI Coal Ash Disposal Manual (2d ed. 1981), DEC Rate Case, Docket No. E-7, Sub 1146, Sierra Club Kerin Cross-Exam Exh. 4, at 3-1 – "While most coal ash is currently handled in wet systems, the national trend is away from wet disposal systems toward dry handling methods."

1982

EPRI Manual for Upgrading Existing Disposal Facilities (Aug. 1982), DEC Rate Case, Docket No. E-7, Sub 1146, Sierra Club Kerin Cross-Exam Exh. 2 – Paragraph entitled "Effects on Groundwater" noted that "In general, inadequately lined ponds provide a greater opportunity for groundwater contamination, because the soil immediately below the pond is always saturated and under a constant head of pressure from the overlying water. Consequently, seepage may be constant and greater in volume than leachate from a landfill." *Id.* at 2-11 (footnote omitted).

Paragraph entitled "Identifying Design and Operational Deficiencies" noted that there are two possible standards, one being specific federal and state regulations, and the other being "[t]he site has the potential to contaminate the environment." The text goes on to state:

> [I]dentification and correction of regulatory deficiencies do not necessarily preclude the possibility of past or future environmental degradation by the site. Conversely, known degradation cannot be corrected by simply conforming to the regulations. State and federal waste disposal regulations are directed at those designing a new site or closing an old site, not for those wishing to upgrade and continue operating a substandard site.

Id. at 4-1 to 4-2.

1985

Full-Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants (Little Report, 1985), DEC Rate Case, Docket No. E-7, Sub 1146, Public Staff Wells Cross-Exam Exh. 6 – EPA funded report conducted by Arthur D. Little, Inc., involving a study of six coal-fired plants, one of which was DEC's Allen plant. The section entitled "Results and Conclusions for the Six Study Sites" included these two statements

> (2) Releases of most trace metals are generally within acceptable limits (e.g., drinking water and aquatic life standards) because of the combined effects of receiving water dilution and the chemical immobilization of most water-related species. Arsenic is a significant exception that would require case-by-case evaluation for analogous wastes. In this study, elevated concentrations of arsenic in the in-situ liquid phase and/or off-site mobility of arsenic were observed at three of the six sites.
>
> (3) In settings characterized by at least modest precipitation and fairly pervious soils where disposal occurs in direct hydrogeologic proximity to a subsurface drinking water supply or small, high-quality surface water body, an artificial disposal site liner may be needed to minimize contamination by (at least) the major species. A minimum liner thickness of about 0.5 m (1.5 ft) would suffice for proper engineering placement of soil-like liners.

Id. at 5-1.

1988

EPA Report to Congress entitled *Wastes from the Combustion of Coal by Electric Utility Power Plants*. On page 4-54, it notes that "More than 40 percent of all generating units constructed since 1975 use lined disposal facilities."

2004

EPRI Decommissioning Handbook for Coal-Fired Power Plants (Nov. 2004), DEC Rate Case, Docket No. E-7, Sub 1146, AGO McManeus Cross Exam Exh. 2; Tr. vol. 10, 695-782. The manual highlighted the need for utilities to give attention to the process and cost of permanently storing CCRs.

> There are serious issues in plant site decommissioning, most of them environmental. The disposal of many years of waste products – ash, water, oils, chemicals – and the removal of asbestos, PCBs, lead products, etc., requires both an understanding of the extent of the contaminations as well as the best methods of removing and disposing of the substances.
>
> . . .
>
> Closure of surface impoundments and landfills probably will be the most expensive tasks undertaken during a decommissioning project.
>
> . . .

> Closure of most surface impoundments will require drainage, placement of an impermeable cap, and topping with soil and a vegetative cover. . . . The caps for the impoundments will require continued maintenance to maintain the site contours, vegetative cover and drainage. Some impoundments will require the installation and monitoring of groundwater wells. The waste in other surface impoundments may be excavated for disposal offsite, and the impoundment backfilled with clean material.

Tr. vol. 10, 704, 722, 724.

The EPRI handbook described three case studies on plant decommissioning, including the estimated or actual costs incurred. One of the studies was Georgia Power Company's Arkwright Plant. The Arkwright plant was retired in 2002, and the final site cleanup was expected to be completed in 2006. The study reported that the costs for closure of CCR surface impoundments at the Arkwright plant were estimated to be $10,700,000, or about 56.3% of total decommissioning costs net of salvage recovery. *Id.* at 753. Another of the studies was the TVA's Watts Barr plant, which was retired in 2000. The cost for closure and remediation of dry ash units and surface impoundments was estimated to be $9 million, with the total decommissioning cost estimated at $17 million to $25 million. *Id.* at. 754. Notably, the 2004 EPRI Decommissioning Manual preceded the adoption of the CCR Rule by a decade. It is evidence of industry understanding and best practices at a time well before regulatory requirements were in place. The Commission notes that this Manual was issued roughly contemporaneously with the Company's abandonment of the surface impoundments at Possum Point in 2003 when the plant was converted from coal to natural gas. The Company took none of the actions recommended and discussed in the Manual when it ceased use of the Possum Point impoundments.

Challenging prudence requires a detailed and fact-intensive analysis. Imprudence is established by evidence: (1) identifying specific and discrete instances of imprudence; (2) demonstrating the existence of prudent alternatives; and (3) quantifying the effects by calculating imprudently incurred costs. Harris Order, at 15. In the instant proceeding, while the evidence demonstrates a difference of opinion or dispute as to whether certain Company actions, omissions or decisions were prudent, there is no dispute among the parties as to whether any CCR Costs were imprudently incurred.

More specifically, no party presented evidence to attempt to quantify which, if any, of the CCR Costs might have been avoided if DENC had used a different approach to managing its CCRs at some point during the last several decades. Indeed, it would be very difficult to go back and recreate the timing and cost of such different approaches. For example, one could argue that DENC should have converted all of its coal-fired plants to dry ash handling at least at some time during the 1990s. However, to quantify the costs and benefits of this strategy would require establishing, with some level of certainty, the costs that DENC would have incurred for such conversions, and the savings in present CCR remediation costs that would have resulted from such conversions. In addition, DENC could have been entitled to recover those conversion costs, plus a return on its increased rate base, from its ratepayers over the past several decades. On the present record, the Commission has no substantial evidence on which to make such determinations.

Thus, based on the foregoing, the Commission concludes that none of the CCR Costs incurred by the Company between July 1, 2016 through June 30, 2019 shall be disallowed on the basis of having been imprudently incurred. Put another way, based on the evidence in the record in the instant proceeding, the Commission concludes that the CCR Costs were prudently incurred.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 53-55

The evidence in support of these findings of fact and conclusions is found in the testimony of DENC witnesses Williams and McLeod, and Public Staff witnesses Lucas and Maness.

Return on the Unamortized Balance

With respect to whether DENC should be allowed to earn a return on the unamortized balance of the CCR costs during the amortization period, DENC takes the position that the Company is entitled to a full recovery of its CCR Costs, in addition to a return on the unamortized balance while the costs are being amortized. The Public Staff's equitable sharing is achieved, in part, by not allowing a return on the unamortized balance while the costs are being amortized. The AGO takes the position that the Company is not entitled to a return as the costs do not constitute property used and useful in providing utility service.

In analyzing whether DENC should be allowed to earn a return on the unamortized balance of the CCR costs during the amortization period, the Commission finds instructive the cases addressing environmental remediation costs associated with manufactured gas plant and cancellation costs associated with nuclear generating facilities. In Docket No. G-5, Sub 327, Public Service Company of North Carolina, Inc. (PSNC) sought recovery of costs incurred for remediating environmental impacts identified at manufactured natural gas plants (MGPs). Before piped natural gas became available in the 1950s, gas was commonly manufactured by a process that involved the heating of coal in a reduced-oxygen environment. The plants in question in this particular proceeding had been constructed from the mid-1800s to the early- 1900s. The MGPs were taken out of service in the 1950s. By-products of the gas manufacturing process included sulfur, hydrogen sulfide, iron cyanide, light oils, tar, water and coke. These by-products were disposed of consistent with the law applicable at the time but had become the subject of environmental law and regulation. The anticipated remediation costs were estimated to be substantial. The Commission concluded that it was appropriate to allow PSNC to recover its prudently incurred MCP environmental clean-up costs as reasonable operating expenses amortized over a period of years. The Commission did not allow PSNC to earn a return on unamortized balance. The Commission concluded

> that the proper balance between ratepayer and shareholder interests is achieved by amortizing the prudently incurred costs to O&M expenses in general rate cases but denying the Company any recover from ratepayers of the carrying costs on the deferred and the unamortized MGP clean-up cost balances.

MGP Order at 23. The Commission reasoned that its approach to ratemaking treatment (which also included rejecting the utility's proposed annual tracker mechanism) gave PSNC an incentive to minimize clean-up costs and to pursue contributions from third parties where appropriate.

Finally, looking ahead and anticipating extensive future clean-up costs for MGP liabilities, the Commission reasoned that an appropriate amortization period could be determined in each future rate case proceeding, depending on the magnitude of the costs incurred.

In Docket No. E-22, Sub 273, DENC's 1983 rate case, DENC sought recovery of the abandonment costs of North Anna Units 3 and 4 and Surry Units 3 and 4. The Commission found that DENC's decisions to cancel these nuclear units were reasonable and prudent and that DENC should be allowed to recover its costs up to the point of abandonment. Further, the Commission found that the loss was fairly allocated between DENC and its ratepayers through amortization and not allowing a return on the unamortized balance during the amortization period. The Commission reasoned that:

> [i]t would be inequitable to place the entire loss of expenditures that were prudent when made on the utility. Thus, amortization should be allowed. However, on the other hand, the ratepayer must not bear the entire risk of the Company's investment. A middle ground must be found on which the Company bears some of the risk of abandonment and the ratepayer is protected from unreasonably high rates.

Order Granting Partial Increase in Rates, *Application of Virginia Electric and Power Company for Authority to Adjust and Increase Its Electric Rates and* Charges, No. E-22, Sub 273, 73 N.C.U.C. Orders & Decisions 343, 355 (Dec. 5, 1983) (Anna/Surry Order).

Most recently, this same principle was applied by the Commission in denying DEC a return on the costs of its abandoned Lee nuclear plant. That order included a discussion of numerous similar decisions by the Commission during the last several decades. DEC Sub 1146 Order at 160-63.

As the foregoing decisions by the Commission demonstrate, there is a well-established history of allocating prudently incurred costs, specifically in the context of extraordinary, large costs such as environmental clean-up and plant cancellation, between ratepayers and shareholders in order to strike a fair and reasonable balance. The Commission concludes that in the present case, fairness dictates this same treatment.

DENC's CCR Costs were prudently incurred, thus, it would be inequitable to place the entirety of CCR Costs on DENC's shareholders. However, neither should ratepayers bear the entire risk, and the rate impact, associated with DENC's CCR liabilities.

A number of material facts in evidence call into question the prudence of DENC's actions and inaction and the risks accepted by DENC management at several of its CCR sites. For example, see the discussion of the Possum Point CCR site supra, and the pertinent portions of the industry and government documents previously discussed, such as the 1982 *EPRI Manual for Upgrading Existing Disposal Facilities* and the 1988 EPA Report to Congress entitled *Wastes from the Combustion of Coal by Electric Utility Power Plants*. Moreover, as was the case in the context of the MGP cases and the cancelled nuclear plant cases, the total costs incurred is significant (approximately $377 million on a system level approximately $22 million on a North Carolina retail level), which amounts to approximately $179 per North Carolina retail customer, or $60 per year per North Carolina retail customer, assuming the unamortized balance is not included in rate base. Additionally, allocating all of the CCR Costs to ratepayers violates the matching principle and raises intergenerational equity concerns. DENC's CCR Costs address many decades' worth of coal-ash waste and the closure of coal ash basins related to electric service provided to customers in the past. Tr. vol. 5, 85-88. In fact, most of DENC's expenditures relate to generating stations that have been retired or converted to natural gas and the ash ponds have been retired for years or decades. *Id.*; Late Filed Exhibit 5 MDM-1. Thus, DENC's present and future ratepayers are being burdened with costs arising from past service. Therefore, as it is so required by N.C.G.S. § 62-133(d), the Commission considers these material facts of record when striking the appropriate balance between shareholder and customer interests to set just and reasonable rates. *State ex rel. Utils. Comm'n. v. Thornburg*, 314 N.C. 509, 511, 334 S.E.2d 772, 773 (1985) (concluding that "[i]n setting rates, the Commission must consider not only those specific indicia of a utility's economic status set out in N.C.G.S. § 62-133(b) but also all other material facts of record, which may have a significant bearing on the determination in the case.").

A fair and reasonable balance is found which requires DENC's shareholders to bear some of the risk of clean-up costs associated with CCR liabilities and protects the ratepayers from unreasonably high rates. The Commission concludes that the Company shall not be entitled to earn a return on the unamortized balance of CCR Costs during the amortization period, in light of: (1) the Commission's obligation to set just and reasonable rates that are fair to both the utility and the ratepayer in accordance with N.C.G.S. § 62-133(a); (2) the Commission's historical treatment of extraordinary, large costs, such as MGP environmental remediation costs and plant cancellation costs; and (3) the Commission's obligation to consider all other material facts of record that will enable it to determine what are just and reasonable rates in accordance with N.C.G.S. § 62-133(d).

The Commission notes that the MGP Order points out that the MGP sites were not "used and useful" in providing gas service to current customers. The Commission made a similar determination in the Anna/Surry Order. In their post-hearing filings, DENC, the Public staff, and AGO have addressed in some detail the question of whether DENC's CCR remediation and waste facility closure work has resulted or will result in property used and useful for serving current and future ratepayers. However, as discussed below, based on the evidence in the record, the Commission need not decide in the instant proceeding whether DENC's CCR Costs at issue in this case have produced property that is or will be used and useful in providing service to present and future ratepayers.

With respect to whether the CCR Costs are entitled to a return under N.C.G.S. § 62-133(b)(1), DENC witness McLeod maintained that they are so entitled, in light of the Commission's decisions in the 2016 DENC Rate Case and the 2018 DEP and DEC rate cases that the CCR expenditures were "used and useful" because they were recorded by the utilities in the working capital section of the rate base and were investor-furnished rather than ratepayer-furnished funds. *Id.* at 679. The Commission is not persuaded by this position.

North Carolina General Statutes § 62-133(b)(1) allows the recovery of a return on investment in property and plant that is used and useful in providing utility service. The Commission takes no issue with the Company's decision to establish an ARO to recognize its CCR obligations or its labeling of CCR costs as working capital for accounting purposes. However, these accounting practices do not *ipso facto* transform these costs into expenditures for "property used and useful" under the Act. Further, the Supreme Court's holding on working capital made in *State ex rel. Utilities Commission v. Virginia Electric & Power Co.*, 285 N.C. 398, 206 S.E.2d 283 (1974) (*VEPCO*), did not change the used and useful requirement of N.C.G.S. § 62-133(b)(1). The Company advances a reading of *VEPCO* that would, if accepted, obliterate any distinction between investment in property used and useful in providing service to customers and expenditures for ordinary operation and maintenance. As the Company reads that case, all amounts expended by the Company for whatever purpose and to whatever end constitute "working capital" eligible to earn a return, unless perhaps those amounts are funded from prepayments made by customers. This argument ignores the important portion of the holding in *VEPCO* that affirmed the Commission's $60,783 deduction from working capital in recognition of the Company's rates that included an amount for payment of the Company's federal income taxes. The Company protested that this deduction was improper because the Company's tax deferral account showed a negative amount for federal income taxes during the test period. In upholding the Commission's position, the Court stated:

> The absence of an actual tax liability during the test period does not alter the fact that Vepco's North Carolina customers have paid to it rates which included enough to cover anticipated Federal income taxes. The question here is not how much, if anything, Vepco must pay to the United States. The questions are how large a fund Vepco has collected from its customers with which to pay taxes and how long it has had the use of such fund. Having had the use of funds so collected, it is not entitled to ignore its use thereof when computing its working capital requirement. We see no error in the order of the Commission in this respect.

VEPCO, at 416-17.

Also undermining DENC's position in the present case is the Company's own evidence showing its calculation of its requirement for "cash working capital." NCUC Form E-1, Item No. 14. None of the expenditures made to address coal ash are included in the Company's analysis of its working capital needs. As a result, the Company's contention that it has used shareholder provided working capital to pay for expenditures to comply with the CCR Rule and close its coal ash facilities is nothing more than an *ipse dixit* entitled to no evidentiary weight.[1]

Additionally, at the hearing witness McLeod confirmed that the vast majority of the CCR expenditures were for services and labor and would have been charged to operation and maintenance expenses in the absence of GAAP ARO accounting requirements. Tr. vol. 7, Official Exhibits, Public Staff McLeod Cross-Examination Exh. 1. He also confirmed that roughly 98% of the CCR costs incurred during the Deferral Period would have been booked as operation and maintenance expenses but for GAAP accounting requirements. Tr. vol. 7, 9-11; *see also* Tr. vol. 7,

[1] On this issue it is well to keep in mind Justice, later Chief Justice, Barnhill's observation in *State ex rel. Utilities Commission v. North Carolina*, 239 N.C. 333, 348, 80 S.E.2d 133, 143 (1954), that when "it is made to appear [the utility] has on hand continuously a large sum of money it is using as working capital and to pay current bills for materials and supplies, that is a fact which must be taken into consideration. And if the fund on hand is sufficient, no additional sum should be allowed at the expense of the public."

Official Exhibits, Public Staff Paul McLeod Cross-Examination Exh. 2. Further, he agreed that $209 million of the total $390.4 million total CCR expenditures were incurred at coal plants that had been decommissioned. Tr. vol. 7, Official Exhibits, Public Staff Paul McLeod Cross-Examination Exh. 2. Thus, it is very likely that had the CCR Costs been incurred during the test year, they would have been recovered as operating expenses on which no return would have been earned.

Giving weight to all sections of N.C.G.S. § 62-133 when construing the language of any individual section of the statute, as the North Carolina Supreme Court has indicated the Commission must do, the Commission determines that just and reasonable rates are achieved, based on the evidence in the record in this proceeding, only when the unamortized balance of CCR Costs are not allowed to earn a return. *Utilities Comm'n v. Duke Power Co.*, 305 N.C. 1, 18, 287 S.E.2d 786, 796 (1982). Accordingly, based on the record as a whole, the Commission concludes that it is appropriate to treat the CCR Costs as deferred operating expenses and not as costs of property used and useful within the meaning and scope of N.C.G.S. § 62-133(b) and to not allow a return on the unamortized balance of the CCR Costs.

Amortization Period

With regard to the amortization period over which the CCR costs should be recovered, DENC submitted that an amortization period of five years would be reasonable and appropriate. The Public Staff proposed an amortization period of eighteen years as part of its equitable sharing recommendation. The Commission has declined to adopt the Public Staff's equitable sharing recommendation. However, the Commission has determined that a reasonable balancing between shareholders and ratepayers of the costs of CCR remediation is just and reasonable and must establish an appropriate amortization period based on the evidence in the record in this proceeding. The Commission concludes that DENC's proposed five-year amortization period does not achieve a fair balance in light of the evidence in the record, the magnitude and the nature of the costs involved and the rate impact to customers. The Commission concludes that based on the evidence in the record, the magnitude and nature of the costs involved and the rate impact to customers as testified to by the Public Staff, a ten-year amortization period strikes the more appropriate and fairer balance. This decision is consistent with the Commission's historical treatment of major plant cancellations. *See* Anna/Surry Order at 355 (noting that [t]his Commission has consistently used a write-off period of 10 or fewer years for all major plant cancellations).

Financing Costs During Deferral Period

The Commission concludes that allowing the company to recover the financing costs incurred during the Deferral Period and up to the effective date of the new rates approved pursuant to this Order, calculated at the Company's previously authorized weighted average cost of capital, is reasonable based on the facts of record in this proceeding.

The decision to allow the Company to recover its financing costs incurred during the Deferral Period is made independently of the Commission's decision regarding the Company's right to earn a return on the unamortized balance of the CCR Costs during the amortization period. It is within the Commission's authority to approve a regulatory asset to defer for future recovery expenses that were incurred in the past and even to provide for a return on those deferred expenditures, such as by providing for carrying costs. In compliance with this Commission's authorization in the 2016 DENC Rate Case, the CCR Costs have been deferred to permit appropriate ratemaking treatment in this general rate case. The ratemaking treatment of the CCR Costs has been established in accordance with N.C.G.S. § 62-133 and applicable legal principles, as previously discussed in this Order. The Commission concludes that, separate and distinct from the ratemaking treatment afforded the CCR Costs, allowing the Company to recover its financing costs incurred during the Deferral Period is appropriate based on the record of the instant proceeding.

Specifically, the Public Staff did not oppose the Company's recovering the financing costs incurred during the Deferral Period. Further, the Commission observes that such a return may reduce the incentive for the Company to apply for rate increases more frequently to avoid regulatory lag. While recovering financing costs incurred during the Deferral Period does not help with the Company's short-term cash flow, it means the Company ultimately does not experience lost financing costs if it delays a new rate case.

Public Staff's Equitable Sharing Recommendation

The Public Staff proposed allocating the Company's CCR Costs between shareholders and customers based on the concept of "equitable sharing."[1] The Public Staff takes the position that conducting a thorough analysis of the reasonableness and prudence of all actions and expenditures over several decades would be difficult, if not impossible, given the passage of time, the speculative nature of estimating historic environmental remediation costs, and the Company's lack of historical records and documents related to CCR liabilities. Therefore, the Public Staff's proposed equitable sharing is based on a weighing of the equities, as opposed to application of the ratemaking framework prescribed by N.C.G.S § 62-133. After considering the equities, the Public Staff concluded that, inasmuch as it determined DENC was "culpable" or accountable for taking the actions that have led to the current CCR Costs, DENC's shareholders should bear more of the burden of the CCR Costs than the customers, who relied and depended on the Company's safe and appropriate handling of CCRs. However, the Public Staff determined that the customers should also share in the burden of CCR Costs, but to a lesser degree, because they have benefitted from the past decades of coal-fired generation and past least-cost coal ash disposal methods (such as CCR surface impoundments) in the form of the lower electric rates.

The Commission understands the Public Staff's position on the challenges, in the context of the Company's CCR-related expenditures, to performing a review of the reasonableness and prudence of those expenditures. Nevertheless, the Commission has declined to follow the Public Staff's equitable sharing recommendation, and has instead, as discussed hereinabove, reached its decision based on the evidence in the record and adherence to the ratemaking framework

[1] The historical decisions of the Commission dealing with ratemaking treatment of extraordinary and significant costs, such as plant cancellation costs and MGP environmental remediation costs, do not involve or reference an "equitable sharing" approach but rather involve the application of the rate-setting provisions of the Act to the facts of the case. Thus, the approach recommended by the Public Staff in this proceeding, as well as the most recent DEC and DEP general rate cases, appears to be novel.

prescribed by N.C.G.S. § 62-133, which requires an analysis of the reasonableness and prudence of the expenditures in question. Because the record in this proceeding lacks an evidentiary basis on which to find that any of the CCR Costs were imprudent, the Commission declines to disallow the recovery of any of the CCR Costs, to the extent the Public Staff's approach could be interpreted to amount to a disallowance. In addition, contrary to the Public Staff's equitable sharing approach, in which the allocation of costs between customers and shareholders is predetermined (i.e., 60/40), based on a theory of "culpability" and the ratemaking treatment is then selected to achieve that predetermined allocation, the Commission has reached its determination on the recovery and ratemaking treatment of CCR Costs by applying the provisions of N.C.G.S. § 62-133, which involves an examination of reasonableness and prudence of the CCR Costs, to the evidence of record in this proceeding in a manner that is consistent with historical decisions of the Commission.

Compounding During Deferral Period

The Commission concludes the annual compounding approach recommended by the Public Staff and agreed to by DENC in its rebuttal testimony is more reasonable than monthly compounding for the return during the Deferral Period that it is reasonable, based on the evidence in the record in this proceeding, for DENC to recover its financing costs incurred during the Deferral Period. Further, the Commission concludes that the annual compounding approach recommended by the Public Staff and agreed to by DENC in its rebuttal testimony is more reasonable than monthly compounding for calculating financing costs during the Deferral Period. Annual compounding, as explained by Public Staff witness Maness, results in the Company recovering financing costs that correspond to the weighted average cost of capital approved in the Company's last general rate case, whereas monthly compounding would produce a higher amount of return.

Maintenance of Environmental Records

Finally, due to the Company's failure to retain or produce adequate records regarding its CCR handling and storage, the Commission finds good cause to require the Company to maintain complete records of all environmental management activity and test results as they pertain to its coal ash management program, and to make such records available to the Public Staff and the Commission upon request. Further, data collected by the Company in the course of its environmental regulatory compliance, including groundwater monitoring data and analytics as well as other environmental compliance data, should be provided to the Public Staff and the Commission in the format that is reasonably requested by the Public Staff and the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 56-58

The evidence supporting these findings of fact and conclusions is contained in DENC Late-Filed Exhibits 3 and 5, DENC's 2011 and 2016 depreciation studies, and the records of DENC's last three general rate cases, Docket Nos. E-22, Subs 459, 479, and 532.

As previously discussed, one of the fundamentals of cost-based ratemaking as it has developed in this state is that the full cost of providing utility service should be recovered, as near as may be possible, from rates in effect in the period in which service is provided. One objective of this useful and important "matching principle" is to encourage customers to make efficient and cost-effective use of utility services by enabling them to see and appreciate the full cost of the service provided, even when some of the expenditures required to provide the service may be incurred or made by the utility at some time either before or after the service is actually consumed. A companion objective is to avoid cost-shifting and subsidies among different generations of customers who consume service during different time periods. Achieving these objectives is complicated by the fact that many expenditures by a utility company, especially construction of capital intensive facilities to generate, transmit and distribute electricity, are lumpy; that is, a large expenditure may be made in a very short period of time, but the investment thus made will enable the utility to provide service to customers over many years. The well-accepted method for smoothing out this lumpiness and enabling the costs of large scale capital investments to be recovered from all generations of customers who will benefit from and receive service from those facilities is by allowing the utility to include in its rates a regular periodic allowance for use and consumption of the investment, i.e., an allowance for depreciation. Through depreciation allowance, recovery of the costs of making a large investment are spread over many ratepayers, rather than being borne only by that group of ratepayers taking service during the time the expenditure is actually made.

In the usual case costs associated with the retirement or decommissioning of a long-lived asset are, in accord with the matching principle, included as part of the periodic allowance for depreciation that is related to that asset. This marks a recognition of the fact that while significant costs are incurred to construct or to acquire an asset, it may also be that significant costs will be incurred when the asset reaches the end of its useful life, including such things as costs to dismantle, decommission, remove, secure, or dispose of the asset. Failure to anticipate these end-of-life costs and make provision for them in the periodic allowance for depreciation distorts the true cost of providing service to those customers who take service during the asset's useful life and shifts a portion of those costs to the unlucky customers who happen to take service at a time when the asset is retired. *Generally see, State ex rel. Utilities Commission v. Edmisten*, 291 N.C. 451, 232 S.E.2d 184 (1977) (*Edmisten III*). Such is the case here with respect to the costs of closing waste coal ash management units when they are no longer receiving ash. These end-of-life costs are referred to as either "interim" or "terminal" net salvage values and for purposes of depreciation they are treated the same as the initial cost to acquire or construct the asset. They may be positive, if the asset is expected to yield a positive return when it is retired, or they may be negative, if the cost of decommissioning the asset is expected to exceed any value from salvage.

In the present case, however, the Company's request to include in its present and future rates the costs of final handling and disposal of CCRs produced from the burning of coal over many decades is a departure from the matching principle. In response to a question from the Commission, the Company reported that it had not included in its allowances for depreciation any amount toward the costs now being incurred to close the waste ash management units at its coal-fired generating plants. DENC Late-Filed Exhibit No. 3. The Company stated:

> This is appropriate as the Company has not yet identified the nature and timing of such [closure] activities and therefore the projected costs have not been reasonably known and measurable. This treatment is assessed by the Company's accountants,

depreciation consultant and generation management as part of preparing each depreciation study.

It is clear from the Company's response and from the record of this case and the Company's prior rate cases that at no time prior to the present rate case – not as part of its depreciation studies prepared in 2011, or in 2016, and not as part of its general rate case applications filed in 2009, 2012 and 2016 – has the Company sought to recover in its rates any amount for costs of final closure of its waste ash management facilities. *See* Docket Nos. E-22, Subs 459 and 479 (updated 2011 depreciation study filed in Docket No. E-22, Sub 493 on April 1, 2013); and Sub 532 (updated 2016 depreciation study filed in Docket No. E-22, Sub 562 on August 21, 2019). The Company's explanation of its failure to consider or include costs of closure for waste coal ash facilities in calculating an allowance for depreciation is not persuasive for a number of reasons.

Industry understanding of the need to anticipate significant costs for final closure of waste coal ash management facilities is not something that developed only recently. On this topic Company witness Williams acknowledged that he was familiar with the 2004 report prepared by EPRI titled "Decommissioning Handbook for Coal-Fired Power Plants" (Decommissioning Manual). Tr. vol. 10, Official Exhibits, DEC Rate Case, Docket No. E-7, Sub 1146, AGO McManeus Cross-Exam Exh. 2, at 699-782. However, he dismissed the report as merely a series of case studies, ignoring the report's general findings and conclusions, including this clear and unambiguous admonition:

> [C]losure of most surface impoundments will require drainage, placement of an impermeable cap, and topping with soil and a vegetative cover. . . . The caps for the impoundments will require continued maintenance to maintain the site contours, vegetative cover and drainage. Some impoundments will require the installation and monitoring of groundwater wells. The waste in other surface impoundments may be excavated for disposal offsite, and the impoundment backfilled with clean material.

Id. at 724.

Discussing the various tasks and costs that could be expected as part of the retirement of a plant, the manual later observed that "[c]losure of surface impoundments and landfills probably will be the most expensive tasks undertaken during a decommissioning project." *Id.* at 722. Nothing in the 2004 EPRI Decommissioning Manual is presented as novel, unexpected, groundbreaking, or beyond the scope of sound industry practice as it was understood in 2004. It is notable that this report precedes by more than a decade the adoption of the CCR Rule and was issued several years before the EPA commenced rulemaking on the subject of disposal of coal ash wastes. The case studies presented in the report make clear that the costs of closure of coal ash disposal facilities could likely range well into the tens of millions of dollars.

We know now that the costs that DENC is likely to incur will greatly exceed even the amounts revealed in the 2004 case studies reviewed in the EPRI Decommissioning Manual, and the Company apparently believes that the difficulty in making precise estimates of final closure costs absolves it of responsibility for making the effort to do so at all. This is not acceptable. As the Company itself noted in its response to the Commission's question, depreciation studies and requested allowances for depreciation are periodically reviewed and updated to include the latest information and to make adjustments where necessary in light of such new information. This was precisely the purpose of the Company's regular review and updating of its depreciation studies in 2006, 2011 and 2016. Further, this is quite similar to the requirement for establishing an Asset Retirement Obligation (ARO) when the Company has a known but not perfectly quantifiable risk associated with future retirement of a long-life asset. *See* Order Allowing Utilization of Certain Accounts, *Request by Virginia Electric and Power Company, d/b/a Dominion North Carolina Power*, No. E-22, Sub 420 (N.C.U.C. Aug. 6, 2004) (approving DENC's use of ARO accounting for certain long-life assets in compliance with Statement of Financial Accounting Standards No. 143).

This is not a case where the Company simply made inaccurate projections of the necessary allowance for net salvage to be included in depreciation allowance; instead, with respect to that portion of net salvage value attributable to the costs of remediating and closing coal ash waste management facilities it failed to engage in the exercise at all.

Recovery of net salvage in depreciation, including costs of removal, decommissioning, and closure, has been endorsed by the Commission, and the Company cannot complain that there has been no regulatory guidance on the subject.

Pertinent here is the Commission's decision in Order Granting Partial Rate Increase, *Application by Aqua North Carolina, Inc., for Authority to Increase Rates for Water and Sewer Utility Service in All of Its Service Areas in North Carolina*, No. W-218, Sub 319 (N.C.U.C. Nov. 3, 2011) (Aqua Order). In that proceeding, Aqua and the Public Staff disagreed as to the propriety of including in depreciation expense, and thus in rates, amounts for terminal net salvage value that would reflect and incorporate costs of removal. The Company's witnesses pointed out that including these amounts in current depreciation expense would properly assign a portion of expected future expenses to those customers who were currently receiving the benefit of the utility plant while it was still in service. The Public Staff contended that such a practice would improperly require present customers to pay for future costs that might or might not actually be incurred or might be different in amount at the time actually incurred. As to this difference of opinion, the Commission noted the applicant's testimony in the following summary:

> Witness Spanos advocated utilizing the net salvage percentage for depreciation accrual rates consistently with the new practice[1] of recording the cost of removal as the most appropriate methodology. Therefore, according to witness Spanos, the cost of removal for each project will be charged to accumulated depreciation at the same time the Company accrues for the net salvage value in rates. Witness Spanos asserted that this consistent treatment properly assigns costs to those ratepayers receiving benefit for the asset while in service; this applies to all accounts.

[1] Elsewhere in the Aqua Order it is made clear that "new practice" means "new for this applicant," not new for the accounting profession. Prior to Aqua's 2011 rate case, Aqua North Carolina had not been computing net salvage values as part of depreciation expense.

Aqua Order at 70. Aqua witness Spanos further explained that the entire cost of the asset, including costs of removal, should be recovered over the useful life of the asset and not recovered from customers after the asset's useful life had ended. *Id.*

In its order the Commission disagreed with the Public Staff's position and instead sided with the Company and its depreciation expert, witness Spanos, finding that

> utilizing the net salvage value percentage for depreciation accrual rates consistently with the new practice of recording the cost of removal is the most appropriate methodology. The Commission understands that using this methodology, the cost of removal for each project will be charged to accumulated depreciation at the same time the Company accrues for the net salvage in rates. *This treatment properly assigns costs to those ratepayers receiving benefit for the asset while in service and properly applies to all accounts.*

Id. at 72 (emphasis added).

In addition, the Commission notes that at least one of DENC's peer utilities regulated by the Commission, Duke Energy Progress, did understand the need to address costs of closure of coal ash impoundments in depreciation allowances, although the amount to be recovered by DEP through depreciation proved inadequate to cover its actual final costs of closure. *See* DEP Rate Case Order, at 42, 138.

In the quote above from DENC Late-Filed Exhibit No. 3, the Company stated that it has relied, in part, on its depreciation consultant for the position it has taken. The Company's expert on depreciation is the firm of Gannett Fleming, Inc., and more specifically Mr. John J. Spanos of that firm. Mr. Spanos signed the cover letters accompanying DENC's 2011 and 2016 depreciation studies as Senior Vice President, Valuation and Rate Division. *See* Docket Nos. E-22, Subs 459 and 479 (updated 2011 depreciation study filed in Docket No. E-22, Sub 493 on April 1, 2013); and Sub 532 (updated 2016 depreciation study filed in Docket No. E-22, Sub 562 on August 21, 2019).

Mr. Spanos has frequently appeared before the Commission and is well-recognized in his field. Although he provided no testimony in the present case, on the point now at issue the Commission finds it appropriate to take judicial notice of testimony he provided in 2015 before the South Dakota Public Utilities Commission where he testified on behalf of Black Hills Power, Inc., an electric utility regulated by the South Dakota Commission.[1] This testimony was filed on January 15, 2015, before the date of the Company's most recent depreciation study for its 2016 North Carolina rate case filing.

[1] Rebuttal Testimony and Exhibit of John J. Spanos, *Application of Black Hills Power, Inc., for Authority to Increase Rates in South Dakota*, No. EL14-026 (S.D.P.U.C. Apr. 17, 2015), *reh'g denied*, (S.D.P.U.C. May 29, 2015), https://puc.sd.gov/commission/dockets/electric/2014/EL14-026/rebuttalbhp/ spanostestimony.pdf

In the Black Hills Power case an intervenor objected to Mr. Spanos' inclusion of the costs of decommissioning (net salvage value) in the proposed depreciation rates for the utility's coal-fired generating plants. The intervenor's position was that such costs should be recovered only at and after the time of decommissioning when they could be known and measured with certainty. Rejecting that view, Mr. Spanos testified:

> The primary depreciation issue in this case is whether the Company will experience terminal net salvage for their power plants when they are eventually retired. Experience now shows that not only will power plants be retired, but there are significant costs upon retirement related not only to the dismantlement of the plant itself, but also to the remediation of features of the site such as ash ponds. Since these costs are likely to be incurred, intergenerational equity and depreciation authorities require that they be included in depreciation and recovered over the service lives of the plants.

Pre-Filed Rebuttal Testimony of John J. Spanos, *Application of Black Hills Power, Inc., for Authority to Increase Rates*, No. EL14-026, at 4 (S.D.P.U.C. Apr. 17, 2015).

Asked to provide examples of the types of costs to which he was referring, Mr. Spanos testified:

> Duke Energy plans to decommission a number of sites in the Carolinas, and activities related to the retirement of these sites include asbestos removal, demolition and the closure of ash ponds. Dominion Virginia Power is in the process of decommissioning coal units at its Chesapeake Energy Center, North Branch and Yorktown sites.

Id. at 8 (similar testimony given at pp. 9-11).

Buttressing his position by referring to other published authorities, he noted:

> The [Uniform System of Accounts] prescribes that net salvage costs should be accrued over the course of an asset's service life (i.e., recognized in each period in which the asset provides service) in a systematic and rational manner. *Net salvage costs should not be recognized in the period in which any salvage-related costs are paid and should not be recovered after these costs are incurred.*

Id. at 15 (emphasis added).

Finally, responding to the intervenor's position that net salvage and cost of removal should remain a fixed value over the entire life of an asset and should not be updated or adjusted, Mr. Spanos testified that not only was period reassessment and updating proper but that it was in fact required as new information became available. *Id.* at 17-18.

Mr. Spanos' testimony before the South Dakota Public Utilities Commission, and his testimony before this Commission in Docket No. W-218, Sub 319 referred to earlier, is a clear rebuke to the Company's position in this case. His views are not idiosyncratic; they are fully in line with widely accepted authority. Mr. Spanos provided the following from the 1996 NARUC manual entitled *Public Utility Depreciation Practices*:

> Historically, most regulatory commissions have required that both gross salvage and cost of removal be reflected in depreciation rates. The theory behind this requirement is that since most physical plant placed in service will have some residual value at the time of retirement, the original cost recovered through depreciation should be reduced by that amount. Closely associated with this reasoning is the accounting principle that revenues be matched with costs and the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, no more, no less. The application of the latter principle also requires that the estimated cost of removal of plant be recovered over its life.

NARUC, *Public Utility Depreciation Practices* 157 (1996).

In addition, Mr. Spanos quoted the following from the 1994 edition of *Depreciation Systems*.

> The matching principle specifies that all costs incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring an asset currently in service must be accrued and allocated as part of the current expenses.

W. C. Fitch and Frank K. Wolf, *Depreciation Systems* 7 (1994).

How, then, does this principle apply in this case to the recovery of the costs for closure of DENC's waste coal ash management facilities? Recognizing the inherent difficulty in accurately forecasting expenditures that will materialize only many years into the future and that must also accommodate evolving standards of industry practice and regulatory requirements, the Commission concludes that it would be unfair to deny recovery altogether based solely on the fact that the Company made no attempt to collect the costs from earlier generations of ratepayers. But by the same token, complete recovery at the expense of current and future ratepayers cannot be squared with the bedrock principles just reviewed. In the end, the Commission concludes that the balancing that will be achieved by a ten-year amortization of DENC's CCR costs without a return is further supported by the failure of DENC to properly account for the full decommissioning costs of its coal-fired power plants and to collect its best reasonable estimate of those costs as part of depreciation allowance, adjusted from time to time as new information was acquired. In addition, the Commission finds good cause to direct that in DENC's next update of its depreciation study it should account for its projected CCR remediation and closure costs in the decommissioning expenses for its coal-fired power plants.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 59-62

The evidence supporting these findings of fact and conclusions is contained in the direct testimony of Public Staff witness Lucas, and the Post-Hearing Exhibits of DENC.

In his testimony, witness Lucas explained that the Public Staff investigated whether the Company has environmental or general liability insurance that would provide coverage for its CCR-related costs, and that the Public Staff reviewed notices, claims, and related documents sent by the Company to insurers that relate to CCR. Tr. vol. 6, 196. Based on the Public Staff's review, witness Lucas recommended that the Commission monitor the Company's existing and potential insurance claims. He stated that if any insurance proceeds are ultimately received or recovered, the Commission should require that the Company place all such proceeds into a regulatory liability account to either be disbursed back to ratepayers or to offset the costs to ratepayers of the Company's CCR-related costs. *Id.* at 197.

DENC's Confidential Post-Hearing Exhibit No. 2, filed herein on October 23, 2019, includes the details of the potential insurance policy recoveries related to possible CCR liabilities of DENC.

Discussion and Conclusions

To the extent that ratepayers are required to pay the costs of CCR remediation, and DENC's insurance policies cover some of those costs, ratepayers should receive all or a portion of the insurance proceeds. In that regard, DENC is representing the interests of its ratepayers in pursuing the insurance claims. Therefore, the Commission finds it appropriate to hold DENC to the same standard of care that DENC is required to exercise in providing electric service. That standard is one of reasonableness and prudence. In subsequent proceedings, if the parties or the Commission raise meritorious issues about DENC's representation of the interests of ratepayers in the insurance claims, DENC shall bear the burden of proving that it exercised reasonable care and made prudent efforts to obtain the maximum recovery from the insurance claims.

Further, the Commission concludes that DENC should be required to place all insurance proceeds received or recovered by DENC in the insurance claims in a regulatory liability account and hold such proceeds until the Commission enters an order directing DENC as to the appropriate disbursement of the proceeds. In addition, the regulatory liability account shall accrue a carrying charge at the overall rate of return authorized for DENC in this Order.

Finally, based on the risk sharing allocation of CCR costs adopted by the Commission, DENC is entitled to retain a percentage of the CCR insurance proceeds equal to the above weighted average equity capital financing.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 63

The evidence supporting this finding of fact and these conclusions is contained in the findings and conclusions of the Commission herein pertaining to authorized cost deferrals by DENC.

In the present case, the Commission is approving DENC's post-in-service costs of the Greensville CC and recovery through amortization of a previously deferred portion of DENC's CCR costs. The Commission notes that a deferred cost is not the same as the other cost of service expenses recovered in the Company's non-fuel base rates. A deferred cost is an exception to the general principle that the Company's current cost of service expenses should be recovered as part of the Company's current revenues. When the Commission approves a typical cost of service, such as salaries and depreciation expense, there is a reasonable expectation that the expense will continue at essentially the same level until the Company's next general rate case, at which time it will be reset. On the other hand, when the Commission approves a deferred cost the Commission identifies a specific amount that has already been incurred by the Company, or, in the case of CCR costs, is estimated to be incurred by the Company. In addition, the Commission sets the recovery of the amount over a specifie period of time. Further, the Company is directed to record the recovery of the specific amount in a regulatory asset account, rather than a general revenue account. If DENC continues to recover that deferred cost for a longer period of time than the amortization period approved by the Commission that does not mean that DENC is then entitled to convert those deferred costs into general revenue and record them in its general revenue accounts. Rather, the Company should continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for those deferred costs until the Company's next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 64-65

The evidence supporting these findings of fact and conclusions is contained in the DENC's verified Application and Form E-1, the testimony and exhibits of the witnesses, the Public Staff Stipulation, and the entire record in this proceeding.

Summary of the Evidence

In the Application and initial direct testimony and exhibits, DENC provided evidence supporting an increase of approximately $27 million in its annual non-fuel revenues from its North Carolina retail electric operations. With regard to fuel, in his direct testimony Company witness McLeod testified that the Company annualized fuel clause revenue by applying the current base fuel rate plus Rider A to the annualized and normalized customer usage at June 30, 2019. Witness McLeod also explained that an adjustment was made to fuel clause expense to make fuel clause expense equal to fuel clause revenue, net of the regulatory fee. Tr. vol. 4, 260.

On August 5, 2019, the Company filed supplemental direct testimony and exhibits updating several cost of service adjustments. These updated adjustments decreased the Company's revenue requirement by approximately $2.1 million, for a revised increase in North Carolina retail revenue of $24.9 million, which was reduced again in the Company's additional supplemental testimony filed on September 12, 2019, to $24.2 million.

On August 23, 2019, the Public Staff filed the direct testimony of witness Johnson, presenting her recommended accounting and ratemaking adjustments to the Company's proposed revenue requirement. Accounting for these adjustments, she recommended a decrease in the Company's annual base non-fuel operating revenue of $8,112,000. Witness Johnson also testified that the Public Staff adjusted the fuel clause expense to reflect the base fuel rate and Rider A as set forth in the Additional Supplemental Testimony of DENC witness Haynes and recommended by Public Staff witness Jack Floyd, subject to the outcome of the Company's currently ongoing fuel proceeding in Docket No. E-22, Sub 579. Witness Johnson stated that this adjustment resulted in a decrease of $2.155 million from the fuel expense originally included in the Company's Application. Tr. vol. 6, 39.

On September 17, 2019, the Company and the Public Staff entered into and filed the Public Staff Stipulation. Also on September 17, 2019, the Company filed the testimony of witnesses McLeod, Miller, Hevert, Davis, and Haynes in support of the stipulated revenue increase. These witnesses testified in support of the accounting and ratemaking adjustments agreed upon in the Public Staff Stipulation. They also testified that the Public Staff Stipulation is the result of negotiations between the Stipulating Parties. Also on September 17, 2019, the Public Staff filed the Joint Stipulation testimony of witnesses Johnson and McLawhorn, recommending and supporting the stipulated adjustments to the Company's requested revenue increase while also noting the unresolved issues related to CCRs.

The Public Staff Stipulation, as shown on Settlement Exhibit I, reflects the Company's proposed increase in the revenue requirement of $6.428 million, consisting of an increase of $8.583 million in non-fuel revenues and a decrease of $2.155 million in base fuel revenues, and the Public Staff's proposed increase in the revenue requirement of $2.037 million, consisting of an increase in $4.192 million in non-fuel revenues and a decrease of $2.155 million in base fuel revenues. The difference between the Company's and the Public Staff's proposals in the Public Staff Stipulation result from the unresolved issues identified at Section II.A.i of the Public Staff Stipulation (cost recovery of the Company's CCR costs, the recovery amortization period, and return during the amortization period).

Discussion and Conclusions

As discussed in the body of this Order, the Commission approves the Public Staff Stipulation, with the exception of section VII.A, and makes its individual rulings on the unresolved issues as discussed herein. As the unresolved issues pertaining to CCR cost recovery, and the Commission's decision in this Order on the conversion costs at Chesterfield Units 3 and 4, were not addressed by the Public Staff Stipulation and accompanying testimony and exhibits, the Commission requests that DENC recalculate the required annual revenue requirement consistent with all of the Commission's findings and rulings herein as soon as practicable following the issuance of this Order. The Commission further orders DENC to work with the Public Staff to verify the accuracy of the recalculations. Once the Commission receives this filing, the Commission will work promptly to verify the calculations and will issue an order with final revenue requirement numbers. DENC should provide electronic copies of this filing to the Commission, complete with formulas intact.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 66

The evidence supporting this finding of fact and these conclusions is contained in the verified Application, the testimony and exhibits of the DENC and Public Staff witnesses, the Public Staff Stipulation, and the record as a whole.

Pursuant to N.C.G.S. § 62-133(a), as described earlier, the Commission is required to set rates that are "fair both to the public utilities and to the consumer." In order to strike this balance between the utility and its customers, the Commission must consider, among other factors: (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. N.C.G.S. § 62-133(b). DENC's continued operation as a safe, adequate, and reliable source of electric service for its customers is vitally important to DENC's individual customers, as well as to the communities and businesses served by DENC. DENC presented credible and substantial evidence of its need for increased capital investment to, among other things, maintain and increase the reliability of its system and comply with environmental requirements.

For example, DENC witness Mitchell testified that during the last three years, the Company invested $1.3 billion to bring online a total of 1,588 MW of new generation in the Greensville County CC. Witness Mitchell stated that this new generation is cleaner and highly-efficient combined cycle generating capacity that has the potential to create substantial fuel savings due to very favorable current natural gas prices. Witness Mitchell also noted that the Company has invested $132 million to bring on-line three regulated solar facilities totaling 56 MW and between 2019 and 2020 plans to invest approximately $410 million to bring on-line an additional 240 MW of nameplate solar capacity. Witness Mitchell also testified that the Company has received a certificate of public convenience and necessity to construct the 12 MW Coastal Virginia Offshore Wind Project that is expected to come on-line in 2020. Finally, witness Mitchell explained that the Virginia Grid Modernization and Security Act specified that up to 5,000 MW of solar and wind generation facilities constructed by a utility such as the Company are in the public interest and the Company has committed to have approximate 3,000 MW placed in service or under development by the end of 2022. Tr. vol. 6, 171-72.

Witness Mitchell further testified that DENC has spent approximately $268 million on transmission improvements in North Carolina during the last three years. He stated that these improvements support improved reliability of the transmission system and local economic growth. He also testified that the Company plans to invest an additional $200 million in transmission improvements in North Carolina over the next five years. Tr. vol. 6, 173-74.

In addition, witness Mitchell testified that DENC has invested over $29 million in its distribution system in North Carolina during the last three years. He stated that these investments balance the need for reliable service with prudent spending. *Id.*

Witness Mitchell also testified regarding the impact of current and proposed environmental regulations on the Company's operations. He stated that during the last decade electric utilities have been required to address compliance with a suite of new environmental standards adopted by the EPA. He testified that compliance with these standards has directly impacted DENC's operation of its coal-fired generating plants, citing as an example the EPA's Mercury Air Toxics Standards Rule, which led to the retirement of over 900 MW of coal-fired generating capacity. Witness Mitchell also stated that the enactment of the CCR Rule in April 2015 created a legal obligation for the Company to retrofit or close all of its inactive and existing ash ponds, as well as perform required monitoring, corrective action, and post-closure activities as necessary. *Id.* at 170-76.

Moreover, witness Mitchell testified that DENC plans to invest $11.1 billion over the next three years for generation, transmission, and distribution investments in order for the Company to continue to fulfill its obligations of providing reliable, cost-effective service in an environmentally responsible manner for DENC's customers. *Id.* at 177.

These are representative examples of the capital investments that have been made and are planned to be made by DENC in order to continue providing safe, reliable, and efficient electric service to its customers. Based on all of the evidence, the Commission finds and concludes that the rates established herein strike the appropriate balance between the interests of DENC's customers in receiving safe, reliable, and efficient electric service at the lowest possible rates, and the interests of DENC in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the rates established by this Order are just and reasonable under the requirements of N.C.G.S. § 62-130, et seq.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by DENC and the Public Staff is hereby approved, with the exception of Section VII.A;

2. That DENC shall consult with the Public Staff in accordance with the directive in the body of this Order, and shall remove from its revenue requirement and rate base all North Carolina retail jurisdictional costs and effects arising from the wet to dry CCR conversion project for Units 3 and 4 of the Chesterfield Power Station;

3. That the Stipulation filed by DENC and CIGFUR is hereby approved in its entirety;

4. That DENC shall recover from its North Carolina retail ratepayers its CCR Costs incurred during the period July 1, 2016, through June 30, 2019;

5. That the Company's CCR Costs shall be amortized and recovered from ratepayers over a ten-year period;

6. That during the amortization and recovery of the CCR Costs the CCR costs shall not earn a return;

7. That DENC shall be allowed to recover its financing costs incurred during the Deferral Period and up to the effective date of new rates approved in this Order, at the Company's previously authorized weighted average cost of capital;

8. That the Company shall use annual compounding for calculating the financing costs deferred costs during the Deferral Period;

9. That DENC shall maintain complete records of all environmental management activity and test results that pertain to its coal ash management program, and make such records available to the Public Staff and the Commission upon request and in the format that is reasonably requested by the Public Staff and the Commission;

10. That as soon as practicable following the issuance of this Order DENC shall file with the Commission the annual revenue requirement and accompanying rate schedules and terms and conditions that are consistent with the findings and conclusions of this Order and the Public Staff Stipulation, with the exception of Section VII.A. The Company shall work with the Public Staff to verify the accuracy of the filing. Further, DENC shall file schedules summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding;

11. That DENC is hereby authorized to adjust its rates and charges in accordance with the findings in this Order effective for service rendered on and after the following day after the Commission issues an Order accepting the calculations required by Ordering Paragraph No. 10;

12. That the Commission shall issue an order as soon as reasonably practicable approving the final revenue requirement numbers once received from DENC and verified by the Public Staff;

13. That the proper jurisdictional average base fuel factor for this proceeding is 2.089¢/kWh, excluding regulatory fee, and 2.092¢/kWh, including regulatory fee. The Company shall replace the voltage-differentiated base fuel factors approved in Sub 532 with the following voltage-differentiated base fuel factors, including regulatory fee, effective February 1, 2020:

Customer Class	Base Fuel Factor
Residential	2.118 ¢/kWh
SGS & PA	2.115 ¢/kWh
LGS	2.098 ¢/kWh
NS	2.036 ¢/kWh
6VP	2.065 ¢/kWh
Outdoor Lighting	2.118 ¢/kWh
Traffic	2.118 ¢/kWh

14. That the jurisdictional and class cost allocation, rate design principles, and service regulations proposed by the Company, and agreed upon in the Public Staff Stipulation, are approved and shall be implemented;

15. That DENC shall implement Rider EDIT as described in Section VIII of the Public Staff Stipulation. Further, although not specifically outlined in the Public Staff Stipulation, it is appropriate that in this proceeding DENC's fully-adjusted cost of service includes the income tax benefit arising from the annual amortization of federal protected EDIT during the test year, thereby incorporating a going-level of federal protected EDIT amortization per the IRC's normalization rules in base non-fuel rates;

16. That as soon as practicable after the date of this Order, DENC shall file for Commission approval five copies of rate schedules designed to comply with the rate design approved in this Order accompanied by calculations showing the revenues that will be produced by the rates for each schedule. This shall include a schedule comparing the revenue produced by the filed schedules during the test period with the revenue that will be produced under the rate schedules to be approved herein and a schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule;[1]

17. That as soon as practicable after the issuance of the last Commission Order in DENC's four pending rate-related proceedings, which are this proceeding, the Sub 579 fuel charge adjustment proceeding, the Sub 578 renewable energy and energy efficiency portfolio standard (REPS) cost recovery proceeding, and the Sub 577 demand-side management (DSM) proceeding, DENC shall file a consolidated proposed customer notice addressing the rate changes associated with the non-fuel base and base fuel rate changes approved in this proceeding (Sub 562), the Fuel

[1] If necessary, the Commission will address in a subsequent order any refund due ratepayers based on any differences in the rates approved in this Order and the Company's temporary rates implemented on November 1, 2019.

Rider B in the Sub 579 proceeding, the REPS Rider RP and RPE rate changes in Sub 578, and the DSM Rider C and Rider CE rate changes in Sub 577. Such notice shall include the effect of each rate-related proceeding on a residential customer using 1,000 kWh and the combined effect of all four rate-related proceedings on a residential customer using 1,000 kWh. Upon approval by the Commission, DENC shall notify its North Carolina retail customers of the foregoing rate adjustments by including the approved notice as a bill insert with customer bills rendered during the next regular scheduled billing cycle;

18. That the Company shall continue to annually file a cost of service study with the Commission using the Summer/Winter Peak and Average methodology;

19. That in its next general rate case, the Company shall file the results of a class cost of service study with production and transmission costs allocated on the basis of the Summer/Winter Coincident Peak method in addition to the SWPA used in this proceeding and consider such results for the sole purpose of apportionment of the change in revenue to the customer classes;

20. That if DENC receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case;

21. That the Company shall work with CIGFUR to consider whether certain provisions within its RTP rates should be modified and, if there is mutual agreement between CIGFUR and DENC to such modifications, and CIGFUR indicates that at least one of its member customers is willing to take service under such rates, DENC shall re-file such rates with the Commission for approval with the modifications agreed upon within 60 days of such agreement;

22. That within ten days of the resolution by settlement, judgment, or otherwise of the pending and future CCR insurance claims, DENC shall file a report with the Commission explaining the result and stating the amount of insurance proceeds to be received or recovered by DENC. This reporting requirement shall apply even if there is litigation appealed to a higher court;

23. That DENC shall place all CCR insurance proceeds received or recovered by DENC from pending and future insurance claims in a regulatory liability account and hold such proceeds until the Commission enters an order directing DENC as to the appropriate disbursement of the proceeds. The regulatory liability account shall accrue a carrying charge at the net-of-tax overall rate of return authorized for DENC in this Order; and

24. That in DENC's next update of its depreciation study it shall account for its projected CCR waste management facility decommissioning and closure costs in the decommissioning expenses for its coal-fired power plants.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of February, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

Commissioner Daniel G. Clodfelter concurs in part and dissents in part.

DOCKET NO. E-22, SUB 562
DOCKET NO. E-22, SUB 566

Commissioner Daniel G. Clodfelter concurring in part and dissenting in part:

I concur in the result reached by the Commission on all issues save two, and as to those two matters I dissent. In addition, though I join in the outcome on all other matters, some of my thinking on those matters is not fully captured by the Commission's opinion and order, and I write to elaborate my views on certain issues. I address first the two points on which I would reach a different result.

Rate Design and Fixed Monthly Charge

For the reasons set forth in my dissent in the DEC Rate Order in Docket No. E-7, Sub 1146 (June 22, 2018), which I will not repeat here, I do not support the Company's proposal to increase the fixed monthly charge to residential customers and would find the proposal unsupported on this record. My view, as set out in my dissent in the DEC Rate Order, is that the Company's fixed monthly charge should be calculated with reference to cost allocation that employs the "basic customer method" to assign distribution system costs, but in any event the Company's current fixed charge, which relies in part on the "minimum system method" for allocating distribution system costs, should not be increased from its current level. (For a calculation of the results of using the "basic customer method" of cost allocation, see Company's Rate Allocation and Rate Design Late-Filed Exhibit 1.) Accordingly, I dissent as to Finding Number 40 approving the Company's proposed rate design, and therefore also as to Finding Number 66, wherein the Commission finds the Company's proposed rates, except as modified by the Commission's order, to be just and reasonable. I also take note of and agree with Finding Number 15.1., in which the Commission finds that "... some customers [of the Company] will struggle to pay their utility bills under the rate increases authorized herein." I believe this finding counsels against increasing the fixed portion of the Company's rates at this time.

Allowance of Financing Costs During Deferral Period

As to the second point, I dissent from Finding Number 54 and would instead find that the Company is not entitled to recover any amount greater than the approximately $19.2 million actually expended for costs related to waste coal ash during the Deferral Period. More specifically, I would not allow recovery of the approximately $2.7 million the Company has requested as alleged "financing costs" related to the actual $19.2 million in expenditures.[1]

The Commission has determined, and I agree, that neither the Actual CCR Expenditures nor the Deferral Period Return are entitled to earn any return during the period of amortization and will not be included in rate base. (Finding No. 53) Much of my reasons for supporting this result are set forth in my dissent in the DEC Rate Order in Docket No. E-7, Sub 1146 (June 22, 2018), and again I will not repeat them here. With respect to the allowance of what the Commission calls "financing costs," however, I can find no supportable basis for differentiating the Deferral Period from the amortization period.

The Commission proffers only one reason for this different treatment.[2] It states:

> ...[T]he Commission observes that such a return *may* reduce the incentive for the Company to apply for rate increases more frequently to avoid regulatory lag. While recovering financing costs incurred during the Deferral Period does not help with the Company's short-term cash flow, it means the Company ultimately does not experience lost financing costs if it delays a new rate case.

Order at 135 (emphasis added).

I am unpersuaded by this suggestion because I do not find in the record sufficient evidence that the potential "may" is more likely than not to translate to an actual "will." I find nothing in the evidentiary record that the amount of the Deferral Period Return – approximately $2.7 million – is sufficient to drive the Company's future decisions about whether or not to seek an adjustment of the rates approved in this proceeding. On the record in this case, it is far, far more likely that the timing of future rate change applications will be driven by the planned capital investments identified by Company witness Mitchell and discussed by the Commission in its analysis in support of Finding No. 66 – e.g., the Company's commitment to place into service 3,000 MW of new solar and wind generation capacity by 2022 (Tr. vol. 6, 171-72), the Company's plans to spend some $200 million in transmission upgrades in North Carolina over the next five years (Tr. vol. 6, 173-74), and the Company's overall plan to invest some $11.1 billion in the aggregate in generation, transmission, and distribution system improvements over the next three years. *Id.* at 177. It is expenditures such as these that will determine when the Company next seeks a

[1] The Commission's order defines the capitalized term "CCR Costs" to include both the $19.2 million in actual expenditures on activities related to coal ash and also the sum of $2.7 million labelled "financing costs." The term "financing costs" is a euphemism for the authorized weighted average cost of capital, which includes the costs of third-party debt but also a return on equity. For clarity, hereafter I will refer to the first component as "Actual CCR Expenditures" and the second component as "Deferral Period Return."

[2] The Commission's order also notes that the Public Staff did not oppose allowing recovering of financing costs during the Deferral Period. This I consider a statement of fact concerning a party's position in the case; it is not a rationale justifying the Commission's decision. The Commission is not constrained by the Public Staff's position; indeed, in this case the Commission has declined to accept the settlement position of the Public Staff concerning the ratemaking treatment of certain costs for the dry ash conversion project as related to Chesterfield Units 3 and 4. Irrespective of the Public Staff's or any other party's position on an issue, the Commission is required to consider all of the evidence and exercise its independent judgment to set just and reasonable rates. *State ex rel. Utilities Commission v. Carolina Utility Customers Ass'n, Inc.*, 348 N.C. 452, 466, 500 S.E.2d 693, 703 (1998).

change in its rates and not whether it is allowed in this case to recover $2.7 million on account of monies already expended on coal ash remediation and closure activities over the three years prior to this case. *Id.* at 177.[1]

Beyond this, I find it difficult to harmonize the Commission's decision on this point with Findings of Fact Nos. 56 through 58 and the discussion and analysis supporting those findings, which I fully endorse and support. The Commission has found that in analyzing, proposing, and seeking the establishment of rates that included allowances for depreciation associated with its coal-fired generating units the Company failed to include any amounts for the costs of final remediation or closure of the waste ash management units associated with these plants. Had the Company done so, then at least some portion, if not all, of the costs for which it now seeks recovery, including the Actual CCR Expenditures for the Deferral Period, would have been recovered as an annual operating expense as part of the rates applicable to service provided in earlier periods.[2] Put differently, had the Company properly anticipated, estimated, and collected as part of depreciation allowance amounts that were later required for Actual CCR Expenditures made during the Deferral Period, it would have thereby accrued a reserve from the revenues earned under prior rates that could have been used to offset or avoid some, if not all, of the Deferral Period Return that it now seeks and that the Commission has approved. I cannot reconcile the Commission's admonishment that the Company did not properly account for or seek recovery of the Actual CCR Expenditures, as part of net salvage value included in depreciation allowance, with the Commission's acceptance of the Company's present request that it be allowed the Deferral Period Return in order to assist in managing the cash flow needs associated with its CCR remediation and closure activities.

[1] In this proceeding the Commission authorizes recovery of the Deferral Period Return on a backward-looking basis. It is interesting that neither the Company's stipulation and settlement with the Public Staff in its 2016 general rate case, Docket No. E-22 sub 532, nor the Commission's order in that case discussed the issue of recovery of "financing costs" for expenditures made on CCR remediation and facility closure after June 30, 2016, and during the period prior to the Company's next succeeding general rate case, now the present case. Apparently, in 2016 the Company was willing to go forward to its next rate case with no assurance that it would be able to recover its "carrying costs" on CCR expenditures made in the interim period. Approximately three years elapsed from that time until the present case, and on the present record I am unable to conclude that the timing of the present case was dictated by the "carrying cost" of CCR expenditures instead of by other factors. It is far more likely that the timing of the present case was influenced by the Company's desire to bring the new $1.3 billion Greensville combined cycle plant into rate base.

[2] As noted in the Commission's discussion of the issue, the point here is not that the Company was tasked with perfect foresight as to its ultimate, actual CCR remediation and facility closure costs but instead that it made no reasonable effort to make any estimate of such costs or recover any such estimate as part of depreciation allowances. Had it done so, the cash flow impact of some portion, if not all, of the Actual CCR Expenditures would have been covered by the revenues recorded to recover depreciation expense.

"Equitable Sharing" By Any Other Name ....[1]

The Commission professes to reject the Public Staff's "equitable sharing" position as being inconsistent with accepted ratemaking principles and attempts to differentiate the Public Staff's position from its own effort to strike a "fair balance" between ratepayers and shareholders.[2] Order at 136-137. I am unable to join in the Commission's reasoning for the straightforward reason that the ultimate result reached by the Commission amounts, in concept, to exactly the same thing as advocated by the Public Staff. The outcome of the Public Staff's proposal and that of the Commission's analysis differs only in the fact that the Public Staff recommended an eighteen-year period of amortization of allowed costs rather than the ten-year amortization period adopted by the Commission. Indeed, much of the reasoning offered by the Commission is the same as that invoked by the Public Staff to support its own "equitable sharing" proposal, including the Commission's reliance on the analysis and authority of, among other precedent, the MGP Order and the Anna/Surry Order. Order at 130-131.[3]

I concur with both the Commission's order and with the Public Staff that there is ample legal basis for the Commission to allocate or divide the cost burden between ratepayers and the Company's shareholders. For myself, the point of difference I have with the Public Staff is not over the concept of "equitable sharing" or the legal basis for application of that concept, but over the specific equities of this case that warrant invoking it. I find sufficient support for the result reached by the Commission in the analysis and discussion associated with Findings of Fact Numbers 56 through 58, and I do not need to go further than the scope of those findings to reach that result. The Company's failure to make any provision over the useful lives of its coal-fired generating plants for recovery of the ultimate costs of remediation and closure of waste coal ash management facilities is ample ground for the Commission to find that a portion of the costs now incurred for such remediation and closure must be borne by the Company itself and not by present and future ratepayers. The Commission's selection of a ten-year period for amortization of those costs achieves a fair and reasonable balance of cost-sharing between ratepayers and the Company.

A Question for the Future

Following promulgation of the CCR Rule, the Company's plan for closure of waste ash surface impoundments at all of its plants was to dewater the ash, place a permanent cap over the

[1] What's in a name? That which we call a rose by any other name would smell as sweet ..." *Romeo and Juliet*, Act II, Scene II.

[2] E.g. Order at 131, referring to the "well-established history" of Commission decisions seeking to establish a "fair and reasonable" balance between ratepayers and shareholders; Order at 132, referring to the objective of striking "the appropriate balance between shareholder and customer interests to set just and reasonable rates"; and Order at 135, noting that the ten-year period of amortization approved by the Commission "...strikes the more appropriate and fairer balance" than does the position of either the Company or the Public Staff.

[3] The Commission's reasoning that most closely parallels the Public Staff's "equitable sharing" analysis is contained in its discussion of whether the Company should be allowed to earn a return on the unamortized balance of the CCR Costs (Order at 130-134), but I consider immaterial the rubric under which the discussion is placed. I acknowledge, of course, that the Commission does not rely upon the Public Staff's notion of "culpability." With this difference, however, the analysis otherwise runs very similarly.

The Limitations of Finding Number 51

I concur in the Commission's Finding Number 51. I do so as much because of what is not said in that finding as what is said. The Commission does not in this case find and conclude that the Company – over a period of many years and at multiple sites – prudently managed waste coal ash. It finds only that the particular items of expenditure for which recovery is sought in this case cannot be causally connected to specifically identifiable imprudent acts or omissions based on the record evidence presented to the Commission. The expenditures at issue in this case would likely have been incurred in all events upon final closure of the waste ash management units. They involved activities such as characterizing the wastes, calculating volumes, preliminary design and engineering of closure plans, legal review and vetting of closure plans, permitting and regulatory oversight activities, water sampling and monitoring, and dewatering and consolidating ash for ultimate disposal. (Although the total cost of these activities is included in DENC's testimony as public information, the separate cost of each activity was filed by DENC under seal as a proprietary trade secret in Confidential Company Late-Filed Exhibits 5 and 6, and Supplemental Late-Filed Exhibit 5). The Public Staff presented no evidence that either the specific activities at issue or the amount of the costs expended were causally related to any acts or omissions that could on the present record be found to be imprudent.

The Commission's order thus preserves for the future certain questions that were not fully explored in the present case. One example of such a question, which I offer for purposes of illustration only, concerns the Company's failure to take prompt steps to permanently stabilize and close the surface impoundments at the Possum Point plant after the plant was converted to natural gas in 2003 and the impoundments ceased receiving coal ash waste. In light of the Company's knowledge of possible groundwater degradation associated with these impoundments (*See* Tr. vol. 6, 145-157), it may be pertinent to examine in greater detail the Company's failure to take action to permanently close the impoundments in 2003 and whether or not the delay in commencing final closure activities until after adoption of the CCR Rule can be causally linked to any subsequent remedial or closure costs that could have been avoided if earlier action had been taken. The parties differ greatly as to the standard of conduct that should be applied in evaluating the Company's actions and omissions at Possum Point in 2003 and prior to the adoption of the CCR Rule, but it is not necessary to decide this point in the present proceeding. I offer this example not to express any judgment on the matter but merely to show that the limited scope of Finding Number 51 may not be a matter of purely theoretical interest.

contents, and close the impoundments in place. This plan has been superseded by the adoption of Virginia Senate Bill 1355, codified at Va. Code Ann. §10.1-1402.03 (2019) (the Chesapeake Coal Ash Act) for the waste ash management units located within the Chesapeake Bay watershed. The Chesapeake Coal Ash Act applies to the coal ash management units at the Company's Bremo, Possum Point, Chesapeake and Chesterfield plants, requiring the excavation and removal of waste ash for permanent disposal outside the watershed. Company witness Williams testified that the impact of this legislation did not increase any of the costs or change any of the activities for which cost recovery is requested in this case but that the Act may likely affect future impoundment closure activities and the resulting costs for which recovery will be sought in future rate cases. Tr. vol. 5, 93. I believe it is important, because the parties did not develop the issues in their evidentiary presentations or their briefing and because on this record it is not ripe for decision, that the Commission signal to the parties that two potential matters remain for determination in future rate cases: (1) whether the Company's record of management of waste coal ash, especially with respect to the surface impoundments at the four plants affected by the Chesapeake Coal Ash Act, may have prompted or contributed to the Act's elimination of the Company's preferred "cap in place" closure method and, if it did so, to what extent the costs of remediation and final closure of those waste management facilities may be increased due to requirements of the Act more stringent than those of the CCR Rule, and (2) whether or not, independently of the preceding question, any incremental or enhanced costs resulting from compliance with the Chesapeake Coal Ash Act may be recovered from North Carolina ratepayers. The first of these questions speaks to an issue of prudence; the second is jurisdictional. I express no view on either of these questions at this time, but I note that the Company and other interested parties should be prepared, in the appropriate proceeding and at the appropriate time, to present evidence concerning the amount, if any, by which the Company's coal ash remediation and waste management facility closure costs at the Bremo, Possum Point, Chesapeake, and Chesterfield plants were or have been increased, due to changes in scope or extent, over what those costs would have been had those waste management facilities been remediated and closed under the provisions of the CCR Rule.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

ONE-HUNDRED TENTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

Volume II

ISSUED FROM
JANUARY 1, 2020 THROUGH DECEMBER 31, 2020

ONE-HUNDRED TENTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2020, through December 31, 2020

Charlotte A. Mitchell, Chair

ToNola D. Brown-Bland, Commissioner

Lyons Gray, Commissioner

Daniel G. Clodfelter, Commissioner

Kimberly W. Duffley, Commissioner

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BY THE COMMISSION: On February 24, 2020, the Commission issued its Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase in the above-captioned dockets (Rate Order).

On April 24, 2020, Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC or Company), filed a Motion for Reconsideration or Clarification of the Rate Order (DENC's Motion). On the same date the Public Staff filed a Motion for Reconsideration or Clarification of the Rate Order (Public Staff's Motion).

DENC'S MOTION

DENC requested that the Commission reconsider three of the decisions made by the Commission in the Rate Order that relate to the costs incurred by DENC during the period from July 1, 2016 and running through June 30, 2019 to manage liabilities associated with coal combustion residuals (the CCR Costs): (1) that DENC should have included its CCR Costs in its depreciation expense and must do so in future depreciation studies; (2) that the Company cannot earn a return on the unamortized balance of its CCR Costs over the amortization period; and (3) that DENC must amortize recovery of CCR Costs over ten years. In addition, DENC requested clarification that it may defer its CCR Costs incurred after June 30, 2019, for consideration in a future rate case proceeding. In support of its motion, DENC cited N.C.G.S. § 62-80, and several prior Commission decisions.[1]

[1] Order Denying Motions for Reconsideration and to Compel Discovery, Docket Nos. E-2, Sub 998, *et al.*, at 4, (Dec. 10, 2012) (noting "new evidence" as one of the permissible grounds for reconsideration in addition to change in

Inclusion of CCR Costs in Depreciation Expense

DENC requested that the Commission reconsider its decision requiring the Company to include CCR Costs as part of cost of removal in future depreciation studies. DENC contended that this approach is inconsistent with applicable accounting principles and impractical given the Company's recent retirement of several of its coal facilities.

According to DENC, under generally accepted accounting principles (GAAP) and Federal Energy Regulatory Commission (FERC) accounting rules, which the Commission has consistently held are applicable to the Company,[1] once the Company had a legal obligation to remediate CCR basins it was required to account for the costs as an asset retirement obligation (ARO),[2] and costs accounted for as AROs are not included in the cost of removal component of depreciation under GAAP[3] and FERC[4] rules. Therefore, the Company did not include CCR Costs as a component of cost of removal in its 2016 depreciation study.

In addition, DENC stated that the Commission was critical of the fact that the Company did not include CCR Costs in its past depreciation studies, but the Commission nonetheless approved the Company's depreciation expense in the Rate Order based on prior studies that did not include CCR costs. The Company further stated that the Commission's recent orders approved DENC's depreciation expense as reasonable despite the absence of any attempt to project possible future CCR Costs in depreciation expense.[5]

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circumstances or misapprehension of facts); Order on Reconsideration Amending Order and Scheduling New Hearing, Docket No. G-5, Sub 481, at 4, (May 21, 2007) (acknowledging that N.C.G.S. § 62-80 "permits the taking of ... additional evidence" in reconsideration proceedings); Order Denying Motion for Reconsideration and/or Clarification, Docket No. P-100, Sub 133, at 8 (July 28, 2003) (recognizing that the presentation of new evidence can merit reconsideration).

[1] "ARO accounting complies with the authoritative statements of GAAP, FERC, and this Commission." Order Accepting Stipulation, Deciding Contested Issues, and Requirements Revenue Reduction, Docket No. E-7, Sub 1146, at 284 (June 22, 2018) (2017 DEC Rate Order); *see also* Commission Rule R8-27.

[2] This legal obligation occurred on April 17, 2015, when the United States Environmental Protection Agency published the final Coal Combustion Residuals Rule in the *Federal Register*.

[3] *See* DENC witness McLeod's direct testimony at 21; NCUC Form E-1, Supplemental Item No. 10 at 24; and Public Staff Witness Maness' direct testimony, at 5-6.

[4] The FERC Uniform System of Accounts defines cost of removal as "the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling incidental thereto. *It does not include the cost of removal activities associated with asset retirement obligations that are capitalized as part of the tangible long-lived assets that give rise to the obligation*" (CFR Title 18, Chapter I, Subchapter C Part 101, Definition 10) (emphasis added). *See also* Public Staff witness Maness' direct testimony, at 6.

[5] *See* Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, Docket No. E-22, Sub 532, at 9 (Dec. 22, 2016) (2016 Rate Order) ("The costs of rate case and operating revenue deductions reflected in and underlying the Stipulation, as well as the level of operating revenues under present rates, were prudently and reasonably incurred."); Order Granting General Rate Increase, Docket No. E-22, Sub 479, at 15 (Dec. 21, 2012) ("The appropriate level of depreciation and amortization expense under present rates for use in this proceeding is $42,599,000."); Order Granting General Rate Increase, Approving Fuel Charge Adjustment, and Approving Stipulation and Supplemental Agreement, Docket No. E-22, Sub 459, at 12 (Dec. 13, 2010) ("The Commission finds and concludes that the annualized

DENC contended that the record in this proceeding is inadequate to support the Commission's findings of fact and departure from past precedent. As an example, DENC stated that the Commission relied on testimony in a 2015 South Dakota proceeding as its primary support. The Company maintained that the 2015 testimony predated the Company's 2016 depreciation study, which did not include 74% of the total CCR Costs presented in this proceeding because the relevant units were retired or had been impaired for financial reporting purposes. Further, the Company contended that the Commission's reliance on a 2011 water utility case[1] in support of its determination was misplaced because the Commission issued orders in the Company's 2010 and 2012 rate cases in which DENC did not include any CCR Costs in its depreciation rates and the Commission did not raise any concerns with that approach.

Further, DENC stated that the Commission's requirement that the Company include CCR-related ARO expenses in the cost of removal component of its depreciation expenses would only apply to a small subset of future CCR Costs because many of the generating units with outstanding CCR-related AROs have either been retired or have been impaired for financial reporting purposes; and therefore, will not appear in future depreciation studies. DENC noted that since the hearing the Company has made plans for the early retirement of the remaining coal units 5 and 6 at the Chesterfield Power Station by 2023, leaving only 4% of CCR-related ARO pertaining to coal units to be included in future depreciation studies.

Finally, the Company contended that the additional administrative burden for such a small percentage of remaining coal assets more than outweighs any ratemaking benefit and noted that the CCR cost recovery methods in Virginia and North Carolina are different. According to DENC, introducing amounts to the depreciation study process for a single jurisdiction will add the need for additional procedures and analysis to ensure that costs are properly segregated between depreciation and other legacy recovery mechanisms among jurisdictions.

In conclusion, the Company requested that the Commission reconsider its Findings of Fact Nos. 56-59 to the extent they require the Company to include CCR-related ARO expenses in the cost of removal component of its depreciation expense.

DISCUSSION AND CONCLUSIONS

Pursuant to N.C. Gen. Stat. § 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

amount of depreciation and amortization expense, as updated, of $36,026,000, included as an operating revenue deduction in this proceeding under the provisions of the Stipulation, and provided on Company Joint Testimony Exhibit 2 filed on October 12, 2010, is just and reasonable.").

[1] Order Granting Partial Rate Increase, Docket No. W-218, Sub 319 (November 3, 2011).

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 N.C.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, 625, *rev. denied*, 348 N.C. 78, 505 S.E.2d 886 (1998) (*Commission v. NC Gas*).

DENC based its motion, in part, on its post-hearing decision to retire Chesterfield Power Station Units 5 and 6 in 2023. In addition, the Commission notes that the Virginia Clean Economy Act (VCEA) was signed into law on April 11, 2020 and was effective on July 1, 2020. Virginia General Assembly 2020 Session Laws, Ch. 1193; Code of Virginia, §§ 10.1-1308, *et al.* The VCEA, *inter alia*, mandates the retirement of Chesterfield Units 5 and 6 by 2024, unless the Company files a petition with the Virginia State Corporation Commission showing that the retirement would threaten the reliability and security of electric service. This information was included in DENC's Integrated Resource Plan (IRP) filed with the Commission in Docket E-100, Sub 165 on May 1, 2020. DENC's IRP at Sec. 5.2.1, p.83.

The Commission accepts these post-hearing developments as a change of circumstances entitled to significant weight. According to DENC, with the retirements of Chesterfield Units 5 and 6 the requirement in the Rate Order that DENC include CCR-related ARO expenses in the cost of removal component of its depreciation expense would only apply to a small subset of future CCR Costs due to the fact that many of the generating units with outstanding CCR-related AROs have either been retired or have been impaired for financial reporting purposes, and as a result will not be included in future depreciation studies. In addition DENC stated:

> Since the hearing, the Company now plans to early retire the remaining coal units 5 and 6 at the Chesterfield Power Station by 2023, leaving only 4% of the remaining CCR-related ARO pertaining to coal units that will be included in future depreciation studies.

DENC Motion, at 5.

With only 4% of DENC's CCR-related ARO's remaining to be included in depreciation expense, the Commission agrees that this change in circumstances is a sufficient basis for granting DENC's motion under N.C.G.S. § 62-80. As a result, the Commission concludes that it should relieve DENC of the obligation to include its CCR remediation costs in its future depreciation studies. In view of this determination it is unnecessary for the Commission to consider the additional or alternative arguments advanced by DENC in support of this portion of its motion, and the Commission expresses no view on those additional or alternative grounds.

Denial of Return on CCR Costs

DENC contended that the Commission's Findings of Fact Nos. 53-55 and the underlying discussion and conclusions denying the Company a return during the ten-year amortization period for its CCR Costs was arbitrary, inconsistent with past decisions, and unconstitutional. The Company maintained that the Commission has consistently held, including in the three most recent electric utility general rate cases, that for cost recovery, a utility must show that the costs it seeks to recover are (1) known and measurable, (2) reasonable and prudent, and (3) used and useful in the provision of service to customers.[1] DENC stated that in each of the last three electric general rate cases the Commission has held that CCR Costs meet this standard, and that the Company's CCR Costs in the current case meet this standard as well. DENC submitted that the Commission's Rate Order departs from this precedent and classifies the Company's CCR Costs as "deferred operating expenses" not entitled to a return, rather than "property used and useful" that is entitled to a return under N.C. Gen. Stat. § 62-133(b)(1) and (5).

> [T]he Commission determines that just and reasonable rates are achieved, based on the evidence in the record in this proceeding, only when the unamortized balance of CCR Costs are not allowed to earn a return. *Utilities Comm'n v. Duke Power Co.*, 305 N.C. 1, 18, 287 S.E.2d 786, 796 (1982). Accordingly, based on the record as a whole, the Commission concludes that it is appropriate to treat the CCR Costs as deferred operating expenses and not as costs of property used and useful within the meaning and scope of N.C.G.S. § 62-133(b) and to not allow a return on the unamortized balance of the CCR Costs.

Rate Order, at 134.

DENC contended that this contravenes the Commission's findings and conclusions in the Company's 2016 Rate Order where the Commission allowed recovery of CCR Costs, with a return, after determining that "CCR repositories are and have served their purpose ... they have been used and useful for [the Company's] ratepayers." 2016 Rate Order at 61.[2]

Moreover, according to DENC in the following passage the Commission solidified its position on this issue in the 2017 DEP Rate Order by referencing the Company's 2016 rate case when the Public Staff attempted to liken CCR Costs to abandoned nuclear plant costs:

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[1] *See* 2016 Rate Order, Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, Docket No. E-2, Sub 1142 (February 23, 2018) (2017 DEP Rate Order); 2017 DEC Rate Order.

[2] In the 2016 Rate Order, the Commission rejected the Attorney General's recommendation to exclude the unamortized balance of CCR ARO costs from rate base. The Commission stated "the current CCR repositories are and have served their purpose of storing CCRs for many years. In that respect they have been used and useful for [the Company's] ratepayers. However, pursuant to the CCR Final Rule, [the Company] must incur expenses to the existing repositories for environmental remediation . . . Like the existing CCR repositories, these permanent storage repositories will be used and useful for [the Company's] ratepayers." 2016 Rate Order, at 61.

> First and foremost, this case does not involve "abandoned plant" or cancellation costs. Rather, it involves "reasonable and prudent" and "used and useful" expenditures by [DEP], similar to the Commission's determination in the [Company's 2016 Rate Order].

DEP Rate Order, at 191.

DENC stated that the Commission's decision to classify the Company's funding and deferral of CCR Costs as not "used and useful," and ineligible for a return, not only departs from the Commission's three most recent rate case orders, but also runs counter to North Carolina Supreme Court precedent in *Utilities Comm'n v. Virginia Elec. & Power Co.*, 285 N.C. 398, 414-15, 206 S.E.2d 283, 295-96 (1974) (*VEPCO*), in which the Court stated that

> "[w]hile Chapter 62 of the General Statutes makes no reference to working capital, as such, the utility's own funds reasonably invested in such materials and supplies and its cash funds reasonably so held for payment of operating expenses, as they become payable, fall within the meaning of the term 'property used and useful in providing the service,' as used in N.C.G.S. § 62-133(b)(1), and are a proper addition to the rate base on which the utility must be permitted to earn a fair rate of return."

DENC stated that N.C.G.S. § 62-133 does not define the phrase "public utility's property used and useful," and does not restrict "property" to simply generators and power lines, but instead includes all assets necessary to provide electricity to the public. According to DENC, the test is whether the property in question serves the public and was paid by debt or equity investors - "the utility's own funds."

The Company stated that in this case the CCR Costs were funded by the Company's investors and, therefore, the Rate Order incorrectly classified the costs as deferred operating expenses that are not used and useful. The Company pointed to the Commission's DEP and DEC 2017 Rate Orders, and submitted that there the Commission correctly concluded that the funds advanced by the utilities to comply with the CCR rule were "investor-supplied funds, not ratepayer supplied funds and under principles of equity, law and fairness are eligible for a return [on investment]." 2017 DEC Rate Order, at 276.

DENC further stated that the Commission recognized that a failure to allow a return on investment on these investor-supplied funds would deprive investors of the time value of money on these funds, and would ultimately increase the utility's cost of capital. DENC asserted that the Commission's decision to deny a return on the Company's CCR Costs is inconsistent with these precedents, arbitrary, and synonymous with the "equitable sharing" theory that the Commission rejected in the past three rate cases, and nominally rejected in the present case. DENC contended that the Commission reversed course in the Rate Order and is attempting to use "discretion," which the Commission recently held it does not possess, to implement the Public Staff's equitable sharing proposal without finding any specific instance of imprudence related to the Company's CCR Costs. Further, DENC asserted that denying the Company a return during the amortization period also constitutes an unconstitutional taking of capital, as well as a violation of Article I, Section 19 of the North Carolina Constitution because it constitutes a deprivation of the Company's substantive due process and equal protection rights.

DISCUSSION AND CONCLUSIONS

In the Rate Order's preamble to the Commission's discussion of DENC's CCR Costs the Commission stated:

> The testimony and exhibits regarding DENC's CCR Costs are voluminous. The Commission has carefully considered all of the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witness. Rather, the following is a summary of the evidence that is in the record. Likewise, while the Commission has read and fully considered the parties' post-hearing briefs, it has not in this order attempted expressly to discuss every contention advanced or authority cited in the briefs.

Rate Order, at 85-86.

In fact, the Commission considered all of the points now made by DENC in its Motion for Reconsideration. For example, the Commission discussed the facts and holding in *VEPCO*, and expressly rejected DENC's interpretation of the holding. *Id.* at 133. Likewise, the Commission considered its decision in the 2016 DENC Rate Order and expressly stated that because that order was based on a settlement it does not have precedential value with respect to the CCR issues in this case. *Id.* at 122-23.

Further, in *State ex rel. Utilities Comm'n. v. Thornburg*, 325 N.C. 463, 385 S.E.2d 451 (1989) (*Thornburg I*), a general rate case, the Attorney General appealed the Commission's order allowing CP&L to recover as operating expenses the cost of abandoned units 2, 3 and 4 of the Shearon Harris Nuclear Plant. In three prior general rate cases, the Commission had approved the recovery of portions of the costs of the abandoned Shearon Harris units. However, none of those three Commission orders were appealed. In *Thornburg I*, CP&L asserted that the Attorney General was barred from re-litigating the issue of recovery of the abandoned plant costs. The Supreme Court rejected CP&L's argument. The Court held that the Commission's exercise of its ratemaking authority in a general rate case is a legislative rather than a judicial function and, therefore, the Commission's orders in general rate cases are not *res judicata*.

> [I]n fixing rates to be charged by CP&L, the Commission was exercising a function delegated to it by the legislative branch of government. This exercise of the Commission's ratemaking power is not governed by the principles of *res judicata*.[cites omitted]

Id. at 469, 385 S.E.2d at 454. *See also*, *State ex rel. Utilities Com. v. Carolina Power & Light Co.*, 250 N.C. 421, 430, 109 S.E.2d 253, 260 (1959) (the final order of the Commission in a general rate case is not within the doctrine of *stare decisis*.) Of course, the Commission is mindful of the need for regulatory certainty and endeavors to achieve regulatory certainty through compliance with and application of the provisions of the Act to the facts in evidence. Nonetheless, each general rate case must be decided based on the evidence in the record in that proceeding.

DENC further contended that the Commission's exercise of its authority to set just and reasonable rates in this case by disallowing a return on the Company's CCR Costs violated DENC's due process rights and is synonymous with the Public Staff's proposed "equitable sharing" approach. The Commission disagrees and finds that DENC conveniently disregards the Commission's discussion on pages 133-134 of the Rate Order. *See also* N.C.C.S. § 62-133(b)(1) and N.C.G.S. § 62-130(a). Suffice it to say, that the Commission's decisions regarding the ratemaking treatment of DENC's CCR Costs are based on competent, material and substantial evidence of record, as well as a proper application of the Act and case law. Consequently, DENC's contention that the Commission's ratemaking treatment of the CCR Costs— which does not allow DENC to earn a return on the unamortized balance of those costs during the amortization period— is arbitrary, capricious and a violation of its due process rights is without merit.

DENC presented no new evidence, change of circumstances, or misapprehension or disregard of a fact by the Commission. On this issue, the Commission fully considered all of the facts in evidence, applied the various provisions of the Act to those facts in evidence and reached its decisions as to the ratemaking treatment that should be afforded to DENC's CCR Costs in the interest of achieving just and reasonable rates. As a result of the foregoing, the Commission finds and concludes that DENC's Motion on this issue should be denied.

CCR Amortization Period of Ten Years

The Company asserted that the ten-year amortization period for recovery of its CCR Costs violates the due process principles recognized in *Hope* and *Bluefield* and is arbitrary and capricious, unconstitutional, and unsupported by substantial evidence. It stated that in the Commission's Findings of Fact Nos. 53-55, the only basis the Commission provided for the ten-year amortization period is its authority to implement "just and reasonable" rates to reach a division of the CCR Costs between the Company's shareholders and customers that the Commission determined was equitable and that this is contrary to the five-year amortization period found appropriate in the Company's 2016 Rate Order, as well as in DEP's and DEC's 2017 Rate Orders.

In addition, DENC contended that the ten-year amortization period fails to allow the Company a reasonable opportunity to recover its CCR expenses, ensures that DENC will not recover its expenses since it will recover those expenses with less valuable future dollars, and is contrary to the Commission's acknowledgement that "one of the fundamentals of cost-based ratemaking as it has developed in this state is that the full cost of providing utility service should be recovered, as near as may be possible, from rates in effect in the period in which service is provided." Rate Order, at 137. According to DENC, the Company's proposed five-year amortization period would result in less intergenerational inequity than the ten-year amortization period because the costs would be recovered over a shorter period, and a ten-year amortization period will result in "pancaking" of CCR Costs approved in the present case with the recovery of future costs. Finally, DENC asserted that the ten-year amortization period is rooted in the equitable sharing theory that the Commission found to be arbitrary, and appears to, in part, be based on the Company's failure to include CCR Costs in its depreciation expense.

DISCUSSION AND CONCLUSIONS

Similar to its arguments regarding the ratemaking treatment afforded to its CCR Costs, DENC presented no new evidence, change of circumstances, or misapprehension or disregard of a fact by the Commission with respect to the Commission's decision to adopt a ten-year amortization period. For example, DENC asserted that the only basis the Commission provided for the ten-year amortization period is the Commission's authority to implement just and reasonable rates. That is not correct. In the Rate Order the Commission stated, in pertinent part:

> The Commission concludes that based on the evidence in the record, the magnitude and nature of the costs involved and the rate impact to customers as testified to by the Public Staff, a ten-year amortization period strikes the more appropriate and fairer balance. This decision is consistent with the Commission's historical treatment of major plant cancellations. *See* Anna/Surry Order at 355 (noting that [t]his Commission has consistently used a write-off period of 10 or fewer years for all major plant cancellations).

Id. at 135. Further, as stated previously the Commission rejected DENC's contention that the 2016 DENC Rate Order was precedent in the present case.

The Commission fully considered all of the facts in evidence and the applicable precedents in reaching its decision to set the amortization period for CCR Costs at ten years. The Commission's decision was based on substantial evidence, is not arbitrary or capricious, and does not violate DENC's due process rights. As a result, the Commission finds and concludes that DENC's Motion for Reconsideration on this issue should be denied.

Finally, the Commission confirms that it intended to authorize DENC to defer its CCR Costs incurred after June 30, 2019, for consideration in the Company's next general rate case. Further, as in the Rate Order, the Commission's decision herein does not address the issue of return on CCR Costs incurred after June 30, 2019.

PUBLIC STAFF'S MOTION

> (1) The Public Staff requested clarification and/or reconsideration of the requirement that DENC include CCR-related ARO expenses in the cost of removal component of its depreciation expense. Ultimately, the Public Staff requested the Commission to address three questions: Does the Commission intend the depreciation method to be used only for CCR Costs associated with ash produced in the future, and thus inherently related to future operations? If so, does the Commission intend for future CCR expenditures associated with past operations to be recovered through the method approved in this proceeding for historic CCR expenditures?

> (2) Does the Commission instead intend the full amount of future CCR expenditures to be recovered through the depreciation method going forward, whether or not related to ash produced in the future?
>
> (3) Does the Commission intend that recovery of CCR Costs through revised depreciation rates include a sharing or balancing of those costs between ratepayers and shareholders?

DISCUSSION AND CONCLUSIONS

The Commission's decision herein on the recording of future depreciation expense with respect to CCR Costs renders the Public Staff's request for reconsideration or clarification moot. On this record the Commission declines to issue an advisory ruling with respect to the questions presented by the Public Staff's motion.

IMPLEMENTATION OF NEW RATES

On October 11, 2019, DENC filed motions requesting Commission approvals under N.C. Gen. Stat. § 62-135 of the proposed customer notice implementing temporary rates on and after November 1, 2019, and the Company's proposed financial undertaking to secure its obligation to refund any overcollection, plus interest, if its temporary rates resulted in charges greater than the rates ultimately approved by the Commission.

On October 18, 2019, the Commission issued an Order approving DENC's proposed customer notice implementing temporary rates, and an Order approving DENC's financial undertaking to secure its potential refund obligation.

The following Ordering Paragraphs were included in the Rate Order:

> 10. That as soon as practicable following the issuance of this Order DENC shall file with the Commission the annual revenue requirement and accompanying rate schedules and terms and conditions that are consistent with the findings and conclusions of this Order and the Public Staff Stipulation, with the exception of Section VII.A. The Company shall work with the Public Staff to verify the accuracy of the filing. Further, DENC shall file schedules summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding;
>
> 11. That DENC is hereby authorized to adjust its rates and charges in accordance with the findings in this Order effective for service rendered on and after the following day after the Commission issues an Order accepting the calculations required by Ordering Paragraph No. 10;

Rate Order, at 149-50.

DENC has not yet complied with the directives of Ordering Paragraphs Nos. 10 and 11 of the Rate Order. The Commission finds good cause to require that within ten days of the date of this Order DENC shall file the necessary documents to comply with the above Ordering Paragraphs, as more specifically set forth in the Ordering Paragraphs below.

IT IS, THEREFORE, ORDERED as follows:

1. That DENC shall be, and is hereby, authorized to defer its CCR Costs incurred after June 30, 2019, for consideration in the Company's next general rate case;

2. That DENC's Motion for Reconsideration and Clarification shall be, and is hereby, granted as to the inclusion of DENC's CCR Costs in its future depreciation studies, and such costs shall not be required to be included in DENC's future depreciation studies;

3. That the Public Staff's Motion for Clarification is dismissed as moot;

4 That DENC's Motion for Reconsideration and Clarification shall be, and is hereby, denied as to the Rate Order's provisions relating to the ratemaking treatment afforded the CCR Costs and the amortization period for CCR Costs;

5. That within ten days of the date of this Order DENC shall file with the Commission the annual revenue requirement and accompanying rate schedules and terms and conditions that are consistent with the findings and conclusions of the Rate Order and the Public Staff Stipulation, with the exception of Section VII.A. The Company shall work with the Public Staff to verify the accuracy of the filing. Further, DENC shall file schedules summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in the Rate Order;

6. That along with the filing required by Ordering Paragraph No. 6 above, DENC shall file statements and workpapers demonstrating the difference in the revenue received by DENC under its temporary rates and the revenue that DENC would have received from November 1, 2019 through July 31, 2020, under the revenue requirement and accompanying rate schedules filed in response to Ordering Paragraph No. 4 above; and

7. That along with the filing required by Ordering Paragraph No. 7 above, DENC shall file statements and workpapers setting forth its proposed plan for refunding to its customers, effective for service beginning August 1, 2020, the difference in the revenue received by DENC under its temporary rates and the revenue that DENC would have received from November 1, 2019 through June 30, 2020, under the Rate Order, plus interest.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of July, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

Commissioners Kimberly W. Duffley, Jeffrey A. Hughes and Floyd B. McKissick, Jr., did not participate in this decision.

DOCKET NO. E-7, SUB 1026

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	)	ORDER APPROVING RIDERS
North Carolina	)	

BY THE COMMISSION: On May 1, 2020, Duke Energy Carolinas, LLC (DEC or the Company), filed a proposed Bulk Power Marketing (BPM) True-up Rider and a BPM Prospective Rider, to be effective for the period July 1, 2020, through June 30, 2021.[1] The purpose of the BPM Prospective Rider and the BPM True-up Rider is to flow back to DEC's North Carolina retail customers their jurisdictionally allocated share of 90% of the Company's BPM Net Revenues and 100% of its Non-Firm Point-to-Point Transmission (NFPTP) Revenues, on a prospective basis and subsequently on a trued-up basis. As reflected in the May 1 filing, the proposed BPM True-up Rider consists of a rate decrement of (0.0049) cents per kWh, based on a comparison of DEC's actual BPM Net Revenues and NFPTP Revenues earned in calendar year 2019 with the amounts credited to North Carolina retail customers during 2019 for those two categories. In the filing, DEC also proposed a BPM Prospective Rider consisting of a rate decrement of (0.0129) cents per kWh.

The proposed decrement BPM True-up Rider of (0.0049) cents per kWh, if approved, will replace the existing decrement BPM True-up Rider of (0.0040) cents per kWh approved by the Commission in its Order issued June 25, 2019, in Docket No. E-7, Sub 1026. The proposed decrement BPM Prospective Rider of (0.0129) cents per kWh, if approved, will replace the current BPM Prospective Rider decrement of (0.0122) cents per kWh included in base rates. The sum of the proposed BPM Prospective Rider and BPM True-up Rider, including the regulatory fee, is a rate decrement of (0.0178) cents per kWh, which is a further decrement of 0.0016 cents per kWh from the existing combined rider decrement of (0.0162) cents per kWh, including the regulatory fee, approved in 2019.

A BPM/NFPTP Rider was first approved by the Commission on December 20, 2007, in DEC's general rate case in Docket No. E-7, Sub 828, and the Commission has continued to approve the BPM/NFPTP mechanism in subsequent general rate cases. Under the mechanism, 90% of the allocated North Carolina retail portion of DEC's BPM Net Revenues and 100% of the similarly allocated NFPTP Revenues are flowed through to the benefit of the Company's North Carolina retail customers. The annual rider was established to true up the difference between the actual amounts calculated to be flowed through pursuant to those allocations and percentages and the amounts included in base rates for that purpose, as calculated for the then most recent calendar year.

[1] Except as otherwise indicated, all proposed rates exclude the North Carolina regulatory fee.

ELECTRIC – RATE INCREASE

In its 2013 general rate case order in Docket No. E-7, Sub 1026 (Sub 1026 Order), the Commission reaffirmed the 90% and 100% allocations, and also reaffirmed that the true-up process would continue. Additionally, the Sub 1026 Order directed that (1) the decrement amounts recovered in base rates would be prospectively implemented in the form of a continuing decrement rider (BPM Prospective Rider), which would be subject to modification in each annual rider adjustment proceeding; (2) the annual true-up for the most recent calendar year (the BPM True-up Rider) would continue; and (3) the return on any over- or under-recovery included as part of the BPM True-up Rider would be calculated using a rate of return equal to 50% of the after-tax rate of return then approved by the Commission. The BPM Prospective Rider is calculated annually based on projected BPM and NFPTP transmission revenues and expected kWh sales.

According to DEC's May 1, 2020 filing, the proposed BPM True-up Rider is calculated by dividing the North Carolina retail BPM and NFPTP Revenues Adjustment of $(2,824,431) (the difference between 2019 actual BPM and NFPTP revenues and the collected 2019 BPM Prospective Rider decrements, plus a return on deferred revenues) by projected North Carolina retail sales of 57,069,434,000 kWh for the period July 2020 –June 2021. The resulting BPM True-up Rider amount is a rate decrement of (0.0049) cents per kWh. The proposed BPM Prospective Rider is calculated by dividing the North Carolina retail BPM and NFPTP forecasted calendar year 2020 revenue to share of $(7,298,000) by projected North Carolina retail calendar year 2020 sales of 56,541,206,000 kWh.

This matter was presented at the Commission's Regular Staff Conference on June 15, 2020. The Public Staff stated that it had reviewed DEC's calculation of the proposed riders, including the supporting workpapers submitted with the filings and information provided by the Company in response to Public Staff data requests, and had concluded that the proposed riders are reasonable. Therefore, the Public Staff recommended that DEC's proposed riders be approved. The Public Staff also indicated that including the North Carolina regulatory fee does not cause a change in the Riders in this case.

Based on its review of DEC's filing and the recommendation of the Public Staff, the Commission concludes that the proposed riders are reasonable and should be approved, effective on July 1, 2020.

IT IS, THEREFORE, ORDERED, as follows:

1. That the following riders for Bulk Power Marketing Net Revenues and Non-Firm Point-to-Point Transmission Revenues proposed by DEC in its filing of May 1, 2020, are approved effective during the period July 1, 2020, through June 30, 2021:

> (1) a BPM True-up Rider, consisting of a rate decrement of (0.0049) cents per kWh, including the regulatory fee; and
>
> (2) a BPM Prospective Rider, consisting of a rate decrement of (0.0129) cents per kWh, including the regulatory fee.

2. That 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 15th day of June, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Joann R. Snyder, Deputy Clerk

DOCKET NO. E-7, SUB 1146

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Carolinas, LLC,	)	ORDER EXTENDING ADVANCED
for Adjustment of Rates and Charges	)	RATE DESIGN PILOT PROGRAMS
Applicable to Electric Utility Service in North	)	AND REQUIRING INTERIM AND
Carolina	)	FINAL REPORTS

BY THE COMMISSION: On July 2, 2019, the Commission issued an Order Approving Pilots that approved Duke Energy Carolinas, LLC's (DEC's), nine proposed advanced rate design pilot programs, with modifications proposed by the Public Staff and accepted by DEC (Pilots). The Pilots required a one-year commitment by participating customers, and were approved for a one-year period through September 30, 2020.

On September 16, 2020, DEC filed a letter requesting that the Pilots be extended until July 1, 2021. In summary, DEC stated that it has experienced good participation by customers in the Pilots, with most participants reporting they are satisfied or very satisfied with the Pilots. Additionally, DEC stated that a majority of participants saved on their bills based upon a mid-pilot structural comparison of the rates under the Pilots and the participants' previous rates. Moreover, DEC stated that it engaged a third party to evaluate the Pilots, and DEC intends to launch final designs by July 1, 2021, subject to Commission approval. DEC proposed that between October 1, 2020 and July 1, 2021, customers in the Pilots be allowed to continue participating. DEC further proposed that it send participating customers another structural bill comparison in fourth quarter 2020 showing how they did under the Pilots, informing customers that the Pilots have been extended to July 1, 2021, and informing customers that they have the option to end their participation in the Pilots during the extended period. Finally, DEC stated that it discussed its request for an extension with the Public Staff, and it is DEC's understanding that the Public Staff supports the requested extension of the Pilots.

Based on the foregoing and the record, the Commission finds good cause to grant DEC's request to extend the Pilots until July 1, 2021. In addition, the Commission finds good cause to require DEC to file an interim progress report on or before January 1, 2021, summarizing progress and key interim findings, and a final report on or before August 1, 2021, detailing customer participation in the Pilots, cumulative statistics on the structural bill comparisons of participants, information about the peak shaving attributes of the Pilots, and a discussion of lessons learned from the Pilots. Finally, prior to preparing the interim and final reports DEC shall consult with the Public Staff and DEC's third party consultant to identify additional information to be included in the reports.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of October, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

DOCKET NO. E-35, SUB 51

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Western Carolina University	)	ORDER GRANTING
for an Adjustment of Rates and Charges	)	GENERAL RATE INCREASE
for Electric Service in North Carolina	)	AND ACCEPTING STIPULATION

BY THE COMMISSION: On March 9, 2020, Western Carolina University (WCU) filed an application with the Commission requesting authority to adjust its rates for retail electric service in its service area in Jackson County, North Carolina. WCU filed an amended application on June 24, 2020. WCU operates an off-campus electric distribution system that serves approximately 3,170 residential customers and 230 commercial customers. The present rates have been in effect since 2016, with annual purchased power adjustments. WCU's application was verified by Mike Byers, Vice-Chancellor for Administration and Finance for WCU, and was accompanied by the direct testimony of William R. O'Donnell, CPA.

On April 6, 2020, the Commission issued an order declaring this proceeding to be a general rate case pursuant to N.C. Gen. Stat. § 62-137 and suspending the proposed rate increases for up to 270 days pursuant to N.C.G.S. § 62-134. In this Order, the Commission also provided that an order scheduling hearings and requiring customer notice would be issued at a later date.

On July 17, 2020, because of restrictions on mass gatherings imposed by the Governor to address the spread of the coronavirus, the Commission issued an order scheduling a remote hearing in this proceeding to occur on Thursday, September 10, 2020, for the purpose of receiving the testimony of public witnesses and resuming on Monday, September 14, 2020, for the purpose of receiving the testimony of expert witnesses. This Order also provided that members of the public who wish to testify at the remote hearing on September 10, 2020, must register with the Public Staff prior to 4:00 p.m. on September 4, 2020 and further provided that the Commission would issue an order setting forth procedures for a remote expert witness hearing or confirming that the expert witness hearing will be held in the Commission Hearing Room. Finally, that Order established the test period to be used in this proceeding, required WCU to provide notice of its pending application and established August 10, 2020, as the deadline for the filing of petitions to intervene.

On August 6, 2020, WCU filed a statement consenting to conducting the expert witness hearing remotely.

On August 10, 2020, the Public Staff filed a statement consenting to conducting the expert witness hearing remotely. As of August 10, 2020, the deadline for the filing of petitions to intervene, no persons had sought to intervene in this proceeding, although the Public Staff is recognized as a party to this proceeding in accordance with N.C.G.S. § 62-15(d).

On August 14, 2020, the Commission issued an order confirming that the expert witness hearing in this proceeding would be held by remote means and adopting certain procedural requirements for the remote proceeding.

On August 21, 2020, the Public Staff filed the testimony and exhibits of its witnesses Scott J. Saillor, Evan D. Lawrence, Benjamin P. Lozier, and Sonja R. Johnson.

On August 27, 2020, the Public Staff filed a notice of settlement informing the Commission that the Public Staff and WCU have reached a settlement in this proceeding. The Public Staff further stated that a detailed settlement agreement would be filed at a later date.

On September 8, 2020, WCU filed an Affidavit of Publication demonstrating that notice of the proposed rate increase had been provided to its customers consistent as required by the Commission.

On September 9, 2020, the Commission issued an order canceling the public witness hearing scheduled for Thursday, September 10, 2020.

Also on September 9, 2020, the Public Staff filed a stipulation of settlement, detailing the Public Staff and WCU's agreements in settlement of this proceeding (Stipulation). In summary, the Stipulation provides that the parties agree to certain adjustments to WCU's requested revenue requirement to produce a $612,749 increase in WCU's revenue requirement, as recommended in the testimony and exhibits of Public Staff witness Sonja R. Johnson. The Stipulation further details the parties' agreements regarding revenues per customer class and the appropriate treatment of the purchased power adjustment rider (PPA rider), which was most recently approved in Docket No. E-35, Sub 50. In addition, the Stipulation provides that the Public Staff and WCU agree to the admission of the testimony and exhibits filed in this docket and to waive the right to cross-examine all witnesses. Finally, the Stipulation provides that the Public Staff and WCU agree that the agreements in the Stipulation resulted from extensive negotiation and compromise, including the debt calculation methodology used, should not be given precedential effcet before the Commission or any other regulatory body.

In addition, on September 9, 2020, the Public Staff filed a motion requesting that the expert witness hearing scheduled for September 14, 2020 be canceled. In support of its motion, the Public Staff states that the parties have reached a settlement of all disputed issues in this case, as reflected in the Stipulation. The Public Staff further states that it contacted counsel for WCU and that WCU has no objection to canceling the expert witness hearing.

On September 11, 2020, the Commission issued an order canceling the expert witness hearing scheduled for September 14, 2020, admitting into the record the testimony and exhibits filed in this docket, and allowing the parties to file proposed orders and briefs on or before October 12, 2020.

Based upon the foregoing and the entire record herein, the Commission makes the following

FINDINGS OF FACT

1. WCU is a State-supported institution of higher learning which owns and operates an electric distribution system. Although not a public utility, WCU is properly subject to the jurisdiction of the Commission pursuant to N.C.G.S. § 116-35 with respect to the justness and reasonableness of the rates charged and services rendered to its retail electric customers in the Cullowhee area, Jackson County, North Carolina.

2. WCU does not generate its own electricity but buys power wholesale from Duke Energy Carolinas, LLC, at rates approved by the Federal Energy Regulatory Commission (FERC).

3. WCU's last general rate case order was issued on May 25, 2016.

4. The test year for purposes of establishing rates in this docket is the 12-month period ended June 30, 2019.

5. WCU requested an increase in its electric rates that would produce $625,500 in additional annual revenues.

6. WCU is providing adequate electric service to its customers in its service area.

7. WCU gave sufficient and proper notice to its customers of the proposed increase in rates.

8. The Parties filed the Stipulation on September 9, 2020, resolving all disputed issues in this docket.

9. WCU had plant in service, net of cost-free capital, of $6,937,255 as of the end of the test year.

10. The reasonable balance of accumulated depreciation as of the end of the test year was $(3,842,817).

11. The reasonable balance of supplies and material inventory as of the end of the test year was $313,580.

12. The reasonable balance of working capital as of the end of the test year was $364,903.

13. The reasonable balance of customer deposits as of the end of the test year was $(224,671).

14. WCU's reasonable original cost rate base for purposes of this proceeding, consisting of plant in service (net of cost-free capital), supplies and material inventory, and working capital, net of accumulated depreciation and customer deposits, is $3,548,251.

15. The pro forma test year amount of operation and maintenance expenses under present rates reasonable and appropriate for purposes of this proceeding is $4,714,589.

16. The pro forma test year amount of depreciation expense reasonable and appropriate for purposes of this proceeding is $196,026.

17. WCU's pro forma test year amount of Unrelated Business Income Tax expense reasonable and appropriate for purposes of this proceeding is $(93,153).

18. WCU's total pro forma test year operating revenue deductions under present rates for purposes of this proceeding are $4,817,462.

19. WCU's total pro forma test year operating revenues under present rates for purposes of this proceeding are $4,569,742.

20. The Parties agreed on a 6.32% overall rate of return. The stipulated overall rate of return reflects a hypothetical capital structure for WCU consisting of 50% debt and 50% equity.

21. The reasonable and appropriate cost of debt for purposes of this proceeding is 3.64% and the reasonable and appropriate cost of equity for purposes of this proceeding is 9.00%.

22. The Parties agreed that WCU is entitled to rates and charges that will produce $612,749 in additional annual revenues.

23. The Parties agreed that WCU's revenues from its retail operations for the twelve months ended June 30, 2019, by customer class under present base rates and as increased to meet the agreed-upon revenue increase requirement, will be as follows:

ELECTRIC – RATE INCREASE

Customer Class	Present Operating Revenues	Proposed Revenue Increase	Proposed Operating Revenues
Residential	$ 3,461,647	$ 469,836	$ 3,931,483
Commercial	$ 1,070,065	$ 120,095	$ 1,190,159
Lighting	$ 38,031	$ 22,818	$ 60,849
Rate Schedule Total	$ 4,569,742	$ 612,749	$ 5,182,491

24. With regard to the cost of purchased power and the Purchased Power Adjustment (PPA) rider, the Parties agreed that it is appropriate and reasonable to continue the current procedure and method used to determine the annual PPA rider, which was first approved in Docket Nos. E-35, Sub 17 and Sub 19. The Parties have further agreed that the base purchased power cost factor reflected in the agreed-to proposed base revenues in this proceeding and established for use in future PPA Rider proceedings, coincident with the effective date of rates approved in this proceeding, is $0.07759 per kilowatt-hour (kWh). The Parties have further agreed that, coincident with the effective date of rates approved in this proceeding, the current "Factor for estimated purchased power costs for the period February 2020 through January 2021" of $0.00074 per kWh, approved as a component of the Schedule "CP" Purchased Power Cost Rider in Docket No. E-35, Sub 50, will be reset to $0.00000 per kWh.

25. The Parties acknowledged that the Stipulation resulted from extensive negotiations and compromise. Thus, the agreements reached do not necessarily reflect the respective Parties' beliefs as to the proper treatment or level of the matters cited. Except as needed to carry out the terms of the Commission's order based on the Stipulation, the Parties agreed that none of the positions, treatments, figures or other matters reflected in the Stipulation shall have any precedential value, nor shall they otherwise be used in any subsequent proceedings before this Commission or any other regulatory body as proof of the matter in issue.

26. The Stipulation is the product of give-and-take in settlement negotiations, and the rates agreed to in the Stipulation are just and reasonable and serve the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-5

The evidence supporting these findings of fact is found in WCU's verified application; the affidavits, testimony, and exhibits of the Parties' witnesses; the Stipulation; and the entire record herein. These findings of fact are essentially informational, jurisdictional, and procedural, and are not in dispute.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is found in the affidavits, testimony, and exhibits of the Parties' witnesses and in the entire record in this proceeding. No customers or other non-expert public witnesses submitted any comments regarding the quality of service by WCU, and no WCU customers expressed an interest in testifying at the public witness hearing in this proceeding. Based upon the foregoing and the entire record herein, the Commission finds that WCU is providing adequate electric service to its customers in its service area.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is found in the affidavits filed by WCU on September 8, 2020, indicating that customer notice had been provided in accordance with the Commission's Order. This finding is uncontested. Based upon the foregoing, the Commission finds that WCU gave sufficient and proper notice to its customers of the proposed increase in rates.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-26

The evidence supporting these findings of fact is found in WCU's verified application; the affidavits, testimony, and exhibits of the Parties; the Stipulation between the Parties; and the entire record in this proceeding.

On September 9, 2020, the Parties filed a Stipulation in which they agreed to and recommended an increase in revenues. The amount of the agreed-upon increase was $612,749. The Stipulation recites that the agreements embodied in the Stipulation resulted from extensive negotiations and compromise between WCU and the Public Staff, and, thus, the agreements reached do not necessarily reflect the respective Parties' beliefs as to the proper treatment or level of the matters cited. Except as needed to carry out the terms of the Commission's order based on the Stipulation, the Parties agreed that none of the positions, treatments, figures or other matters reflected in the Stipulation shall have any precedential value, nor shall they otherwise be used in any subsequent proceedings before this Commission or any other regulatory body as proof of the matter in issue.

The Commission has carefully considered the Stipulation and the entire record herein. Based on this review, the Commission finds that the Stipulation is the product of give-and-take in settlement negotiations. The Commission further finds that the rates agreed to in the Stipulation are just and reasonable and serve the public interest. Therefore, the Commission concludes that the Stipulation between WCU and the Public Staff is reasonable and appropriate for purposes of this proceeding and should be accepted, and that the rates agreed to in the Stipulation should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That WCU is authorized to adjust its rates and charges and fees to increase its annual gross revenues by $612,749, effective for bills rendered on or after December 1, 2020;

2. That WCU shall file tariff sheets within ten days from the date of this Order reflecting the rates and fees designed to produce the increase in revenues as approved herein; and

3. That WCU and the Public Staff shall jointly prepare and within ten days of the date of this Order file a proposed customer notice addressing the rate increase approved herein, effective for bills rendered on or after December 1, 2020.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of October, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Joann R. Snyder, Deputy Clerk

DOCKET NO. E-22, SUB 577

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Virginia Electric and Power Company d/b/a Dominion Energy North Carolina for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to N.C. Gen. Stat. § 62-133.9 and Commission Rule R8-69	))))))	ORDER APPROVING DSM/EE RIDER AND REQUIRING FILING OF PROPOSED CUSTOMER NOTICE

HEARD: Tuesday, November 12, 2019, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Chair Charlotte A. Mitchell, Commissioner Lyons Gray and Commissioner Daniel G. Clodfelter

APPEARANCES:

For Dominion Energy North Carolina:

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

Carolina Industrial Group for Fair Utility Rates I (CIGFUR):

Warren Hicks, 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: North Carolina 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 13, 2019, 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 (PPI).

__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 January 10, 2019, in Docket No. E-22, Sub 556 (2019 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.

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), which implemented the change to the Portfolio Performance Incentive (PPI).[1] 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.

Pertinent Proceedings in Related Dockets

On July 12, 2019, DENC filed applications in Docket Nos. E-22, Subs 567-574 requesting approval of the following programs as new DSM/EE programs: Residential Home Energy Assessment, Residential Efficient Products Marketplace, Residential Appliance Recycling, Non-residential Window Film, Non-Residential Small Manufacturing, Non-Residential Office, Non-Residential Lighting Systems & Controls, and Non-Residential Heating and Cooling Efficiency. On October 22, 2019, the Public Staff filed a letter and proposed order recommending the Commission approve the proposed programs, and cancel the North Carolina-only versions of the Non-Residential Lighting Systems & Controls Program, and the Non-Residential Heating and Cooling Efficiency Program upon implementation of the system-wide versions of those programs.

On November 13, 2019, the Commission issued an Order Approving Demand-Side Management and Energy Efficiency Programs approving the above listed programs, and cancelling the North Carolina-only programs upon implementation of the system-wide version of the programs.

[1] For the levelization run-out of the trued-up Program Performance Incentive for measures installed or implemented prior to 2017, the Company carried forward those incentives as calculated pursuant to the Mechanism and Revised Mechanism. The program cost, common costs, and net lost revenue utility incentive revenue requirements are also calculated in the same manner under the 2017 Mechanism as they were under the Mechanism and Revised Mechanism.

Proceedings in the Present Docket

On August 13, 2019, 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, Robert E. Miller, 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 4, 2019, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. Pursuant to the Order, the Commission established deadlines for the filing of petitions to intervene, intervenor testimony and exhibits, and Company rebuttal testimony and exhibits, and also required DENC to publish a customer notice. The Commission scheduled a hearing to be held on Tuesday, November 12, 2019.

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 6, 2019, Carolina Industrial Group for Fair Utility Rates I (CIGFUR) filed a Petition to Intervene.

On September 17, 2019, the Commission granted CIGFUR's Petition to Intervene.

On October 22, 2019, the Public Staff filed the testimony of David M. Williamson and Michael C. Maness.

On October 24, 2019, DENC filed an Affidavit of Publication indicating that it had provided notice in newspapers of general circulation.

On October 29, 2019, the Public Staff filed a corrected page 7 of the testimony of David M. Williamson.

On October 31, 2019, DENC filed a letter in lieu of rebuttal testimony accepting the recommendation of the Public Staff.

On November 4, 2019, DENC and the Public Staff filed a Joint Motion to Excuse Witnesses from appearing at the November 12, 2019, expert witness hearing, stating that they had reached agreement on all issues in this docket and had agreed to waive cross-examination of each other's witnesses.

On November 6, 2019, the Joint Motion to Excuse Witnesses was granted.

On November 12, 2019, the Public Staff filed a letter providing the Commission with the final results of the Public Staff's review of the costs of the portfolio of DSM/EE programs incurred during the test year by the Company and recommending Commission approval of Company's proposed Rider C and Rider CE bill rates. On that same date, the Commission held the expert witness and public witness hearing as scheduled. No public witnesses appeared at the hearing.

On December 12, 2019, 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. 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, 2018 through December 31, 2018.

4. The rate period for purposes of this proceeding is the 12-month period of February 1, 2020 through January 31, 2021.

5. DENC has requested rate period recovery of costs and utility incentives (NLR and PPI) related to the following approved DSM/EE Programs: (a) Phase I Air Conditioner Cycling Program; (b) 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; (f) the Phase VI Non-Residential Prescriptive Program, and (g) the Phase VII DSM/EE programs: Residential Appliance Recycling Program, Residential Efficient Products Marketplace Program, Residential Home Energy Assessment Program, Non-Residential Lighting Systems & Controls Program, Non-Residential Heating and Cooling Efficiency Program, Non-Residential Window Film Program, Non-Residential Small Manufacturing Program, and Non-Residential Office Program.[1]

[1] As noted above, the proposed Phase VII programs were approved by the Commission on November 13, 2019.

6. 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 Lighting Program; Commercial HVAC Program; Commercial Lighting Program; Residential Heat Pump Upgrade Program; Residential Home Energy Check Up Program; Non-residential Duct Testing and Sealing Program; Non-residential Energy Audit Program; Non-residential Heating & Cooling Efficiency Program; Non-residential Lighting Systems and Controls Program; Non-residential Window Film Program; Commercial Small Business Improvement Program; North Carolina-only Residential LED Lighting Program; Residential Income and Age Qualifying Home Improvement Program; and the Non-residential Prescriptive Program.

7. 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.

8. 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.

9. DENC's proposed North Carolina retail DSM/EE Rider C rate period revenue requirement of $3,470,280, consisting of DSM/EE program costs, common costs, and a PPI, is reasonable.

10. 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, as reduced by Rider C revenues collected for the test year, is $464,010.

11. Rider C as proposed in the Application is reasonable and appropriate, and consists of the following increment customer class billing factors: Residential – 0.109 ¢/kWh; Small General Service and Public Authority – 0.158 ¢/kWh; Large General Service – 0.097 ¢/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, 2020.

12. 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 – 0.016 ¢/kWh; Small General Service and Public Authority – 0.018 ¢/kWh; Large General Service – 0.011 ¢/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, 2020.

13. DENC requested the recovery of NLR in the amount of $646,489 and PPI in the amount of $324,148 for the test period, and a projected PPI of $365,331, 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.

14. The jurisdictional and customer class cost allocations for Rider C and Rider CE included in the testimony and exhibits of Company witness Miller are acceptable for purposes of this proceeding and are consistent with the 2017 Mechanism.

15. 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.

16. 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 2018 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 FINDING OF FACT NO. 4

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 period as that in which the fuel rider established under Rule R8-55 is in effect, in years prior to 2018 the Company proposed Rider C rates to be effective for a calendar year rate period. This was consistent with the rate period previously used for fuel riders under Rule R8-55. Based on discussions with the Public Staff following the conclusion of the Company's 2017 rider proceedings, beginning in 2018 DENC proposed updated Riders C and CE to be effective for a February 1 through January 31 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 requested this adjustment in order to extend the time for the Commission to issue orders in the Company's three annual rider proceedings, to allow the Company additional time to finalize rates and customer notices, and to allow reasonable time for Public Staff review, prior to the updated annual riders' effective date. The witnesses stated that the Company intends to continue to use a February 1 through January 31 rate period in future rider cases.

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, 2020.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-8

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) Phase I Air Conditioner Cycling Program; (b) 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; (f) the Phase VI Non-Residential Prescriptive Program, and (g) the Phase VII DSM/EE programs: Residential Appliance Recycling Program, Residential Efficient Products Marketplace Program, Residential Home Energy Assessment Program, Non-Residential Lighting Systems & Controls Program, Non-Residential Heating and Cooling Efficiency Program, Non-Residential Window Film Program, Non-Residential Small Manufacturing Program, and Non-Residential Office 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 III, Phase IV, Phase V, Phase VI Programs, and the Residential Retail LED Lighting Program during the January 1, 2018 to December 31, 2018, 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 2020 to the proposed February 1, 2020 – January 31, 2021 rate period. As stated in her testimony, 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, with the exception of the AC Cycling Program and 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 DSM/EE cost recovery riders since 2014. 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 based on 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. 9-14

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, Miller, 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 Miller 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 Miller 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 Miller, 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 the 9.90% rate of return on common equity based on the rate of return on common equity that was approved in the Company's then 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, received from the Company's accounting department, with the test period costs, NLR, and PPI, as provided by witness Bates and as allocated jurisdictionally by witness Miller. 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, 2018, 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, and 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 Public Staff intends to have further discussions with the Company regarding the appropriate input to use in the determination of avoided capacity benefits. Witness Maness recommended the final determination of Vintage 2020 avoided capacity benefits for the purpose of calculating PPI should be delayed until next year's rider proceeding. In its October 31, 2019 Letter in Lieu of Rebuttal Testimony, the Company did not oppose the Public Staff's recommendation to delay the final determination of the Vintage 2020 avoided capacity benefits for the purpose of calculating PPI.

On Company Exhibit AJM-1, Schedule 1, page 1, witness Moore calculated DENC's requested North Carolina retail rate period (February 1, 2020, through January 31, 2021) revenue requirement (for Rider C) as follows:

1.	Operating Expense	$2,970,724
2.	Capital Cost	$134,225
3.	NLR	$0
4.	PPI	$365,331
5.	Total	$3,470,280

On Company Exhibit AJM-1, Schedule 2 (and as also reflected in the testimony of Public Staff witness Maness), witness Moore calculated DENC's requested North Carolina retail test period DSM/EE EMF (January 1, 2018, through December 31, 2018) revenue requirement (for Rider CE) as follows:

Operating expenses	$2,880,600
Capital costs (depr, rate base, prop. taxes)	$134,634
NLR	$646,489
PPI	$324,148
Test period Rider C revenues	($3,495,984)
Net revenue requirement subtotal	$489,887
Carrying costs	($25,877)
Total Rider CE revenue requirement	$464,010

Company witness Miller, in Exhibit REM-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	$1,780,344	$268,847
SGS Co & Muni	$1,228,533	$141,877
LGS	$461,403	$53,285
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, 2020:

CUSTOMER CLASS	RIDER C RATE (cents/kWh)	RIDER CE RATE (cents/kWh)
Residential	0.109	0.016
Small General Service & Public Authority	0.158	0.018
Large General Service	0.097	0.011
6VP	0	0
NS	0	0
Outdoor Lighting	0	0
Traffic Lighting	0	0

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 direct filing, 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. Finaly, the Commission accepts as appropriate the agreement of the Company and Public Staff to postpone until DENC's 2020 DSM/EE rider proceeding the final determination of the Vintage 2020 avoided capacity benefits for the purpose of calculating PPI.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

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 2018 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. He further stated that the EC department relies heavily on online tools for general education; their web pages received around 71,000 visits in the test period, and the web pages for the implementation contractor, Honeywell, also received over 177,000 visits. Witness Bates stated that the Company is continually growing social media presence, gaining over 91,000 and 61,000 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 FINDINGS OF FACT NOS. 16-17

The evidence for these findings of fact is contained in the direct testimony of Company witnesses Kesler, the EM&V report filed by DENC on May 1, 2018 in Docket No. E-22, Sub 545, the schedules of Company witness Kesler, and the testimony of Public Staff witness Williamson.

DENC witness Kesler provided and testified to the Company's projected EM&V costs during Calendar Year 2020 and actual EM&V costs during the 2018 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 2019 EM&V report for calendar year 2018 with the assistance of GDS Associates. He stated that DENC and its EM&V consultant implemented certain changes and corrections to the Vintage 2017 savings for several programs as recommended by the Public Staff and accepted by the Commission in the previous cost recovery proceeding. He further testified 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 566 proceeding have been incorporated into the Vintage 2017 savings as identified in the 2018 EM&V Report. Witness Williamson did not recommend any further adjustments to the 2019 EM&V Report based on his review.

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, 2020, consists of the following customer class billing factor increments (including Regulatory Fee): Residential – 0.109 ¢/kWh; Small General Service and Public Authority – 0.158 ¢/kWh; Large General Service – 0.097 ¢/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, 2020, consists of the following customer class decrement billing factors (including Regulatory Fee): Residential – 0.016 ¢/kWh; Small General Service and Public Authority – 0.018 ¢/kWh; Large General Service – 0.011 ¢/kWh; and no decrement for 6VP, NS, Outdoor Lighting and Traffic Lighting.

3. 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 578 and 579, and the Company shall file such notice for Commission approval as soon as practicable, but not later than five working days after the Commission issues the last of its orders in the above-referenced dockets.

4. That DENC shall file appropriate rate schedules and riders with the Commission to implement the provisions of this Order as soon as practicable.

5. 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 17th day of January, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberly A. Campbell, Chief Clerk

DOCKET NO. E-22, SUB 578

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 REPS
Carolina, for Approval of Renewable Energy	)	AND REPS EMF RIDERS
and Energy Efficiency Portfolio Standard	)	AND 2018 REPS COMPLIANCE
Cost Recovery Rider Pursuant to N.C. Gen.	)	
Stat. § 62-133.8 and Commission Rule R8-67	)	

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

HEARD: Tuesday, November 12, 2019, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Chair Charlotte A. Mitchell, presiding; Commissioners ToNola D. Brown-Bland, Lyons Gray, and Daniel G. Clodfelter.

APPEARANCES:

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 the Using and Consuming Public:

Heather D. Fennell, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On August 13, 2019, Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina Power (DENC or the Company), filed its annual Renewable Energy and Energy Efficiency Portfolio Standard (REPS) Compliance Report and application seeking an adjustment to its North Carolina retail (NC Retail) rates and charges pursuant to N.C. Gen. Stat. § 62-133.8(h) and Commission Rule R8-67. The Commission is required 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 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. Thus, DENC's annual REPS Rider has two components: (1) a forward-looking component to recover DENC's projected REPS compliance costs for the rate period of February 1, 2020 through January 31, 2021 (proposed by DENC as Rider RP); and (2) a REPS Experience Modification Factor (EMF) to true-up any over- or under-recovery of the REPS compliance costs under the previous REPS Riders from July 1, 2018 to June 30, 2019 (proposed by DENC as Rider RPE). DENC's application was accompanied by the testimony and exhibits of George E. Hitch, Senior Market Originator; Alan J. Moore, Regulatory Analyst III; and Emilia L. Catron, Regulatory Analyst for DENC. In its application and pre-filed testimony, DENC sought approval of the proposed REPS Rider RP and REPS EMF rider, which incorporated DENC's proposed adjustments in its NC Retail rates. In addition, DENC requested Commission approval of its 2019 REPS Compliance Report for calendar year 2018 REPS compliance, filed as Company Exhibit GEH-1 attached to the pre-filed direct testimony of Company Witness Hitch. DENC's Application requested an annual revenue requirement of $1,246,561 for the rate period (billing period) of February 1, 2020 through January 31, 2021, to be recovered through updated Rider RP, as well as a REPS EMF revenue requirement of $106,060 to be recovered through Rider RPE.

On September 4, 2019, the Commission issued an Order Scheduling Hearing, Establishing Testimony and Discovery Guidelines, and Requiring Public Notice. Pursuant to that Order, the Commission established deadlines for the filing of petitions to intervene, intervenor testimony and exhibits, Company rebuttal testimony and exhibits, and scheduled the hearing to be held in this proceeding on November 12, 2019.

The intervention and participation of the Public Staff in this docket are recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e). No other party petitioned to intervene.

On October 22, 2019, the Public Staff filed the affidavits of Witnesses Tommy C. Williamson, Jr. and Jenny X. Li.

On October 25, 2019, DENC filed Supplemental Testimony and Exhibits of Company Witnesses Moore and Catron. The Supplemental Testimony updated the Company's Rider RP revenue requirements to $1,246,279 (a $282 decrease to the original Rider RP revenue requirement amount) and Rider RPE to $105,825 (a $235 decrease to the original Rider RPE under recovery amount).

On October 28, 2019, the Public Staff filed revised affidavits of Witnesses Williamson and Li.

On October 30, 2019, DENC filed its Affidavit of Publication.

On October 31, 2019, DENC filed a letter in lieu rebuttal indicating there were no issues in dispute between the Company and the Public Staff based upon the Public Staff's affidavits.

On November 6, 2019, the Public Staff and the Company filed a Joint Motion to Excuse Witnesses from appearing at the November 12, 2019 evidentiary hearing, which was allowed by the Commission pursuant to an Order issued that same day.

This matter came on for hearing as scheduled on November 12, 2019. No public witnesses appeared at the hearing. DENC presented the testimony and exhibits of Witnesses Hitch, Moore, and Catron, and the Public Staff presented the affidavits of Witnesses Williamson and Li. The testimony, exhibits, and affidavits were accepted into evidence.

Based upon the foregoing, including the testimony, exhibits, and affidavits received into evidence at the hearing, the records in the North Carolina Renewable Energy Tracking System (NC-RETS), and the entire record in this proceeding, the Commission makes the following

FINDINGS OF FACT

1. DENC is duly organized as a public utility company under the laws of the State of North Carolina and is subject to the jurisdiction of the Commission. DENC is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public for compensation in North Carolina. DENC is also an electric power supplier as defined in N.C.G.S. § 62-133.8(a)(3). DENC 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. Pursuant to N.C.G.S. § 62-133.8, in 2018 electric power suppliers were required to meet ten percent (10%) of their previous year's NC Retail electric sales by a combination of renewable energy and energy reductions due to the implementation of energy efficiency (EE) measures. In addition, electric power suppliers were required to acquire solar energy, or renewable energy certificates (RECs) for solar energy, by the end of 2018 in an amount equal to at least 0.2% of the previous year's NC Retail sales. The 0.2% solar energy requirement is part of the 10% total REPS requirement. The solar energy sources can be a combination of new solar electric facilities and new metered solar thermal energy facilities. The electric power suppliers of North Carolina were initially required by N.C.G.S. § 62-133.8 to procure a certain portion of their renewable energy requirements beginning in 2012 from electricity generated by poultry and swine waste. However, by Orders issued November 29, 2012, and March 26, 2014, in Docket No. E-100, Sub 113 (collectively, together with the Orders of November 13, 2014, December 1, 2015, October 17, 2016, October 16, 2017, October 8, 2018, and December 16, 2019, the Delay Orders), the Commission delayed the initial swine and poultry waste resource requirements until 2014; in an Order issued November 13, 2014, in the same docket, the Commission granted an additional delay of the initial swine waste requirement until 2015 and established an initial aggregate poultry waste resource requirement of 170,000 megawatt-hours (MWh) for 2014; in an Order issued December 1, 2015, the Commission again granted a further delay of the initial swine waste requirement until 2016 and maintained the aggregate poultry waste resource requirement at 170,000 MWh for 2015; in an Order issued October 17, 2016, the Commission further delayed the initial swine waste requirement for one additional year and maintained the 2016 aggregate poultry waste requirement at 170,000 MWh for 2016; in an Order issued October 16, 2017, the Commission delayed the initial swine waste requirement for one additional year and maintained the aggregate poultry waste requirement at 170,000 MWh for 2017; in an Order issued October 8, 2018, the Commission delayed the initial swine waste requirement for one additional year for electric membership corporations and municipal electric systems but required the electric public utilities (including DENC) to meet 0.02% of their sales using swine waste resources and decreased the aggregate poultry waste requirement to 300,000 MWh; and in an Order issued December 16, 2019, the Commission delayed the initial swine waste requirement for one additional year for electric membership corporations and municipal electric systems but required the electric public utilities (including DENC) to meet 0.04% of their sales using swine waste resources and decreased the aggregate poultry waste requirement to 500,000 MWh.

3. N.C.G.S. § 62-133.8(h)(4) provides that an electric power supplier shall be allowed to recover through an annual rider the incremental costs incurred to comply with the REPS.

4. Pursuant to N.C.G.S. § 62-133.8(b)(2)(e), DENC may use 100% out-of-state RECs to achieve REPS compliance. Under Commission Rule R8-67(e)(2), the total costs reasonably and prudently incurred during the test period to purchase unbundled RECs constitute incremental costs. The projected costs to purchase such RECs during the billing period constitute forecasted incremental costs.

5. DENC has agreed to provide REPS compliance services, including the procurement of RECs, to Town of Windsor pursuant to N.C.G.S. § 62-133.8(c)(2)(e). Town of Windsor's 2019 REPS compliance status is included in DENC's 2019 Compliance Report for compliance year 2018.

6. Taking into account the Commission's Delay Orders, DENC, on its own behalf and on behalf of Town of Windsor, has complied with its 2018 REPS obligations. DENC's 2019 REPS Compliance Report for compliance year 2018 should be approved.

7. For purposes of DENC's annual rider pursuant to N.C.G.S. § 62-133.8(h), the rate period is the 12-month period from February 1, 2020, through January 31, 2021. The test period is the 12-month period July 1, 2018, through June 30, 2019.

8. DENC's micro-grid research project costs are renewable energy research costs recoverable pursuant to N.C.G.S. § 62-133.8(h)(1)(b). DENC's research costs are reasonable for purposes of this proceeding and within the statute's $1,000,000 annual limit.

9. DENC's approach of managing its retail REPS costs separately from the REPS costs for its wholesale customer, Town of Windsor, is reasonable.

10. For purposes of establishing the REPS EMF charge (Rider RPE) in this proceeding, DENC's actually incurred incremental costs of REPS compliance, during the REPS test period, were $868,140. DENC's Rider RP revenues were $762,315. DENC's under-recovery of test-period compliance costs was $105,825.

11. For purposes of establishing the forecasted REPS charge (Rider RP) in this proceeding, DENC's incremental costs of REPS compliance and Kitty Hawk micro-grid costs projected to be incurred during the rate period are $1,246,279.

12. DENC's total adjusted number of customer accounts is 120,954, including 103,324 in the residential class, 17,574 in the commercial class, and 56 in the industrial class.

13. The appropriate monthly amount of the REPS EMF charge (Rider RPE) to be collected during the billing period, per customer account, including the regulatory fee, is $0.04 for residential accounts, $0.24 for commercial accounts, and $1.66 for industrial accounts.

14. The appropriate monthly amount of the forecasted REPS charge to be collected during the billing period (Rider RP), per customer account, including the regulatory fee, is $0.51 for residential accounts, $2.84 for commercial accounts, and $19.17 for industrial accounts. The combined monthly REPS (Rider RP) and REPS EMF (Rider RPE) charges to be collected during the billing period, per customer account, including the regulatory fee, are $0.55 for residential accounts, $3.08 for commercial accounts, and $20.83 for industrial accounts.

15. DENC's combined REPS riders to be charged to each customer account for the billing period are within the annual cost caps established in N.C.G.S. § 62-133.8(h)(4).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-5

These findings of fact are essentially informational, jurisdictional, and procedural in nature and are not contested.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

Section N.C.G.S. § 62-133.8(b)(1) and (c)(1) establish a REPS requirement for all electric power suppliers in the State. These provisions require each electric power supplier to provide a certain percentage of its North Carolina sales from various renewable energy or EE resources. Authorized methods of compliance with the REPS requirement for electric public utilities are listed in N.C.G.S. § 62-133.8(b)(2) as follows: (a) generate electric power at a new renewable energy facility; (b) use 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) reduce energy consumption through the implementation of an EE measure; (d) purchase electric power from a new renewable energy facility; (e) purchase RECs derived from in-State or out-of-state new renewable energy facilities; (f) use electric power that is supplied by a new renewable energy facility or energy saved due to the implementation of an EE measure that exceeds the requirements of this section for any calendar year as a credit towards the requirements of this section in the following calendar year; or (g) electricity demand reduction. In 2018, the electric public utilities were required to meet 10 percent (10%) of their previous year's North Carolina retail electric sales by a combination of the measures authorized by N.C.G.S. § 62-133.8(b). Each of these compliance methods is subject to certain additional limitations and conditions.

Section N.C.G.S. § 62-133.8(c) has similar requirements for electric membership corporations (EMCs) and municipal electric systems.

Section N.C.G.S. § 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 is 0.2% for 2018 and subsequent years.

Section N.C.G.S. § 62-133.8(e) requires a certain percentage of the total electric power sold to retail electric customers in the State to be supplied by swine waste resources. The General Assembly established an initial aggregate 0.07% swine waste resources requirement in 2012, increasing thereafter. N.C.G.S. § 62-133.8(f) requires a specific amount of electric power sold to retail electric customers in the State, or an equivalent amount of energy, to be supplied, or contracted for supply in each year, by poultry waste resources. The General Assembly established an initial aggregate poultry waste resources requirement of 170,000 megawatt-hours (MWh) in 2012, increasing thereafter. 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, DENC's share of the aggregate State set-aside requirements for energy from poultry waste resources is based on the ratio of its North Carolina retail kilowatt-hour (kWh) sales from the previous year divided by the previous year's total North Carolina retail kWh sales for all electric power suppliers. Pursuant to the Commission's Order Establishing Method of Allocating the Aggregate Poultry Waste Resources Set-Aside Requirement issued April 18, 2016, in Docket No. E-100, Sub 113, starting with compliance year 2016, the aggregate poultry waste set-aside obligation shall be allocated among the electric power suppliers by averaging three years of historical retail sales, with the resulting allocation being held constant for three years.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

At the joint request of the State's electric power suppliers, including DENC, the Commission issued the Delay Orders in Docket No. E-100, Sub 113, pursuant to specific authority provided to the Commission by the General Assembly to modify the REPS requirements under N.C.G.S. § 62-133.8(i)(2).

Specifically, the Commission's November 29, 2012 Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Granting Other Relief directed that the swine waste resource set-aside requirement for 2012 be eliminated and that the poultry waste resource requirements for 2012 and subsequent years be delayed for a year. On March 26, 2014, the Commission issued a Final Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Providing Other Relief, approving another one-year delay for both the swine waste resource and poultry waste resource requirements and requiring certain additional reporting by all electric power suppliers, including DENC. On November 13, 2014, the Commission issued an Order Delaying Swine Set-Aside and Providing Other Relief, delaying DENC's and other electric power suppliers' swine waste resource requirement for one year and establishing an initial aggregate poultry waste resource requirement of 170,000 MWh for 2014, to be divided amongst the electric power suppliers. On December 1, 2015, the Commission issued an Order Delaying Swine Set-Aside and Providing Other Relief, granting a further delay of the initial swine waste requirement until 2016, modifying the 2015 poultry waste set-aside requirement to remain at the same level as the 2014 aggregate requirement of 170,000 MWh, and delaying by one year the scheduled increases in the requirement (the requirement was scheduled to increase to 700,000 MWh in the aggregate for all electric power suppliers). On October 16, 2016, the Commission issued an Order Modifying the Swine Waste Set-Aside Requirement and Providing Other Relief, which delayed for one additional year the commencement of the swine waste set-aside requirement. The Commission also modified the 2016 poultry waste set-aside requirement to remain at the same level as the 2014 and 2015 aggregate requirement of 170,000 MWh, and delayed by one additional year the scheduled increases in the requirement (increasing to 700,000 MWh for 2017, and 900,000 MWh for 2018 and each year thereafter). On October 16, 2017, the Commission issued an Order Modifying the swine Waste Set-Aside Requirement and Providing Other Relief, which delayed for one additional year the initial compliance requirement under the swine waste set-aside. The Commission also modified the 2017 poultry waste set-aside requirement to remain at the same level as the 2014 and 2015 aggregate requirement of 170,000 MWh, and delayed by one additional year the scheduled increases in the requirement (increasing to 700,000 MWh for 2018, and 900,000 MWh for 2019 and each year thereafter). Through its Delay Orders, the Commission established that the aggregate statewide poultry waste resource requirement for the State's electric power suppliers, including DENC, is 170,000 MWh for 2016 and 2017, and delayed the initial swine waste requirement until 2018. In its October 8, 2018 Order, the Commission required the electric public utilities, including DENC, to meet 0.02% of their sales using swine waste resources and decreased the aggregate poultry waste requirement to 300,000 MWh. In its December 16, 2019 Order, the Commission required the electric public utilities, including DENC, to meet 0.04% of their sales using swine waste resources and decreased the aggregate poultry waste requirement to 500,000 MWh.

Section N.C.G.S. § 62-133.8(b)(2)(e) provides that an electric power supplier shall achieve no more than 25% of its annual REPS compliance obligations using RECs from out-of-state new renewable energy facilities. However, paragraph (b)(2)(e) specifically exempts any electric public utility with less than 150,000 North Carolina retail jurisdictional customers as of December 31, 2006. The Commission held in its Order on Dominion's Motion for Further Clarification, issued September 22, 2009, in Docket No. E-100, Sub 113, that this exemption applies to DENC for purposes of both its general REPS obligation and individual set-aside requirements pursuant to N.C.G.S. § 62-133.8(d)-(f). DENC may, therefore, achieve 100% of its REPS compliance using RECs generated by out-of-state new renewable energy facilities.

Section N.C.G.S. § 62-133.8(b)(2)(c) provides that an electric power supplier may use energy efficiency certificates (EECs) to meet no more than 25% of its total requirement. This limitation on the use of EECs to meet the total requirement does not apply to municipal suppliers such as Town of Windsor.

Section § 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 through 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 costs and avoided capacity costs. Commission Rule R8-67(e)(2) provides that the reasonable and prudently-incurred costs of unbundled RECs are incremental costs and have no avoided cost component.

Commission Rule R8-67(e)(5) provides that "[t]he REPS EMF 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."

DENC's 2019 REPS Compliance Report for compliance year 2018 stated that pursuant to N.C.G.S. § 62-133.8(c)(2)(e) the Company provided renewable energy resources and compliance reporting services for Town of Windsor.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact appears in DENC's 2019 REPS Compliance Report for compliance year 2018 and in the testimony and exhibits of DENC Witness Hitch and the affidavit of Public Staff Witness Williamson. In addition, the Commission takes judicial notice of information contained in NC-RETS.

DENC's 2019 REPS Compliance Report was admitted into evidence as Company Exhibit GEH-1. This report provided the information required by Commission Rule R8-67(c) for DENC and Town of Windsor. Public Staff Witness Williamson stated in his affidavit that he reviewed DENC's 2019 REPS Compliance Report and recommended that it be approved.

DENC's 2019 REPS Compliance Report stated that DENC's 2017 retail electric sales were 4,167,444 MWh and Town of Windsor's were 46,928 MWh. DENC's 10% 2018 total REPS obligation amounted to 416,745 RECs, including 370,092 general obligation RECs, 8,336 solar RECs (0.2% of 4,167,444), 9,932 poultry waste RECs, 834 swine waste RECs, and 27,551 EECs from its portfolio of in-state EE programs approved pursuant to N.C.G.S. § 62-133.9. Town of Windsor's 10% 2018 total REPS obligation amounted to 4,693 RECs, including 4,485 general obligation RECs, 94 solar RECs (0.2% of 46,928) and 114 poultry waste RECs. The 2018 REPS Delay Order delayed the initial swine waste set-aside requirement for municipalities until 2019. Town of Windsor did not use any EECs for compliance. Public Staff Witness Williamson stated in his affidavit that these numbers of RECs met the REPS requirements that 10% of 2017 retail sales must be matched with an equivalent number of RECs in 2018, including 0.2% of 2017 retail sales that must be matched with an equivalent number of RECs derived from solar energy. Witness Williamson confirmed that DENC had placed these numbers of RECs in its own and Town of Windsor's NC-RETS compliance sub-accounts. Witness Hitch testified that out-of-state RECs may be used for 100% of DENC's REPS compliance, but may not be used to meet more than 25% of Town of Windsor's REPS requirements. DENC complied with these limitations. NC-RETS further indicates that DENC complied with the provisions of N.C G.S. §§ 62-133.8(b)(2)(e) and (c)(2)(d).

No party disputed that DENC and Town of Windsor complied with their 2018 REPS requirements, and Witnesses Hitch and Williamson both stated that DENC and Town of Windsor met the 2018 REPS requirements.

Based on the foregoing and all the evidence of record, the Commission finds that DENC and its wholesale customer, Town of Windsor, for which DENC is providing REPS compliance services, have fully complied with the requirements of the REPS for 2018, and that DENC's 2019 REPS Compliance Report for compliance year 2018 should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact appears in DENC's Application, the testimony of DENC Witnesses Hitch, Moore, and Catron, and the affidavits of Public Staff Witnesses Li and Williamson.

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 annual fuel charge adjustment proceedings, which is specified in Rule R8-55(c) for DENC to be the 12-month period ending each June 30. Therefore, the test period to be used for purposes of this proceeding is the period July 1, 2018, through June 30, 2019.

Regarding the rate period, Rule R8-67(e)(4) provides that the REPS and REPS EMF riders shall be in effect for a fixed period that "shall coincide, to the extent practical, with the recovery period for the cost of fuel and fuel-related cost rider established pursuant to Rule R8-55." For DENC, this is February 1, and the subsequent 12-month period. In its current fuel proceeding, Docket No. E-22, Sub 579, and in this proceeding, DENC has proposed that its rate adjustments take effect on February 1, 2020, and remain in effect for a 12-month period.

DENC's test period and rate period were not challenged by any party. Therefore, the Commission finds that the test period and rate period proposed by DENC are appropriate for use in this proceeding.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact appears in the testimony and exhibits of DENC Witnesses Hitch and Moore and the affidavits of Public Staff Witnesses Williamson and Li.

Pursuant to N.C.G.S. § 62-133.8(h)(1), "incremental costs" include, among other things, "all reasonable and prudent costs incurred by an electric power supplier to . . . (b) [f]und research that encourages the development of renewable energy, energy efficiency, or improved air quality, provided those costs do not exceed one million dollars ($1,000,000) per year." Whether specific test period or forecasted rate period expenditures to fund research are eligible for cost recovery through an annual rider pursuant to this provision is determined by the Commission on a case- by-case basis.

DENC Witnesses Hitch and Moore described the status of the Company's micro-grid project, which the Commission approved in the Company's 2013 REPS rider proceeding, Docket No. E-22, Sub 503, as a research project qualifying for REPS rider cost recovery pursuant to N.C.G.S. § 62-133.8(h)(1). DENC's micro-grid project was constructed at the Company's Kitty Hawk district office beginning in February 2014, and was commissioned and placed in service for operation as a micro-grid on July 22, 2014. A fuel cell was added to the project in July 2015.

The confidential exhibits of Company Witness Moore set forth the ongoing operations and maintenance expenses the micro-grid project incurred during the test period.

Public Staff Witness Williamson stated in his affidavit that the Public Staff reviewed DENC's micro-grid research costs as part of its investigation into DENC's Application and did not take issue with the nature of the ongoing costs associated with the project. As part of the discovery process in this proceeding, however, DENC indicated that the micro-grid system was disconnected in August 2016 due to voltage issues at the Company's Kitty Hawk office that the system served. DENC indicated that it is working with an external contractor to evaluate recommissioning and decommissioning options and anticipates finalizing its plan by the end of 2019. The Public Staff recommended that DENC include in its 2020 REPS cost recovery proceeding testimony summarizing DENC's analysis of the issues experienced with the micro-grid project and any actions taken regarding whether to recommission or decommission the project.

The Commission concludes that the research activities proposed by DENC to be funded during the rate period are eligible research costs recoverable under N.C.G.S. § 62-133.8(h)(1)(b), and that such research costs are within the annual limit allowed by statute. The Commission also agrees with the Public Staff's recommendation and DENC should include in its 2020 REPS cost recovery proceeding testimony summarizing DENC's analysis of the issues experienced with the Kitty Hawk micro-grid project and the Company's actions taken regarding whether to recommission or decommission the project.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is found in the testimony and exhibits of DENC Witness Hitch. DENC Witness Hitch testified that the Company purchases RECs for use by Town of Windsor, its wholesale customer, to meet its REPS obligations. However, 75% of Town of Windsor's RECs must be obtained from in-state sources, whereas DENC, pursuant to N.C.G.S. § 62-133.8(b)(2)(e), is exempt from this requirement and may obtain all of its RECs from outside North Carolina. Because of this difference in requirements, DENC has directly assigned to Town of Windsor the costs of RECs used for its REPS compliance, and has excluded them from the REPS costs the Company is seeking to recover in this proceeding. Similarly, Witness Hitch testified, other incremental REPS compliance costs reasonably attributable to Town of Windsor are excluded from the costs that DENC is seeking to recover. The Public Staff made no objection to the manner in which the Company separates its own REPS compliance costs from those incurred on behalf of Town of Windsor. Accordingly, the Commission finds that DENC's approach of managing its retail REPS costs separately from the REPS costs for Town of Windsor is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-15

The evidence supporting these findings of fact appears in the testimony and exhibits of DENC Witnesses Moore and Catron and the affidavits of Public Staff Witnesses Williamson and Li.

As shown in Witness Moore's Supplemental Exhibit AJM-1, Schedule 2, DENC's incremental REPS compliance costs for the test period amounted to $868,140, while its test-period Rider RP revenues totaled $762,315, resulting in an under-recovery of $105,825, to be recovered through Rider RPE. The under-recovery for each customer class is set forth on Witness Catron's Supplemental Exhibit ELC-1, Schedule 3, as follows: $49,596 for the residential class, $50,613 for the commercial class, and $1,116 for the industrial class. These under-recoveries are divided by the total adjusted number of accounts, which are 103,324, 17,574, and 56 for the residential, commercial, and industrial classes, respectively, and further divided by 12 months to determine the monthly per-account charge. The projected incremental costs for the billing period, which are recovered through Rider RP, amount to $1,244,147. These costs are set forth on Supplemental Exhibit ELC-1, Schedule 5, and are broken down by customer class as follows: $632,343 for the residential class, $598,922 for the commercial class, and $12,882 for the industrial class. These incremental costs are divided by the total adjusted number of accounts for each class, and further divided by 12 months to determine the monthly per-account charge.

In her testimony, Witness Catron determined that the appropriate monthly rates for Riders RP and RPE, including the regulatory fee, are as follows:

Customer Class	Forecast Rate (Rider RP)	EMF Rate (Rider RPE)	Total REPS Rate
Residential	$0.51	$0.04	$0.55
Commercial	$2.84	$0.24	$3.08
Industrial	$19.17	$1.66	$20.83

Public Staff Witnesses Williamson and Li described the Public Staff's audit of DENC's REPS costs and recommended approval of DENC's proposed Rider RP and RPE rates. The Commission therefore finds the Company's proposed rates to be reasonable.

IT IS, THEREFORE, ORDERED as follows:

1. That DENC shall establish a REPS Rider RP as described herein, in the amounts approved herein, and that this rider shall remain in effect for a 12-month period beginning February 1, 2020, and expiring January 31, 2021;

2. That DENC shall establish a REPS EMF Rider RPE as described herein, and that this rider shall remain in effect for a 12-month period beginning February 1, 2020, and expiring January 31, 2021;

3. That DENC shall provide an analysis of the issues experienced at its Kitty Hawk micro-grid project in its 2020 REPS cost recovery application as well as any actions taken regarding whether to recommission or decommission the project;

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 No. E-22, Subs 577 and 579, and the Company shall file such notice for Commission approval as soon as practicable, but not later than three (3) working days after the Commission issues orders in all of 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; and

6. That DENC's 2019 REPS Compliance Report is hereby approved, and the RECs and EECs in DENC's and Town of Windsor's 2018 compliance sub-accounts in NC-RETS shall be retired.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of January, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

DOCKET NO. E-22, SUB 579

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina, Pursuant to N.C.G.S. § 62-133.2 and Commission Rule R8-55 Regarding Fuel and Fuel-Related Costs Adjustments for Electric Utilities	)	ORDER APPROVING FUEL CHARGE ADJUSTMENT

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

HEARD: Tuesday, November 12, 2019, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Chair Charlotte A. Mitchell, Presiding; Commissioner ToNola D. Brown-Bland, Commissioner Lyons Gray and Commissioner Daniel G. Clodfelter

APPEARANCES:

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 Carolina Industrial Group for Fair Utility Rates I:

Warren K. Hicks, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

For the Using and Consuming Public:

Lucy E. Edmondson, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On August 13, 2019, Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC or the Company), filed its Application for a fuel charge adjustment, along with accompanying testimony and exhibits, pursuant to N.C. Gen. Stat. § 62-133.2 and North Carolina Utilities Commission (Commission) Rule R8-55 relating to fuel and fuel-related charge adjustments for electric utilities (Application). The application was accompanied by the testimony and exhibits of Katherine E. Farmer, Ronnie T. Campbell, Dale E. Hinson, Tom A. Brookmire, and George G. Beasley.

On September 4, 2019, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice.

On September 6, 2019, Carolina Industrial Group for Fair Utility Rates I (CIGFUR) filed a petition to intervene. The petition was granted on September 17, 2019.

On September 27, 2019, Nucor Steel-Hertford (Nucor) filed a petition to intervene. The petition was granted on October 2, 2019.

On October 4, 2019, the Company filed its affidavit of publication.

On October 22, 2019, the Public Staff filed the direct testimony of Dustin R. Metz and affidavit of Jenny X. Li.

On October 31, 2019, the Company filed a letter in lieu of rebuttal testimony indicating there were no issues in dispute between the Company and the Public Staff based upon the Public Staff's testimony and affidavit.

On November 5, 2019, the Public Staff and the Company filed a joint motion to excuse witnesses from appearing at the November 12, 2019 evidentiary hearing, stating that they had reached agreement on all issues in this docket and had agreed to waive cross-examination of each other's witnesses.

On November 6, 2019, the Commission granted the joint motion to excuse witnesses.

This matter came on for hearing as scheduled on November 12, 2019. No public witnesses appeared at the hearing. DENC presented the testimony and exhibits of witnesses Farmer, Campbell, Hinson, Brookmire, and Beasley, and the Public Staff presented the testimony of witness Metz and affidavit of witness Li. The testimony, exhibits, and affidavits were accepted into evidence.

On December 23, 2019, a joint proposed order was filed by DENC and the Public Staff.

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

FINDINGS OF FACT

1. The Company is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in northeastern North Carolina. The Company is lawfully before this Commission based on 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 June 30, 2019.

3. The Company's fuel procurement practices during the test period were reasonable and prudent.

4. The per books test period system sales are 87,363,222,000 kilowatt-hours (kWh).

5. The per books test period system generation is 90,757,143 megawatt-hours (MWh), which includes various types of generation as follows:

Generation Types	MWh
Nuclear	28,083,596
Coal	9,259,384
Heavy Oil	0
Wood and Natural Gas Steam	1,032,011

Combined Cycle and Combustion Turbine	35,509,724
Solar and Hydro – Conventional and Pumped	4,609,788
Net Power Transactions	15,301,134
Less: Energy for Pumping	(3,038,494)

6. The Company's baseload plants were managed prudently and efficiently during the test period so as to minimize fuel and fuel-related costs.

7. The nuclear capacity factor appropriate for use in this proceeding is 95.7%, which is the estimated nuclear capacity factor for the 12 months beginning February 1, 2020.

8. The adjusted test period system sales for use in this proceeding are 85,389,162,794 kWh.

9. The adjusted test period system generation for use in this proceeding is 88,616,747 MWh, which is categorized as follows:

Generation Types	MWh
Nuclear	28,061,493
Coal (including wood and natural gas steam)	9,950,079
Heavy Oil	0
Combined Cycle and Combustion Turbine	34,331,961
Hydro	4,533,733
Solar	76,055
Net Power Transactions	14,777,975
Less: Energy for Pumping	(3,038,494)

10. A marketer percentage serves as a proxy for fuel costs when actual fuel costs associated with power purchases are not available. A marketer percentage of 71% should be applied in this proceeding to approximate the fuel cost of such power purchases.

11. The adjusted test period system fuel expense for use in this proceeding is $1,783,381,223.

12. The reasonable and appropriate system base fuel factor, as approved in the Commission's Notice of Decision in Docket Nos. E-22, Subs 562 and 566 (Sub 562 Order), is 2.092¢/kWh (including the regulatory fee), and the reasonable and appropriate North Carolina retail class-specific base fuel factors, as also approved in the Sub 562 Order, including the regulatory fee, are as follows:

Customer Class	Class-Specific Base Fuel Factor
Residential	2.118 ¢/kWh
SGS & PA	2.115 ¢/kWh
LGS	2.098 ¢/kWh
Schedule NS	2.036 ¢/kWh
6VP	2.065 ¢/kWh
Outdoor Lighting	2.118 ¢/kWh
Traffic	2.118 ¢/kWh

13. DENC filed this fuel charge adjustment Application in conjunction with its general rate case filed on March 29, 2019, in Sub 562. All prospective components of fuel costs are included in the base fuel rates that take effect pursuant to the Sub 562 Order. Therefore, DENC will not have a Rider A in this proceeding.

14. The appropriate North Carolina retail test period jurisdictional fuel expense under-collection is ($550,353), and the adjusted North Carolina retail jurisdictional test period system sales are 4,308,591,154 kWh.

15. The appropriate experience modification factors (EMF or Rider B) for this proceeding (including the regulatory fee) are as follows:

Customer Class	EMF Billing Factor
Residential	0.014 ¢/kWh
SGS &PA	0.014 ¢/kWh
LGS	0.014 ¢/kWh
Schedule NS	0.013 ¢/kWh
6VP	0.013 ¢/kWh
Outdoor Lighting	0.014 ¢/kWh
Traffic	0.014 ¢/kWh

16. The class-specific base fuel components approved in the Sub 562 Order should be adjusted by EMF Rider B increments for each class as set forth in Finding of Fact No. 15. Therefore, the total fuel factors to be billed to the Company's retail customers during the February 1, 2020 through January 31, 2021 fuel charge billing period, including the regulatory fee, are as follows:

Customer Class	Class-Specific Total Factor
Residential	2.132 ¢/kWh
SGS &PA	2.129 ¢/kWh
LGS	2.112 ¢/kWh
Schedule NS	2.049 ¢/kWh
6VP	2.078 ¢/kWh
Outdoor Lighting	2.132 ¢/kWh
Traffic	2.132 ¢/kWh

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, jurisdictional, and procedural in nature and is not controverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

North Carolina General Statute Section 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish the Commission in an annual fuel charge adjustment proceeding for an historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending June 30 as the test period for the Company. The Company's filing was based on the 12 months ended June 30, 2019.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is contained in the direct testimony and exhibits of Company witnesses Hinson and Brookmire.

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every ten years and each time the utility's fuel procurement practices change. The Company's current fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A, on December 20, 2013.

In his direct testimony, Company witness Hinson stated that domestic natural gas production increased during the test period in conjunction with an increase in natural gas exports as well as an increase in domestic natural gas demand, particularly in the electric generation and industrial sectors. He stated that despite weather volatility in January and February 2019, natural gas prices averaged lower than the previous winter period. He went on to explain that for the first half of the test period, coal prices rose, but that there was a steady decline in coal prices for the second half of the test period. He stated that after a short period of decline, oil prices have had upward momentum for the test period.

Witness Hinson described the Company's fuel procurement practices and explained that the Company continues to follow the same procurement practices it has in the past in accordance with its report filed in Docket No. E-100, Sub 47A. He also testified to the Company's price hedging program under which it price hedges commodities needed for power generation using a range of volume targets, gradually decreasing over a three-year period.

In regard to natural gas procurement, witness Hinson explained that the Company employs a disciplined natural gas procurement plan to ensure a reliable supply of natural gas at competitive prices. He stated that through periodic solicitations and the open market, the Company serves its gas-fired fleet using a combination of day-ahead, monthly, seasonal, and multiyear physical gas supply purchases. Witness Hinson also described how the Company evaluates its diverse portfolio of pipeline transportation and storage contracts to determine the most reliable and economical delivered fuel options for each power station, and how this portfolio of natural gas transportation contracts provides access to multiple natural gas supply and trading points from the Marcellus shale region to the southeast region. He also noted that the Company actively participates in the interstate pipeline capacity release and physical supply markets as well as longer-term, pipeline expansion projects that will augment its transportation portfolio and enhance reliability at a reasonable cost. Witness Hinson testified that, since the Company's 2018 fuel charge adjustment proceeding, the Company has continued to utilize more natural gas to serve its customers' electricity needs, noting that during the test period in this case, energy production at its gas-fired power stations accounted for about 39.1% of the electricity produced for customers. Finally, he noted that in late 2018, the Company added the Greensville County Power Station (Greensville Station or Greensville) to its regulated fleet, in addition to retiring certain older, less efficient natural gas units in March 2019.

In regard to coal procurement, witness Hinson testified that the Company employs a multi-year physical procurement plan to ensure a reliable supply of coal, delivered to its generating stations by truck or rail, at competitive prices. The Company accomplishes this by procuring long-term coal requirements primarily through periodic solicitations and secondarily on the open market for short-term or spot needs. He noted that this blend of contract terms creates a diverse coal fuel portfolio and allows the Company to proactively manage its fuel procurement strategy, contingency plans, and any risk of supplier non-performance.

Witness Hinson also testified that the Company has a varied procurement strategy for its biomass stations depending on their geographical region. He stated that the Company's biomass stations at Hopewell and Southampton continue to be served by multiple suppliers under both short and long-term agreements, which enables the Company to increase the reliability of its biomass supply by diversifying its supplier base. He also noted that the Company continues to purchase long-term fuel supply through one supplier for its Altavista Power Station, and to procure biomass needs for the Virginia City Hybrid Energy Center via short and long-term contracts with various suppliers.

Finally, witness Hinson described how, with respect to its oil procurement practices, the Company purchases No. 2 fuel oil and No. 6 fuel oil requirements on the spot market and optimizes its inventory, storage, and transportation to ensure reliable supply.

Company witness Brookmire testified that the nuclear fuel market has softened considerably in the past seven to eight years, largely due to the earthquake and tsunami in Japan in March 2011, but also due to reductions in demand. He noted that some reductions in supply have in part offset some of the downward trend in demand. Witness Brookmire indicated that the price for conversion services has experienced some upward price life due to production cuts in the U.S. He also noted that the cost for enrichment services has stabilized somewhat during the test period, and that despite prices in this market still being depressed, there appears to be more balance in the supply and demand of enrichment services. He explained that while the price trend in the U.S. domestic nuclear fuel fabrication industry continues to be difficult to measure due to the lack of a spot market, the general consensus is that costs will continue to increase due to regulatory requirements, reduced competition, and underserved demand in the U.S. and abroad, and financial distress recently experienced by parent companies for U.S. nuclear fuel fabricators. He also pointed out that there may be some short-term price lift on front-end components due to the potential restart of several more reactors in Japan and the growth of China's nuclear energy program.

Witness Brookmire stated that these changes in market costs have not significantly impacted the Company's projected near-term costs, as the Company's current mix of longer-term front-end component contracts has reduced its exposure to the market price volatility that has occurred over the past several years. Witness Brookmire also pointed out that the 18-month refueling schedule for the Company's nuclear plants delays the full effect of any significant changes in a component price. He also noted that the Company has been active in the market and has some market-based and fixed price contracts that allow the Company to take advantage of current lower prices. Witness Brookmire testified that the Company continues to follow the same procurement practices as it has in the past in accordance with the procedures filed in Docket No. E-100, Sub 47A.

Witness Brookmire also testified that the President announced he will take no action with regard to the Department of Commerce's recommendation on the Section 232 petition filed by two U.S. miners in January 2018, and that no quotas or tariffs will be imposed on foreign-supplied uranium as a result. However, he stated that the President, in his decision on the uranium Section 232 case, requested that a high level interagency Working Group be formed to investigate means to improve the commercial viability of the domestic nuclear fuel supply chain, and that the Working Group's final report is expected in October 2019. He testified that any action stemming from the Working Group's recommendations could have an impact on nuclear fuel prices, but that any such impact would be far less significant than those resulting from either tariffs or quotas.

No party offered testimony contesting the Company's fuel procurement practices. Based on the foregoing, the Commission concludes that the Company's fuel procurement practices during the test period were reasonable and prudent.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-5

The evidence for these findings of fact is contained in the direct testimony and exhibits of Company witnesses Campbell and Farmer.

Company witness Campbell's Schedule 3 shows that the Company's per books test period system sales were 87,363,222,000 kWh, and witness Farmer's Schedule 3 shows that the Company's per books test period system generation was 90,757,143 MWh. Witness Farmer's Schedule 3 showed that the per books test period system generation is categorized as follows:

Generation Types	MWh
Nuclear	28,083,596
Coal	9,259,384
Heavy Oil	0
Wood and Natural Gas Steam	1,032,011
Combined Cycle and Combustion Turbine	35,509,724
Solar and Hydro – Conventional and Pumped	4,609,788
Net Power Transactions	15,301,134
Less: Energy for Pumping	(3,038,494)

No other party offered testimony on the level of per books test period system MWh sales or generation. The Commission thus concludes that the foregoing test period per books levels of sales and generation are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding of fact is contained in the direct testimony of Company witness Farmer and the testimony of Public Staff witness Metz.

For purposes of determining the EMF rider, Commission Rule R8-55(k) requires that 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 Generating Availability Report of the North American Electric Reliability Corporation (NERC), appropriately weighted for size and type of plant, 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 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. Rule R8-55(k) also provides that, if a utility does not meet either standard, a rebuttable presumption is created that the increased cost of fuel was incurred imprudently and a disallowance may be appropriate. 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 facilities and any unusual events.

In her direct testimony, Company witness Farmer testified to the performance of the Company's major generating units during the test period. Witness Farmer also testified that the Company's net capacity factors during the test period for its four nuclear units were:

North Anna Unit 1	101.1%
North Anna Unit 2	89.9%
Surry Unit 1	101.3%
Surry Unit 2	90.6%

Thus, the aggregate capacity factor for the Company's nuclear units during the test period was 95.7%, which exceeded the five-year industry weighted average capacity factor of 91.4% for the period 2013-2017 for 800-999 megawatt (MW) units, as reported by NERC in its latest Generating Availability Report. Witness Farmer testified in addition that, for the same five-year period (i.e., 2013-2017), the Company's net nuclear capacity factor was 94.7%, compared to the national average of 91.4%. Based on these figures, she stated that the Company's nuclear fleet performance during the test period was clearly better than the industry five-year average for comparable units.

Public Staff witness Metz testified that the Company met the standards of Commission Rule R8-55(k) with both an actual system-wide capacity factor and a two-year simple average of the system wide capacity factor that exceeded the NERC weighted average capacity factor.

Witness Metz also discussed three outages occurring during the test year that the Public Staff investigated. These outages included an approximate 200-day outage at Scott Solar I, a Company-owned 17 MWAC photovoltaic solar facility, from a lightning strike on September 2, 2018, and two separate approximately one-day outages at the North Anna Power Station. Witness Metz, however, testified that the Public Staff did not recommend a disallowance of replacement power costs due to these outages, as the Public Staff, based on its investigation of the outages, did not conclude that there had been imprudence or mismanagement on the Company's part. He went on to explain that although the Public Staff was not recommending any disallowances, there were three important reasons to bring these outages to the Commission's attention.

First, he testified that it is important to report to the Commission any concerns related to the operations or status of the Company's generation fleets, as well as any trends that merit attention. He stated that there is value in bringing these issues to the Company's attention to indicate areas of plant operation that are of interest to the Public Staff or the Commission, or would be of interest in future proceedings should these issues continue or recur. Second, he explained that the events that contributed to these outages were of particular concern to the Public Staff, but, again, that the Public Staff did not find that there was imprudence or mismanagement on the Company's part. He testified that to the extent the Company has not already done so, the Public Staff believes that the Company should implement and continue mitigation actions to prevent future occurrences of the nature identified in the Public Staff's investigations of these outages. Finally, witness Metz testified that, to the extent these issues continue or recur, in future fuel factor proceedings the Public Staff could conclude that there had been imprudence or mismanagement on the Company's part, which may justify the Public Staff recommending a disallowance of future power replacement costs.

Witness Metz next detailed the three outages, the first of which occurred at Scott Sola I, a Company-owned 17 MWAC photovoltaic facility, from a lightning strike on September 2, 2018. The facility was repaired, but during plant startup, a transformer fire occurred. Witness Metz explained that the transformer fire was caused by faulty electrical connections that had been repaired following the lightning event. The Company's evaluation revealed that the electrical assemblies were performed incorrectly or exhibited poor workmanship. Witness Metz testified, however, that the Company performed tests on the electrical connections after the initial repairs, but that the test did not reveal the embedded failure risks of the incorrectly installed electrical connections, and that post-installation visual inspections would not have been able to identify the issues listed in the report. Therefore, although the Public Staff did not conclude that there had been imprudence or mismanagement by the Company, witness Metz testified that it is crucial for DENC to ensure that quality workmanship is used on all generation assets, and that part of DENC's supervision and control should include having policies and procedures in place to provide direction, documentation, and oversight of contractual agents' work.

Regarding the nuclear-related outages at North Anna Power Station, witness Metz testified that although the outages occurred at different physical locations, they had some issues in common. However, witness Metz testified that in reviewing the Company's responses to Public Staff discovery, as well as the Company self-initiated action items well underway by the time of the Company's filing in this docket, the Company had implemented a corrective action program to help mitigate and prevent future occurrences of this type.

The Commission appreciates the Public Staff's investigation of DENC's outages occurring during the test period. Based on the Public Staff's investigation of these outages as testified to by witness Metz, the Commission accepts the Public Staff's recommendation in regard to these outages that there be no finding of Company imprudence or mismanagement, and thus there be no disallowance of replacement power costs. To the extent the Company experiences outages of a similar nature in the future, the Commission will consider evidence pertaining to any such outages, as it would for any outage, in future proceedings to determine whether the Company has managed its baseload plants prudently and efficiently.

Based upon the evidence in the record, the Commission concludes that DENC managed its baseload plants prudently and efficiently so as to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding of fact is contained in the direct testimony of Company witness Farmer.

Witness Farmer testified that for the 12-month rate period ending January 31, 2021, North Anna Unit 1 is projected to operate at a net capacity factor of 100.4%, North Anna Unit 2 is projected to operate at a net capacity factor of 92.4%, Surry Unit 1 is projected to operate at a net capacity factor of 100.2%, and Surry Unit 2 is projected to operate at a net capacity factor of 89.6%. Based on this projection, the Company normalized expected nuclear generation and fuel expenses in developing the proposed fuel cost rider. DENC's projected fuel costs are based on a 95.7% nuclear capacity factor, which is what DENC anticipates for the 12 months from February 1, 2020 through January 31, 2021, the period the new rates will be in effect. No party offered testimony contesting the projected normalized system nuclear capacity factor.

Based on the foregoing evidence, the Commission concludes that a projected normalized system nuclear capacity factor of 95.7% is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding of fact is contained in the direct testimony of the Company witness Beasley and the testimony of the Public Staff.

Witness Beasley testified that he was sponsoring the calculation of the adjustment to the Company's system sales for the 12 months ended June 30, 2019, due to changes in usage, weather normalization, and customer growth. Witness Beasley stated the adjustment is consistent with the methodology used in the Company's last general rate case (Docket No. E-22, Sub 532) and the last fuel charge adjustment case (Docket No. E-22, Sub 558). Witness Beasley adjusted total system Company sales by 1,974,059,206 kWh. This adjustment is the sum of adjustments for changes in usage, weather normalization, and customer growth. The Public Staff reviewed and accepted these adjustments. No other party offered or elicited testimony on the adjustment.

Based on the foregoing, the Commission concludes that the adjustments for changes in usage, weather normalization, and customer growth are reasonable and appropriate adjustments for use in this proceeding. The adjusted system sales for the 12 months ended June 30, 2019, are 85,389,162,794 kWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding of fact is contained in the direct testimony of Company witness Farmer.

Company witness Farmer presented an adjustment to per books MWh generation for the 12-month period ended June 30, 2019, to incorporate nuclear generation based upon the expected future operating parameters for each unit. Other sources of generation were then normalized, including an adjustment for weather, customer growth, and increased usage. This methodology for normalizing test period generation resulted in an adjusted generation level of 88,616,747 MWh, which includes various types of generation as follows:

Generation Types	MWh
Nuclear	28,061,493
Coal (including wood and natural gas steam)	9,950,079
Heavy Oil	0
Combined Cycle and Combustion Turbine	34,331,961
Hydro	4,533,733
Solar	76,055
Net Power Transactions	14,777,975
Less: Energy for Pumping	(3,038,494)

No other party offered or elicited testimony on the adjusted test period system generation for use in this proceeding. Thus, based on the foregoing, the Commission concludes that the adjusted test period system generation level of 88,616,747 MWh is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is contained in the Sub 562 Order, the direct testimony of Company witness Farmer, and the affidavit of Public Staff witness Li.

In her direct testimony, Company witness Farmer testified that as filed in the 2019 base rate case in Docket No. E-22, Sub 562, the Company is using an updated marketer percentage of 71% to approximate the percentage of unreported power purchase costs related to fuel. Therefore, witness Farmer utilized the updated 71% marker percentage to calculate the Company's costs associated with purchases of power from the PJM Interconnection, L.L.C. market and dispatchable non-utility generators. Public Staff witness Li stated that the Public Staff does not object to the use of a marketer percentage of 71%, subject to the Commission's final order in the Company's 2019 rate case.

Consistent with the Sub 562 Order and based on the evidence in this proceeding, the Commission concludes that it is reasonable for the Company to apply a 71% marketer percentage to purchases from suppliers that do not provide DENC with actual fuel costs as a proxy for actual fuel costs associated with such purchases in this proceeding.

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

The evidence for these findings of fact is contained in the direct testimony of Company witnesses Farmer and Beasley, and the testimony of Public Staff witness Metz.

Company witness Farmer presented the Company's system fuel expense for the test period and the normalized system fuel expenses for the upcoming rate period of $1,783,381,223. She testified that the fuel under-recovery experienced by the Company during the test year was primarily driven by moderate winter weather and the absence of major spikes or movements in commodity prices. She further testified that she used the expense normalization methodology that has been used by the Company and approved in previous North Carolina annual fuel factor proceedings. Specifically, the first step in computing normalized system fuel expense is to calculate nuclear generation based on the expected future operating parameters for each unit. The expected generation from the nuclear units was calculated for the 12-month period ending January 2021. Other sources of generation were then normalized for the test period. The total of coal, heavy oil, combustion turbine and combined cycles, non-utility generation (NUG), and purchased energy during the test period was then calculated. A percentage of this total was then calculated for each of these resources. Normalized generation was computed by applying these percentages to a new total, including an adjustment for weather, customer growth, increased usage, and the net change in nuclear generation. She stated that this methodology for normalizing the test period generation resulted in adjusted annual system energy requirements of 88,616,747 MWh.

Witness Farmer also testified that the addition of DENC's 1,588 MW Greensville Station in December 2018, as well as the Colonial Trail West Solar Facility expected to be in service by December 2019, will benefit system fuel expense. She stated that the system fuel expense in this case is adjusted to reflect the expected full-year fuel benefits related to the Greensville Station. She also stated that the Company placed 10 generating units into "cold reserve," and that these units were retired in March 2019 and are no longer in operation. In addition, she stated that the power purchase contracts for the 200 MW associated with the Roanoke Valley NUG expired in March 2019 and the 218 MW associated with another NUG contract was terminated in April 2019. She testified that the Company does not anticipate a significant impact to system fuel expense from these changes. Finally, she noted that due to the enactment of House Bill 589 and House Bill 374, the Company can now recover the total delivered costs, including capacity and non-capacity costs, associated with certain purchases of power from qualifying facilities (QFs) under the Public Utility Regulatory Policies Act of 1978 that are not subject to economic dispatch or curtailment. She stated that reflecting those costs increases system fuel expense allocated to the North Carolina jurisdiction by approximately $44.7 million.

Company witness Beasley presented the Company's calculation of the base fuel component for the North Carolina jurisdiction and each customer class. He first determined the average system base fuel factor of 2.092 ¢/kWh, based on system fuel expenses of $1,783,381,223, and system sales of 85,389,162,794 kWh, that reflected adjustments for changes in usage, weather normalization, and customer growth. Witness Beasley also presented the calculations used to differentiate the jurisdictional base fuel component by voltage to determine the class fuel factors, and testified that these are consistent with the methodology used in the Company's previous fuel proceeding, Docket No. E-22, Sub 558. Witness Beasley also testified that in Sub 562, the Company would update the base fuel component for each class to be equal to the system fuel expense rate, adjusted for respective losses calculated in this case. He stated that therefore the fuel cost Rider A in this case would be set to $0.00000/kWh for all classes.

Public Staff witness Metz testified that the Public Staff recommended approval of the base fuel factors as shown in his Table 2. These factors are the same as those contained at Company Additional Supplemental Exhibit PBH-1, Schedule 3, which accompanied the additional supplemental testimony of Paul B. Haynes filed in Sub 562, and are as follows for each of the Company's North Carolina retail customer classes:

Customer Class	Class-specific Base Fuel Factor
Residential	2.118 ¢/kWh
SGS &PA	2.115 ¢/kWh
LGS	2.098 ¢/kWh
Schedule NS	2.036 ¢/kWh
6VP	2.065 ¢/kWh
Outdoor Lighting	2.118 ¢/kWh
Traffic	2.118 ¢/kWh

No other party offered or elicited testimony on the adjusted test period system fuel expense for use in this proceeding. In the Sub 562 Order, the Commission approved the marketer percentage, the system base fuel factor, and the North Carolina retail class-specific base fuel factors. Based upon that approval and the evidence presented in this proceeding, the Commission concludes that the appropriate level of fuel expenses to be used to set the prospective, or forward-looking, fuel factor in this proceeding is $1,783,381,223, the appropriate system average base fuel factor (including regulatory fee) is $ 0.02092 per kWh, and the appropriate class-specific base fuel factors (including regulatory fee) are as set forth in Table 2 of Public Staff witness Metz's testimony in this case.

The Commission further concludes that because the class-specific factors have been incorporated in the base rates approved in Sub 562, fuel cost Rider A should be set to $0.00000/kWh for all classes.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-15

The evidence for these findings of fact is contained in the Company's Application, the direct testimony of Company witnesses Campbell, Farmer, and Beasley, as well as the direct testimony of Public Staff witness Metz and the affidavit of Public Staff witness Li.

Company witness Farmer's direct testimony explained moderate winter weather and the absence of major spikes or movements in commodity prices during the test year resulted in a minor under-recovery of fuel costs. Company witness Campbell testified that the fuel costs allocated to North Carolina jurisdictional customers totaled $92,397,802, while the Company received fuel revenues total $91,847,449. The difference between the fuel costs and the fuel revenues resulted in an under-recovery of $550,353 for the test period. To determine the EMF (Rider B), Company witness Beasley divided this net balance by the adjusted jurisdictional test period sales of 4,308,591,154 kWh. He then used customer class expansion factors to differentiate the uniform factor by voltage to determine the North Carolina retail jurisdictional voltage differentiated EMF fuel factors at the sales level applicable to each class.

Public Staff witness Li's affidavit stated that the Public Staff had reviewed the calculations of the EMF provided by DENC, and based on that review recommended that DENC's EMF increment rider (Rider B) for each customer class be based on a net under-recovery of fuel and fuel-related costs of $550,353 and the Company's pro forma North Carolina retail sales of 4,308,591,154 kWh. This conclusion is consistent with the Company's Application. She stated that this produces an EMF increment rider (Rider B), of $0.00013 per kWh, including the regulatory fee, for all North Carolina retail customer classes.

Based on the evidence in this proceeding, the Commission concludes that the appropriate North Carolina retail test period jurisdictional fuel expense under-collection is $550,353 and that the adjusted North Carolina jurisdictional test period sales appropriate for computing the EMF (Rider B) are 4,308,591,154 kWh.

Company witnesses Farmer and Beasley, as well as Public Staff witnesses Metz and Li, testified regarding Rider A1 approved in the Sub 562 Order. Company witnesses Farmer and Beasley explained that to reduce DENC's anticipated over-recovery for the second half of 2019, and to further mitigate the effect of the November 1, 2019 non-fuel base rate increase, the Company proposed to implement Rider A1, a three-month decrement rider, for each class to be effective November 1, 2019 through and including January 31, 2019. Company witness Beasley indicated that the Company was requesting that the Rider A1 rates be set to ($0.00375)/kWh for all classes be approved to allow for a seamless, no impact, transition of total fuel rates ($/kWh) between November 1, 2019, and February 1, 2020, based on the Company's proposed rates in this proceeding. The Commission approved Rider A1 in the Sub 562 Order.

The Commission concludes that the appropriate EMF Rider B increments for this proceeding, including interest and the regulatory fee, are as follows:

Customer Class	EMF Billing Factor
Residential	0.014 ¢/kWh
SGS &PA	0.014 ¢/kWh
LGS	0.014 ¢/kWh
Schedule NS	0.013 ¢/kWh
6VP	0.013 ¢/kWh
Outdoor Lighting	0.014 ¢/kWh
Traffic	0.014 ¢/kWh

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding of fact is cumulative and is contained in the direct testimony and exhibits of Company witnesses Farmer, Campbell, Brookmire, and Beasley, the testimony of Public Staff witness Metz and affidavit of Public Staff affiant Li.

Based upon the above findings and conclusions, the Commission finds and concludes that the total net fuel factors (¢/kWh) are determined as follows (including regulatory fee):

Customer Class	Total Net Fuel Factor
Residential	2.132 ¢/kWh
SGS &PA	2.129 ¢/kWh
LGS	2.112 ¢/kWh
Schedule NS	2.049 ¢/kWh
6VP	2.078 ¢/kWh
Outdoor Lighting	2.132 ¢/kWh
Traffic	2.132 ¢/kWh

IT IS, THEREFORE, ORDERED as follows:

1. That effective beginning with usage on and after February 1, 2020, the Company shall implement a Fuel Cost Rider A of $0.00000/kWh for all classes as approved and set forth in the Evidence and Conclusions for Findings of Fact Nos. 11 and 12 above;

2. That EMF Rider B increments as approved and set forth in the Evidence and Conclusions for Findings of Fact Nos. 14-15 above, shall be instituted and remain in effect for usage from February 1, 2020, through January 31, 2021;

3. That the Company shall file appropriate rate schedules and riders with the Commission in order to implement the fuel charge adjustments approved herein no later than five working days from the date of this Order; and

4. That the Company shall work with the Public Staff to prepare a joint proposed Notice to Customers of the rate adjustments ordered by the Commission herein and in Docket Nos. E-22, Subs 562, 577, and 578, and the Company shall file such proposed notice for Commission approval as soon as practicable.

ISSUED BY ORDER OF THE COMMISSION
This the 23rd day of January, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

DOCKET NO. E-7, SUB 1228

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC	)	
Pursuant to G.S. 62-133.2 and NCUC	)	ORDER APPROVING FUEL
Rule R8-55 Relating to Fuel and Fuel-Related	)	CHARGE ADJUSTMENT
Charge Adjustments for Electric Utilities	)	

HEARD: Tuesday, June 9, 2020, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Tuesday, June 9, 2020 at 1:00 p.m., remotely via Webex.

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

APPEARANCES:

For Duke Energy Carolinas, LLC:

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For Sierra Club:

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For the Using and Consuming Public:

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BY THE COMMISSION: On February 25, 2020, Duke Energy Carolinas, LLC (DEC) 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, Brett Phipps, Regis Repko, Steven D. Capps, and Kevin Y. Houston.

Petitions to intervene were filed by CIGFUR on March 19, 2020; by NCSEA on March 23, 2020; by the Sierra Club on April 14, 2020; and by CUCA on May 8, 2020. The Commission granted CIGFUR's petition to intervene on March 23, 2020, NCSEA's petition to intervene on March 24, 2020, the Sierra Club's petition to intervene on April 15, 2020 and CUCA's petition to intervene on May 12, 2020. The intervention of the Public Staff is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e).

On March 17, 2020, 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, DEC rebuttal testimony, required the provision of appropriate public notice, and mandated compliance with certain discovery guidelines.

On June 5, 2020 and June 25, 2020, DEC filed affidavits of publication indicating that the public notice had been provided in accordance with the Commission's procedural order.

On May 7, 2020, DEC filed the supplemental testimony and revised exhibits and work papers of Kimberly D. McGee. Witness McGee presented revised rates reflecting the impacts related to updated numbers presented in her direct exhibits and workpapers regarding projections included in the billing period as well as the inclusion of overrecovery amounts in the EMF period related to January 2020– March 2020. These updated numbers resulted in an overall decrease in the amount requested in the original application.

On May 18, 2020, the Public Staff filed the Affidavit of Jenny X. Li and the Testimony of Dustin R. Metz. On May 18, 2020, The Sierra Club filed testimony and exhibits of John A. Rosenkranz.

On May 28, 2020, DEC filed the rebuttal testimony of Kimberly D. McGee. On May 29, 2020, DEC filed a motion to excuse all Company and Public Staff witnesses.

On June 1, 2020, the Commission granted the motion and excused all DEC and Public Staff witnesses from appearing at the evidentiary hearing.

On May 29, 2020, the Commission issued an Order Scheduling Remote Hearings for Expert Witness Testimony due to the COVID-19 pandemic. All parties subsequently filed notices consenting to remote hearings.

On June 18, 2020, DEC filed to correct exhibit titles which omitted the revised designation on several of the revised exhibits originally filed with the supplemental testimony of Kimberly D. McGee.

The case came on for hearing remotely by WebEx as scheduled on June 9, 2020. The prefiled direct and supplemental testimonies of DEC's witnesses, the prefiled affidavit and testimony of the Public Staff's witnesses were received into evidence. No other party presented witnesses or exhibits, and no public witnesses appeared at the hearing.

On June 25, 2020, the Commission issued a notice requiring that briefs and proposed orders be filed by July 24, 2020.

On July 24, 2020, DEC and the Public Staff filed a joint proposed order.

Also on July 24, 2020, the 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:

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 December 31, 2019 (test period).

3. In its application, direct, supplemental, and rebuttal testimony including exhibits in this proceeding, DEC requested a total decrease of $144 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 include Experience Modification Factor (EMF) riders and take into account fuel and fuel-related cost underrecoveries and overrecoveries experienced during the test period, including the update period of January 2020 – March 2020. The overall underrecovery for the test period is $57 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.

6. The test period per book system sales are 87,911,333 megawatt-hours (MWh). The test period per book system generation (net of auxiliary use and joint owner generation) and purchased power is 94,408,998 MWh and is categorized as follows:

Net Generation Type	MWh
Coal	20,916,177
Natural Gas, Oil and Biomass	15,489,537
Nuclear	45,243,922
Hydro – Conventional	2,427,405
Hydro Pumped Storage	(713,520)
Solar DG	142,127
Purchased Power – subject to economic dispatch or curtailment	7,993,064
Other Purchased Power	2,613,134
Interchange Power	297,152
Total Net Generation	94,408,998

7. The appropriate nuclear capacity factor for use in this proceeding is 94.39%.

8. The North Carolina retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 58,622,539 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	22,444,481
General Service/Lighting	23,688,550
Industrial	12,489,508
Total	58,622,539

9. The projected billing period (September 2020-August 2021) sales for use in this proceeding are 88,383,239 MWh on a system basis and 58,460,089 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	22,067,951
General Service/Lighting	23,951,115
Industrial	12,441,023
Total	58,460,089

10. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 93,353,096 MWh and is categorized as follows:

Generation Type	MWh
Coal	14,450,043
Gas Combustion Turbine (CT) and Combined Cycle (CC)	24,629,409
Nuclear	44,515,757
Hydro	4,305,885
Net Pumped Storage Hydro	(3,219,894)
Solar Distributed Generation (DG)	385,094
Purchased Power	8,286,802
Total	93,353,096

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 $27.30/MWh.
b. The gas CT and CC fuel price is $22.87/MWh.
c. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $21,603,715.
d. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.04/MWh.
e. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared) is $272,892,569.
f. System fuel expense recovered through intersystem sales is $21,248,787.

12. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $983,087,687.

13. The Company's North Carolina retail jurisdictional fuel and fuel-related expense under-collection for purposes of the EMF was $57.1 million, consisting of an underrecovery for the residential, general service/lighting, and industrial classes of $8.2 million, $15.8 million and $33.2 million respectively.

14. The decrease in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-7, Sub 1190 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: 1.6027 cents/kilowatt-hour (kWh) for the Residential class; 1.7583 cents/kWh for the General Service/Lighting class; and 1.6652 cents/kWh for the Industrial class.

16. The appropriate EMF increments established in this proceeding, excluding the regulatory fee, are as follows: 0.0364 cents/kWh for the Residential class; 0.0666 cents/kWh for the General Service/Lighting class; and 0.2658 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: 1.6391 cents/kWh for the Residential class; 1.8249 cents/kWh for the General Service/Lighting class; and 1.9310 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 (0.1801) cents/kWh, (0.1580) cents/kWh, and (0.3555) 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 0.0364 cents/kWh, 0.0666 cents/kWh, and 0.2658 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

N.C. Gen. Stat. § 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, 2019.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is contained in the Application, the direct and supplemental testimony of Company witness McGee, and the entire record in this proceeding. This finding is not contested by any party. Public Staff Witness Metz testified that the inclusion of Clemson CHP steam revenues in projected cost should be revisited once pending litigation in the DEC general rate case can be decided by the Commission. He noted that the steam revenues may need to be adjusted or removed from North Carolina retail cost of service in future fuel proceedings depending on the Commission's final decision in the general rate case.

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 97.09% during the test period. This capacity factor, as well as the Company's 2-year average capacity factor of 96.19%, exceeded the five-year industry weighted average capacity factor of 91.6% for the period 2014 - 2018 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 twentieth consecutive year, DEC's seven nuclear units achieved a system average capacity factor exceeding 90%, which included three refueling outages. During 2019, DEC's seven nuclear units collectively achieved the highest annual net generation and annual capacity in the Company's history. Both Catawba Unit 1 and Oconee Unit 1 established new annual generation records during 2019. The Oconee station, Oconee Unit 3, and McGuire Unit 2 all recorded their second highest annual net output during 2019.

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 2014 through 2018, and is categorized by generator type:

Generator Type	Measure	Review Period DEC Operational Results	2014-2018 NERC Average	Nbr of Units
Coal-Fired Test Period	EAF	76.9%	77.3%	712
	NCF	36.2%	54.8%	
	EFOR	7.4%	9.3%	
Coal-Fired Summer Peak	EAF	92.6%	n/a	n/a
Total CC Average	EAF	78.0%	84.9%	333
	NCF	71.3%	53.6%	
	EFOR	0.37%	5.1%	
Total CT Average	EAF	83.2%	87.5%	750
	SR	100.0%	98.3%	
Hydro	EAF	83.4%	80.2%	1,063

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.

W.S. Lee Station conducted an outage in the Fall 2019. The primary purpose for the W.S. Lee Station outage was for Transmission to perform Bus Tie Breaker and 100kv Bus Junction Breakers Upgrades. In the Spring 2019, Dan River combined cycle (CC) conducted major gas turbine overhauls, as well as steam turbine valve and generator inspections. Marshall Unit 2 completed an outage in the Spring 2019. The primary purpose of this outage was to conduct stack repairs and install fly ash piping replacement. Marshall Unit 3 completed an outage in the Spring 2019. The primary purpose of this outage was to perform air preheater maintenance. Marshall Unit 4 completed an outage in the Spring 2019. The primary purpose of this outage was to conduct boiler inspections and stack inspections. W.S. Lee CC completed an outage in Spring 2019. The primary purpose of the outage was to perform inspections and balance of plant maintenance. Buck CC completed an outage in Spring 2019. The primary purpose of the outage was to perform a hot gas path inspection on the gas turbines. Lincoln CT Units 11-16 completed an outage in Spring

2019 to upgrade the turbine control systems. In Fall 2019, Belews Creek Unit 1 preformed a boiler outage. The primary purpose of the outage was to replace the horizonal reheat section of the boiler, burner installation for the natural gas co-fire conversion, and precipitator upgrades. Belews Creek Unit 2 was also in an outage to perform work on common service water pipe replacement between units, continuous emission monitoring system (CEMS) upgrade, main battery replacement, and control system power supply upgrade. Marshall Unit 2 completed an outage in Fall 2019. The primary purpose of this outage was to perform FGD inspections, repair absorber agitators, and replace check valves. Marshall Unit 1 also had an outage in the Fall 2019 to replace the generator and transformer protective relays and air preheater baskets. Cliffside Unit 5 performed work on ammonia tank inspections, catalysts replacement, and turbine valve work in the Fall 2019.

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 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, 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 McGee, Phipps, Repko, and Houston and the testimony of Public Staff witness Metz.

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 Phipps described DEC's fossil fuel procurement practices, set forth in Phipps 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 Phipps, the Company's average delivered cost of coal per ton for the test period was $82.11 per ton, compared to $78.71 per ton in the prior test period, representing an increase of approximately 4%. This includes an average transportation cost of $28.33 per ton in the test period, compared to $29.58 per ton in the prior test period, representing a decrease of approximately 4%. Witness Phipps further testified that the Company's average price of gas purchased for the test period was $3.40 per Million British Thermal Units (MMBtu), compared to $3.84 per MMBtu in the prior test period, representing a decrease of approximately 11%. The cost of gas is inclusive of gas supply, transportation, storage and financial hedging.

Witness Phipps stated that DEC's coal burn for the test period was 8.1 million tons, compared to a coal burn of 8.7 million tons in the prior test period, representing a decrease of approximately 7%. The Company's natural gas burn for the test period was 123.9 MMBtu, compared to a gas burn of 128.8 MMBtu in the prior test period, representing a decrease of approximately 4%. The net decrease in DEC's overall natural gas burn was primarily driven by gas to coal switching as a result of the new coal rail transportation rate that went into effect March 1, 2019.

Witness Phipps stated that coal markets continue to be distressed and there has been increased market volatility due to a number of factors, including: (1) deteriorated financial health of coal suppliers; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which have lowered overall domestic coal demand; (3) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency (EPA) regulations for power plants; (4) changing demand in global markets for both steam and metallurgical coal; (5) uncertainty surrounding regulations for mining operations; (6) tightening supply as bankruptcies, consolidations and company reorganizations have allowed coal suppliers to restructure and settle into new, lower on-going production levels.

He 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 Phipps stated that DEC's current coal burn projection for the billing period is 5.4 million tons, compared to 8.1 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 $73.90 per ton for the billing period compared to $82.11 per ton in the test period. This includes an average projected total transportation cost of $28.46 per ton for the billing period, compared to $28.33 per ton in the test period.

Witness Phipps 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 Phipps further testified that DEC's current natural gas burn projection for the billing period is approximately 201.9 MMBtu, which is an increase from the 123.9 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 Belews Creek, and Marshall Units 3 and 4 as a result of the dual fuel conversions being commercially available over the course of the billing period, combined with increased generation output from Lincoln CT. The current average forward Henry Hub price for the billing period is $2.44 per MMBtu, compared to $2.63 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 Phipps, 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 conducts spot market solicitations throughout the year to supplement term contract purchases, taking into account changes in projected coal burns and existing coal inventory levels.

Witness Phipps 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 Phipps, 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.

Finally, in response to the Commission's August 7, 2019 Order Approving Fuel Charge Adjustment in Docket No. E-7, Sub 1190 (2019 Fuel Order), Witness Phipps testified to the results of the Company's review of historic price fluctuations and whether its current method of forecasting and hedging should be adjusted to mitigate the risk of significant underrecovery of fuel costs. Based on its evaluation, the Company determined that no adjustments were needed to its current method of forecasting or to its physical hedging program. However, the Company continues to refine and add modeling capabilities that will provide additional information to help with analyzing fuel forecasts and needed procurement activities, and associated ranges of potential costs. The Company also recommends extending financial hedging activities for a lower percentage in rolling years four and five to mitigate cost risks for customers as explained in more detail in Phipps Confidential Exhibit 4.

N.C. Gen. Stat. § 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.

N.C. Gen. Stat. §§ 62-133.2(a1)(4), (5), (6), and (7) permit the recovery of the cost of no-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 consider the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at 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 respective customers.

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. The Commission also finds that the Company satisfactorily complied with the obligation under the 2019 Fuel Order to evaluate historic price fluctuation.

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 87,911,333 MWh, and test period per book system generation and purchased power amounted to 94,408,998 MWh (net of auxiliary use and joint owner generation). The test period per book system generation and purchased power are categorized as follows (McGee Exhibit 6):

Net Generation Type	MWh
Coal	20,916,177
Natural Gas, Oil and Biomass	15,489,537
Nuclear	45,243,922
Hydro – Conventional	2,427,405
Hydro Pumped Storage	(713,520)
Solar DG	142,127
Purchased Power – subject to economic dispatch or curtailment	7,993,064
Other Purchased Power	2,613,134
Interchange In/Out	297,152
Total Net Generation	94,408,998

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 87,911,333 MWh and system generation and purchased power of 94,408,998 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 94.39% 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 91.60% for the period 2014-2018 as reported in the NERC Brochure during the period of 2014 to 2018.

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 capacity factor, the Commission concludes that the 94.39% nuclear capacity factor, and its associated generation of 59,363,957 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 Exhibit 4, Company witness McGee set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 58,622,539 MWh, comprised of Residential class sales of 22,444,481 MWh, General Service/Lighting class sales of 23,688,550 MWh, and Industrial class sales of 12,489,508 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 88,383,239 MWh. The projected level of generation and purchased power used was 93,353,096 MWh (calculated using the 94.39% 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	14,450,043
Gas Combustion Turbine (CT) and Combined Cycle (CC)	24,629,409
Nuclear	44,515,757
Hydro	4,305,885
Net Pumped Storage Hydro	(3,219,894)
Solar Distributed Generation (DG)	385,094
Purchased Power	8,286,802
Total	**93,353,096**

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	22,067,951
General Service/Lighting	23,951,115
Industrial	12,441,023
Total	**58,460,089**

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 Phipps and the affidavit of Public Staff witness Metz.

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 $27.30/MWh.
B. The gas CT and CC fuel price is $22.87/MWh.
C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $21,603,715.
D. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.04/MWh.

E. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared) is $272,892,569.

F. System fuel expense recovered through intersystem sales is $21,248,787.

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 Metz 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. Witness Metz does however recommend to the Commission that the steam revenues included in the projected period be subject to adjustment in future fuel proceedings depending on the final Commission decision regarding the Clemson CHP unit in the general rate case pending before the Commission at the time of this filing.

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 Metz.

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 2019.

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 $983,087,687. Public Staff witness Metz 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 $983,087,687 is reasonable.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

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 affidavit of Public Staff affiant Li and testimony of witness Metz.

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 under-collection for purposes of the EMF, the method for allocating the decrease 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 reagent and by-product projection to incorporate additional revenue associated with the sale of steam by-products produced from the generation of electricity by the Clemson CHP unit, and (2) inclusion of the overcollection balances for the update period January 2020 – March 2020 in the (over-)/undercalculation.

Public Staff affiant 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 underrecoveries of $8,172,161, $15,770,030, and $33,198,354 for the Residential, General Service/Lighting, and Industrial classes, respectively. Li recommended that DEC's EMF riders for each customer class be based on these net fuel and fuel-related cost underrecovery amounts and on the Company's proposed normalized North Carolina retail sales of 22,444,481 MWh for the residential class, 23,688,550 MWh for the general service/lighting class, and 12,489,508 MWh for the industrial class, as proposed by the Company. Li stated that these amounts produce EMF increment riders for each North Carolina retail customer class as follows, excluding the regulatory fee:

Residential	0.0364 cents per kWh
General Service/Lighting	0.0666 cents per kWh
Industrial	0.2658 cents per kWh

Company witness McGee 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 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 2019 fuel and fuel-related cost recovery proceeding in Docket No. E-7, Sub 1190. No party opposed the use of this allocation method. Public Staff witness Metz 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 $983,087,687 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 1190, 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 this 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 1190 (excluding regulatory fee).

E-7 Sub 1228			
	Residential	General Service Lighting	Industrial
Description	cents/kWh	cents/kWh	cents/kWh
Base Fuel	1.7828	1.9163	2.0207
Prospective Component	(0.1801)	(0.1580)	(0.3555)
EMF Component	0.0364	0.0666	0.2658
Total Fuel Factor	1.6391	1.8249	1.9310

E-7 Sub 1190			
	Residential	General Service Lighting	Industrial
Description	cents/kWh	cents/kWh	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 1228 — 1190 (excluding regulatory fee):

Change in Fuel Rates			
	Residential	General Service Lighting	Industrial
Description	cents/kWh	cents/kWh	cents/kWh
Base Fuel	-	-	-
Prospective Component	(0.2099)	(0.1978)	(0.2282)
EMF Component	(0.1011)	(0.0261)	0.0569
Total Fuel Factor	(0.3110)	(0.2239)	(0.1713)

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 affiant Li and witness Metz 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 1.6391 cents/kWh for the Residential class, 1.8249 cents/ kWh for the General Service/Lighting class, and 1.9310 cents/kWh for the Industrial class, excluding regulatory fee, consisting of the prospective fuel and fuel-related cost factors of 1.6027 cents/kWh, 1.7583 cents/kWh, and 1.6652 cents/kWh, EMF increments of 0.0364 cents/kWh, 0.0666 cents/kWh, and 0.2658 cents/kWh, all respectively, excluding the regulatory fee.

IT IS, THEREFORE, ORDERED:

1. That, effective for service rendered on and after September 1, 2020, 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 (0.1801) cents/kWh, (0.1580) cents/kWh, and (0.3555) 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 0.0364 cents/kWh for the Residential class, 0.0666 cents/kWh for the General Service/Lighting class, and 0.2658 cents/kWh for the Industrial class (excluding the regulatory fee). The EMF increments are to remain in effect for service rendered through August 31, 2021.

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 Nos. E-7, Sub 1229 and E-7, Sub 1231, 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.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of August, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

DOCKET NO. E-7, SUB 1229

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC,	)	
for Approval of Renewable Energy	)	ORDER APPROVING REPS AND
and Energy Efficiency Portfolio Standard	)	REPS EMF RIDERS AND 2019 REPS
(REPS) Compliance Report and Cost Recovery	)	COMPLIANCE REPORT
Rider Pursuant to North Carolina General	)	
Statute § 62-133.8 and Commission Rule R8-67	)	

HEARD: Tuesday, June 9, 2020 at 9:33 a.m. in the Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Tuesday, June 9, 2020, at 1:00 p.m., remotely via Webex

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

APPEARANCES:

For Duke Energy Carolinas, 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 Carolina Industrial Group for Fair Utility Rates III:

Warren K. Hicks, Bailey & Dixon, LLP, Post Office Box 1351, Raleigh, North Carolina 27601

For North Carolina Sustainable Energy Association:

Benjamin Smith, Regulatory Counsel, North Carolina Sustainable, Energy Association, 4600 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Tim R. Dodge, Staff Attorney, Gina C. Holt, Staff Attorney and Nadia L. Luhr, Staff Attorney, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On February 25, 2020, Duke Energy Carolinas, LLC (DEC or the Company) filed its 2019 REPS Compliance Report and application seeking an adjustment to its North Carolina retail rates and charges pursuant to N.C. Gen. Stat. § 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 Renewable Energy and Energy Efficiency Portfolio Standard (REPS), N.C.G.S. § 62-133.8(b), (d), (e), and (f) and to true up any underrecovery or overrecovery of compliance costs. DEC's application was accompanied by the testimony and exhibits of Megan W. Jennings, Renewable Compliance Manager, and Veronica I. Williams, Rates and Regulatory Strategy Manager. In its application and prefiled testimony, DEC sought approval of its proposed REPS Rider, which incorporated the Company's proposed adjustments to its North Carolina retail rates.

On March 17, 2020, 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.

The North Carolina Sustainable Energy Association (NCSEA), the Carolina Industrial Group for Fair Utility Rates III (CIGFUR), and the Carolina Utility Customers Association, Inc. (CUCA) filed separate petitions to intervene in this docket, and the interventions were allowed by the Commission. The intervention and participation by the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On May 15, 2020, DEC filed the supplemental testimony and revised exhibits of witnesses Jennings and Williams.

On May 18, 2020, the Public Staff filed the affidavit of Michelle M. Boswell, Staff Accountant in the Accounting Division of the Public Staff, and the testimony of Jay B. Lucas, Utilities Engineer in the Electric Division of the Public Staff.

On May 20, 2020, DEC and the Public Staff filed a joint motion to excuse all witnesses from the evidentiary hearing. On June 2, 2020, the Commission granted the motion.

On May 29, 2020, the Commission issued an Order Scheduling Remote Hearings for Expert Witness Testimony due to the COVID-19 pandemic. All parties subsequently filed consent to remote hearings.

On June 5, 2020, and June 25, 2020, DEC filed the required affidavits of publication for the public notice in accordance with the Commission's March 17, 2020 Order.

The matter came on for hearing by Webex on June 9, 2020. DEC presented the testimony and exhibits of witnesses Jennings and Williams, and the Public Staff presented the affidavit and testimony of its witnesses Boswell and Lucas, respectively. All prefiled testimony, affidavits, and exhibits from the DEC and Public Staff witnesses were received into evidence.

On June 23, 2020, DEC filed corrected exhibits.

On June 25, 2020, the Commission issued a notice requiring that briefs and proposed orders be filed by July 24, 2020.

On July 24, 2020, DEC and the Public Staff filed a joint proposed order.

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 makes the following:

FINDINGS OF FACT

1. DEC 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. DEC 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 2019, the Company must generally supply an amount of at least 10% of its previous year's North Carolina (NC) retail electric sales (Total Requirement) by a combination of renewable energy and energy reductions due to the implementation of energy efficiency measures. Also, in 2019, energy in the amount of at least 0.20% of the previous year's total electric power sold by DEC to its North Carolina retail customers must be supplied by solar energy resources (Solar Set-Aside Requirement).

3. Beginning in 2012, N.C.G.S. § 62-133.8(e) and (f) require DEC 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 Statewide North Carolina retail sales. In its December 16, 2019 Order Modifying the Swine and Poultry Waste

Set-Aside Requirements and Providing Other Relief and its February 13, 2020 Errata Order, (2019 Delay Orders), issued in Docket No. E-100, Sub 113, the Commission modified the 2019 swine waste set-aside requirement for DEC, Duke Energy Progress, LLC (DEP) and Dominion Energy North Carolina to 0.04% of prior year North Carolina retail sales and delayed for one year the scheduled increases to the requirement (Swine Waste Set-Aside Requirement). The 2019 Delay Orders eliminated the 2019 swine waste set-aside requirement for electric membership corporations and municipalities and delayed scheduled increases for one year. In addition, the 2019 Delay Orders modified the 2019 Statewide poultry waste set-aside requirement to 500,000 MWh and delayed the subsequent scheduled increases by one year (Poultry Waste Set-Aside Requirement).

4. Pursuant to N.C.G.S. § 62-133.8(c)(2)(e), DEC has agreed to provide compliance services, including the procurement of renewable energy certificates (RECs), to the following electric power suppliers: Blue Ridge Electric Membership Corporation (EMC), the Town of Dallas, the Town of Forest City, the Town of Highlands, and Rutherford EMC (collectively the Wholesale Customers).

5. DEC complied with the 2019 Solar Set-Aside Requirement, for itself and the Wholesale Customers for which DEC provided compliance services for the 2019 compliance year, by submitting for retirement 124,357 RECs procured or generated from solar electric facilities and metered solar thermal energy facilities. DEC also complied with the 2019 Poultry Waste Set-Aside Requirement, for itself and the Wholesale Customers for which DEC provides compliance services, by submitting for retirement 176,285 poultry waste RECs and 23,822 Senate Bill 886 RECs (which count as 47,644 poultry waste RECs), for a total of 223,929 poultry waste RECs. The Company complied with the 2019 Swine Waste Set-Aside Requirement that applied to electric public utilities only, and did not apply to the Wholesale Customers, by submitting for retirement 23,793 swine waste RECs. Finally, DEC submitted for retirement 5,845,612 general requirement (General Requirement) RECs, representing the 2019 Total Requirement for DEC North Carolina retail and the Wholesale Customers, net of the Solar Set-Aside Requirement, Swine Waste Set-Aside Requirement, and Poultry Waste Set-Aside Requirement detailed above.

6. DEC and the Wholesale Customers for which DEC provided compliance services met their 2019 REPS obligations, except for those from which they had been relieved under the Commission's orders in Docket No. E-100, Sub 113.

7. The Company's ability to comply with its 2020 Poultry Waste Set-Aside Requirement is dependent on the performance of current poultry waste-to-energy contracts, several of which are ramping up production in 2020. In addition, new poultry waste-to-energy projects are scheduled to come online during 2021 to meet future requirements.

8. DEC's ability to comply with the 2020 Swine Waste Set-Aside Requirement is dependent on the performance of swine waste-to-energy developers on current contracts, particularly achievement of projected delivery requirements and commercial operation milestones.

9. DEC's REC inventory available for future use properly includes RECs generated from net metering customers receiving electric service under schedules other than a time-of-use schedule with demand rates (NMNTD customers).

10. DEC has RECs in its inventory that were generated by its own hydroelectric (hydro) facilities that it cannot use to meet its REPS requirements because those hydro facilities are renewable energy facilities, but not new renewable energy facilities. DEC exchanged a portion of these hydro RECs for an equal number of RECs in the inventory of the North Carolina Electric Membership Corporation (NCEMC) that are qualified to meet DEC's general compliance requirement. DEC executed contracts with NCEMC for the REC exchanges pursuant to the Commission's conclusion that the exchanges are reasonable and serve the public interest in its August 17, 2018 Order Approving REPS and REPS EMF Riders and 2017 REPS Compliance Report in Docket No. E-7, Sub 1162.

11. The Company complied with the Commission's August 15, 2019 Order Approving REPS and REPS EMF Riders and 2018 REPS Compliance Report (2019 REPS Order), directing the Company and Public Staff to work together to evaluate sales prices of set-aside RECs sold by DEC and include the results of the evaluation and resolution of any issues in DEC's direct testimony in this current DEC cost recovery proceeding. In addition, the Company properly accounted for the amount held in abeyance from last year's REPS proceeding in this year's current REPS cost recovery filing.

12. For purposes of DEC's annual rider pursuant to N.C.G.S. § 62-133.8(h), the test period for this proceeding is the calendar year 2019 (Test Period). The billing period for this proceeding is the 12-month period beginning September 1, 2020 and ending August 31, 2021 (Billing Period).

13. DEC'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 will be approved for this proceeding.

14. The research activities funded by DEC during the test period are incremental costs reasonably and prudently incurred by DEC to fund research that encourages the development of renewable energy, energy efficiency, or improved air quality, and are within the annual $1 million limit established pursuant to N.C.G.S. § 62-133.8(h)(1)(b).

15. No costs associated with the implementation of DEC's Competitive Procurement of Renewable Energy (CPRE) Program are included for recovery in this REPS proceeding. DEC's costs associated with procurement of CPRE renewable energy resources and for the implementation of the Company's CPRE Program were submitted for recovery in its pending CPRE rider in Docket No. E-7, Sub 1231.

16. N.C.G.S. § 62-133.8(h) authorizes an electric power supplier 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.

17. Under Commission Rule R8-67(e)(2), the total costs reasonably and prudently incurred during the Test Period to purchase unbundled RECs constitute incremental costs. The projected costs to purchase such RECs during the Billing Period constitute forecasted incremental costs.

18. DEC appropriately calculated its avoided costs and incremental REPS compliance costs for the Test Period and Billing Period, including those avoided and incremental costs specifically related both to the Company's Solar Photovoltaic Distributed Generation (Solar PVDG) Program and to DEC's other owned solar facilities as required by the following Commission orders: (1) Order Granting Certificate of Public Convenience and Necessity with Conditions, issued December 31, 2008, and its Order on Rconsideration, issued May 8, 2009, in Docket No. E-7, Sub 856; (2) Order Transferring Certificate of Public Convenience and Necessity, issued May 6, 2016, in Docket No. E-7, Sub 1079; (3) Order Transferring Certificate of Public Convenience and Necessity, issued May 16, 2016, in Docket No. E-7, Sub 1098; and (4) Order Granting Certificate of Public Convenience and Necessity (Woodleaf Order) issued June 16, 2016, in Docket No. E-7, Sub 1101. (Collectively, the DEC Solar PV Orders)

19. DEC properly complied with the reporting conditions of the Woodleaf Order in this proceeding.

20. For purposes of establishing the REPS experience modification factor (EMF) rider in this proceeding, the Company's incremental costs for the combined DEC and Wholesale Customer REPS compliance during the Test Period are $32,466,491, and these costs were reasonably and prudently incurred. The Company's projected incremental costs for the combined DEC and Wholesale Customer REPS compliance for the Billing Period are $31,994,020, DEC's Test Period REPS expense undercollections were $260,340 for the residential class and $111,738 for the industrial class, and an overcollection of $(108,375) for the general service 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 $(588,889) for residential, $(423,261) for general service, and $(34,022) for industrial. Total net Test Period credits, including credits for contract-related receipts, for the residential and general service are $(328,549) and $(531,636), respectively. Total net Test Period cost, including an offsetting credit amount for contract-related receipts, is $77,716 for the industrial class. All amounts exclude the North Carolina regulatory fee (regulatory fee).

21. DEC's North Carolina retail prospective Billing Period expenses for use in this proceeding are $16,899,388, $12,011,561, and $919,782, for the residential, general service, and industrial classes, respectively, excluding the regulatory fee.

22. The appropriate monthly REPS EMF riders, excluding regulatory fee, to be (credited to) or charged to customer accounts during the upcoming Billing Period are \$(0.02) for residential accounts, \$(0.18) for general service accounts, and \$1.37 for industrial accounts, excluding the regulatory fee.

23. The appropriate prospective REPS riders per customer account, excluding the regulatory fee, to be collected during the Billing Period are \$0.80 for residential accounts, \$3.99 for general service accounts, and \$16.18 for industrial accounts.

24. 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 \$0.78 for residential accounts, \$3.81 for general service accounts, and \$17.55 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 \$0.78 for residential accounts, \$3.81 for general service accounts, and \$17.57 for industrial accounts.

25. DEC'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 class in N.C.G.S. § 62-133.8(h)(4).

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

The evidence supporting these findings of fact appears in DEC's 2019 REPS Compliance Report, in the direct testimony and exhibits of DEC witnesses Jennings and Williams, in the testimony of Public Staff witness Lucas, and in the affidavit of Public Staff witness Boswell. These findings of fact are essentially informational, jurisdictional and procedural in nature and are not contested.

N.C.G.S. § 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 from a new renewable energy facility; (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 2019, DEC was required to meet a total REPS requirement of 10% of its previous year's North Carolina retail electric sales by a combination of these measures.

N.C.G.S. § 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 2019 is 0.20%.

N.C.G.S. §§ 62-133.8(e) and (f) require DEC and the other North Carolina electric suppliers, 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, DEC's share of the aggregate Statewide 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 2019 Delay Orders, the Commission modified the 2019 Swine Waste Set-Aside Requirement to require only the electric public utilities to comply, set the requirement at 0.04% of North Carolina retail sales, and delayed for one year the scheduled increases in the requirement for all electric power suppliers. In addition, the 2019 Delay Orders also modified the 2019 Statewide Poultry Waste Set-Aside requirement to 500,000 MWh and delayed by one year the scheduled increases in the requirement.

In its 2019 REPS Compliance Report, DEC stated that it provided energy resources and compliance reporting services for Blue Ridge EMC, the Town of Dallas, the Town of Forest City, the Town of Highlands, and Rutherford EMC, as allowed by N.C.G.S. § 62-133.8(c)(2)(e). (Tr. vol. 2, 72-73)

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-8

The evidence supporting these findings of fact appears in DEC's 2019 REPS Compliance Report, in the direct testimony and exhibits of DEC witness Jennings, and in the testimony of Public Staff witness Lucas. In addition, the Commission takes judicial notice of the information contained in NC-RETS. DEC's 2019 REPS Compliance Report was admitted into evidence as Jennings Exhibit No. 1.

Witness Jennings testified that the 2019 REPS Compliance Report provided the information required by Commission Rule R8-67(c) in the aggregate for DEC and the Wholesale Customers for which DEC has agreed to provide REPS compliance services. (Tr. vol. 2, 18)

Witness Jennings further testified that, on behalf of DEC and its Wholesale Customers, the Company submitted for retirement 6,170,047 RECs, which includes 23,822 Senate Bill 886 (SB 886) RECs, each of which counts for two poultry waste and one general REC, to meet its Total Requirement of 6,217,691 RECs. Within this total, the Company submitted for retirement: 124,357 RECs to meet the Solar Set-Aside Requirement; 176,285 RECs, along with

23,822 SB 886 RECs (which count as 47,644 poultry waste set-aside RECs), to meet the Poultry Waste Set-Aside Requirement of 223,929 RECs; and 23,793 RECs to meet the Swine Waste Set-Aside Requirement. (Tr. vol. 2, 19)

Witness Jennings' testimony states that the Billing Period for this Application covers two separate compliance reporting periods with different requirements for each period. In 2020, the Company estimates that it will be required to submit for retirement 6,126,401 RECs to meet its Total Requirement. Within this total, the Company expects to be required to retire the following: 122,532 solar RECs, 42,888 swine waste RECs, and 313,499 poultry waste RECs to meet the requirements set out in N.C.G.S. §§ 62-133.8(d), (e), and (f), respectively. In 2021, the Company estimates that it will be required to submit for retirement 7,563,137 RECs to meet its Total Requirement. Within this total, the Company expects to be required to retire the following: 122,064 solar RECs, 42,725 swine waste RECs, and 403,068 poultry waste RECs, to meet the requirements set out in N.C.G.S. §§ 62-133.8(d), (e), and (f), respectively. (Tr. vol. 2, 19)

Witness Jennings testified that DEC met its 2019 Solar Set-Aside Requirement by procuring and producing 124,357 solar RECs and that, pursuant to the NC-RETS Operating Procedures, the Company submitted these RECs for retirement by transferring these RECs from the Duke Energy Electric Power Supplier Account to the Duke Energy Compliance Sub-Account and the Sub-Accounts of its Wholesale Customers. (Tr. vol. 2, 25)

Witness Jennings testified that DEC met the modified 2019 Poultry Waste Set-Aside Requirement of 223,929 RECs. Pursuant to NC-RETS Operating Procedures, the Company submitted for retirement 176,285 poultry RECs and 23,822 SB 886 RECs (which count as 47,644 poultry waste RECs). Accordingly, the equivalent of 223,929 RECs were submitted for retirement by transferring them from the Duke Energy Electric Power Supplier Account to the Duke Energy Compliance Sub-Account and the Sub-Accounts of its Wholesale Customers. (Tr. vol. 2, 27)

Witness Jennings testified that DEC met the modified 2019 Swine Waste Set-Aside Requirement of 23,793 swine waste RECs. The modified 2019 requirement was applicable to DEC only, not the Wholesale Customers. Pursuant to NC-RETS Operating Procedures, the Company submitted these RECs for retirement by transferring these RECs from the Duke Energy Electric Power Supplier Account to the Duke Energy Compliance Sub-Account. (Tr. vol. 2, 29)

Witness Jennings further testified that the Company complied with its General Requirement for 2019 by submitting 5,845,612 RECs, pursuant to NC-RETS Operating Procedures. The RECs were transferred from the NC-RETS Duke Energy Electric Power Supplier account to the Duke Energy Compliance Sub-Account and the Sub-Accounts of the Wholesale Customers. (Tr. vol. 2, 20)

Witness Jennings testified that future compliance with both the Poultry Waste Set-Aside Requirement and the Swine Waste Set-Aside Requirement is dependent on the performance of energy developers on current contracts and new waste-to-energy projects scheduled to come online. She further testified that production associated with several poultry waste contracts is anticipated to ramp up during 2020, and four new poultry waste-to-energy facilities are currently scheduled to come online in 2021, two of which are gas injection facilities. (Tr. vol. 2, 27-28)

Regarding expected compliance with future Swine Waste Set-Aside requirements, witness Jennings reported that current swine waste-to-energy facilities have encountered numerous difficulties in achieving full contractual REC output, but 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: negotiations for in-state and out-of-state supplies; working extensively with potential suppliers to overcome production risks, or amend contracts to accommodate changing circumstances, or both; and pursuing new biomass and biogas swine resource options; among other efforts. (Tr. vol. 2, 29-31)

Public Staff witness Lucas recommended that the Commission approve DEC's 2019 REPS Compliance Report. (Tr. vol. 2, 94) Specifically, he testified that for 2019 compliance, DEC needed to obtain a sufficient number of RECs and energy efficiency certificates (EECs) derived from any eligible sources so that the total equaled 10% of the 2018 North Carolina retail electricity sales of itself and the Wholesale Customers. Witness Lucas additionally stated that DEC needed to pursue retirement of sufficient solar RECs to match 0.20% of retail sales in 2018 for itself and the Wholesale Customers. In addition, the 2019 Delay Orders modified the requirements for swine and poultry energy established in N.C.G.S. § 62-133.8(e) and (f), requiring retirement of a quantity of swine waste-derived RECs equal to 0.04% of 2018 DEC retail sales, and retirement of an amount of poultry waste-derived RECs matching the pro-rata share of the 500,000 MWh (or the thermal equivalent) Statewide requirement allocated to DEC and the Wholesale Customers. (Tr. vol. 2, 93-94)

No party disputed that DEC had fully complied with the applicable REPS requirements or argued that DEC's 2019 REPS Compliance Report should not be approved.

Based on the evidence presented and the entire record herein, the Commission finds and concludes that DEC and the five Wholesale Customers for which it is providing REPS compliance services have fully complied with the REPS requirements for 2019, as modified by the Commission's 2019 Delay Orders, and that DEC's 2019 REPS Compliance Report should be approved. The Commission further concludes that the RECs and EECs in the related NC-RETS compliance sub-accounts should be permanently retired.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9-10

The evidence supporting these findings of fact is found in the testimony of DEC witness Jennings. In addition, the Commission takes judicial notice of its 2019 REPS Order.

Witness Jennings explained that under the current Net Metering for Renewable Energy Facilities Rider offered by DEC (Rider NM), a customer receiving electric service under a schedule other than a time-of-use schedule with demand rates shall provide any RECs to DEC at no cost. She further stated the Company performed site visits and complied with the other 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 DEC's REC inventory and available for use in meeting future compliance requirements. (Tr. vol. 2, 21-24) No party to this proceeding contested this finding of fact.

Witness Jennings testified that DEC has hydro RECs in its inventory that it cannot use for its own REPS compliance efforts because they were generated by specific hydro generating facilities owned by the Company. In its Order Accepting Registration of Renewable Energy Facilities, Docket No. E-7, Subs 886, 887, 888, 900, 903, and 904, issued July 31, 2009 (July 31, 2009 Order), and its Order Accepting Registration of Renewable Energy Facilities, Docket No. E-7, Subs 942, 943, 945 and 946, issued December 9, 2010, the Commission accepted the registration of these specific hydro facilities as renewable energy facilities, but not as *new* renewable energy facilities. The Commission so concluded because these utility-owned facilities did not meet the delivery requirement of N.C.G.S. § 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 itself to qualify as a new renewable energy facility. (Tr. vol. 2, 34-35) In each of its previous two REPS cost recovery proceedings in Docket No. E-7, Subs 1162 and 1191, the Company proposed exchanging a portion of these hydroelectric RECs for RECs within the inventory of the North Carolina Electric Membership Corporation (NCEMC). The exchanges were at no cost to either party and resulted in DEC acquiring RECs it could use to meet its General Requirement, and in NCEMC obtaining an equal number of RECs it could use to meet its REPS compliance requirements. In its August 17, 2018 Order Approving REPS and REPS EMF Riders and 2017 REPS Compliance Report, the Commission concluded the proposed transfer was reasonable and served the public interest. In its 2019 REPS Order, the Commission concluded the RECs acquired by DEC in exchange for its own hydroelectric RECs were properly included in the Company's inventory of RECs available for future use. Witness Jennings stated the Company has again executed contracts with NCEMC exchanging a portion of these hydroelectric RECs for an equal number of General Requirement RECs in NCEMC's inventory that DEC can use for REPS compliance. (Tr. vol. 2, 35-36)

Based on the foregoing, the Commission finds and concludes that the RECs generated by the net metering facilities as described above, and the RECs acquired in exchange for its own hydroelectric RECs, are properly included in DEC's inventory of RECs available for future REPS compliance use.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding of fact is found in the direct testimony and supplemental testimony of DEC witness Jennings, the supplemental testimony of DEC witness Williams, the testimony of Public Staff witness Jay Lucas, and the affidavit of Public Staff witness Michelle Boswell.

Witness Jennings' direct testimony noted the Commission's requirement in its 2019 REPS Order that the Company and the Public Staff work together to evaluate sales prices of set-aside RECs sold by DEC. Witness Jennings noted that the Commission directed the Company to include the results of the evaluation, and any resolution of issues, in its direct testimony in this current DEC cost recovery proceeding. She described the five REC sales price considerations to be addressed, as recommended by the Public Staff in Docket No. E-7, Sub 1191, and accepted by the Commission in its 2019 REPS Order as the follows:

(1) overhead costs associated with obtaining the REC and subsequent sale of the REC;

(2) an amount to mitigate the interest DEC may pay ratepayers on any REPS EMF overcollection that results from the sale of set-aside RECs;

(3) an amount to ensure that DEC's customers do not bear any risk of REC contracts not materializing or resulting in lower quantities of RECs being generated;

(4) an amount to provide a price signal to other electric power suppliers to encourage them to continue to participate in the development of swine and poultry waste-to-energy resourecs without relying solely on DEC to provide the needed set-aside RECs; and

(5) an amount to encourage DEC to sell RECs, when available, to other North Carolina electric power suppliers for the purpose of assisting with their compliance with the REPS requirements. (Tr. vol. 2, 32-33)

Witness Jennings testified that the Company submitted the following proposals to the Public Staff. When selling set-aside RECs to other electric suppliers, the sales price of these RECs will be determined by taking a weighted average price of all contracts in the combined portfolio of DEC and DEP that were executed for compliance with the respective set-aside for which RECs are being sold, following the same practice the Company has used for past REC sales. In addition to this weighted average price, the Company proposed two adders to address items (1) through (4). To address item (2), the Company proposed an adder in an amount to mitigate the interest DEC is required to pay customers on any REPS EMF overcollection that includes the proceeds from the sale of set-aside RECs. This adder would be retained by the Company to mitigate interest paid to customers in the event of an overcollection for the EMF period, and would be credited in full to customers in the REPS rider calculation if the Company did not overcollect during the EMF period. The second adder would be charged to REC buyers to address items (1), (3), and (4) and would be credited to customers in the relevant REPS EMF rider calculation. Regarding item (5), the Company proposed no specific adder to create an incentive to sell RECs. (Tr. vol. 2, 33-34)

In her supplemental testimony, witness Jennings explained that the Company and the Public Staff continued to work together to evaluate set-aside REC sales prices after her direct testimony was filed. Witness Jennings stated that the Company and the Public Staff had come to an agreement on a proposed REC sales price calculation that will be used when DEC or DEP sell animal waste RECs to other electric suppliers to help those suppliers comply with N.C.G.S. §§ 62-133.8(e) and (f). She explained that the Public Staff recommended calculating the weighted average price of RECs from only those contracted facilities that were operational in the combined portfolio, rather than all executed contracts. In addition, the Public Staff recommended a revision to the sales price adder proposed by the Company to mitigate the interest DEC is required to pay customers on any REPS EMF overcollection that includes the proceeds from the sale of set-aside RECs. The Public Staff proposed a reduction to the overcollection interest mitigation factor equal to the Company's prior-year short-term borrowing rate, to recognize the value received by DEC from holding the sales proceeds pending crediting them to customers. The Company agreed with both recommendations of the Public Staff. (Tr. vol. 2, 55-57)

Public Staff witness Lucas testified that DEC had periodically sold set-aside RECs to other electric power suppliers to assist with their REPS compliance, and described the method previously used by the Company to determine the sales prices of the RECs sold. He further explained, as discussed in DEC witness Jennings' supplemental testimony, that the Public Staff reached an agreement with DEC on a revision to DEC's originally proposed sales price component, which would result in the Company calculating the price based on a weighted average of REC prices from all contracted and operational facilities in DEC and DEP's combined portfolio for each respective set-aside REC type. (Tr. vol. 2, 97-99)

In her affidavit, Public Staff witness Boswell confirmed efforts by the Company and the Public Staff to work together to evaluate the sales prices of set-aside RECs, as directed by the Commission in its 2019 REPS Order. She stated the Public Staff and the Company agreed on the proposed method to calculate the sales price as reflected in the supplemental testimony of DEC witness Jennings, and the supplemental testimony of DEC witness Williams. Witness Boswell stated that based on her review of the sales price calculation, revised as discussed above, she believes the proposed calculation (a) appropriately accounts for and balances the costs associated with the sales, and (b) addresses concerns raised by the Public Staff in the 2019 REPS proceeding in Docket No. E-7, Sub 1191. Public Staff witness Boswell further recommended the calculation be reviewed on an annual basis to verify it is working as designed. (Tr. vol. 2, 105-106)

In her supplemental testimony, Company witness Williams addressed the amount related to set-aside RECs sold that was held in abeyance from the prior year REPS cost recovery proceeding, in accordance with the 2019 REPS Order. She stated that the amount held in abeyance is not included in the calculation of REPS compliance costs used to compute the REPS riders in the current docket. This ratemaking treatment is consistent with DEC's proposed method of calculating REC sales prices as described in DEC witness Jennings' direct and supplemental testimony, and was agreed upon by the Company and the Public Staff. (Tr. vol. 2, 88-90) In her affidavit, Public Staff witness Boswell stated that she reviewed the Company's proposal regarding REC sales prices, and recommended the Commission approve the Company's proposal to exclude the amount held in abeyance in the 2019 REPS cost recovery proceeding from the rider calculations in the current cost recovery proceeding. (Tr. vol. 2, 106)

Based on the foregoing, the Commission finds and concludes the Company properly complied with the Commission's 2019 REPS Order with respect to working with the Public Staff to evaluate set-aside REC sales prices, including specifically addressing the Public Staff's five recommended considerations enumerated above, and including the results of the evaluation, and any resolution of issues, in its direct testimony in this current DEC cost recovery proceeding. The

Company will calculate sales prices for any animal waste RECs sold to assist other electric power suppliers comply with N.C.G.S. §§ 62-133.8(e) and (f) in accordance with the method agreed upon with the Public Staff, as described above, and the calculation will be reviewed on an annual basis as applicable REC sales occur. In addition, DEC's ratemaking treatment of the amount held in abeyance from the prior year REPS cost recovery in the 2019 REPS proceeding in Docket No. E-7, Sub 1191 is appropriate and final.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding is procedural in nature, found in the testimony and exhibits of DEC witness Williams, the testimony of Public Staff witness Lucas, and affidavit of Public Staff witness Boswell, and is not contested by any party.

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 DEC to be the 12 months ending December 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 January 1, 2019 and ending December 31, 2019. (Tr. vol. 2, 60) 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 further 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. (Tr. vol. 2, 62) Witness Williams also testified that the Billing Period for the REPS rider requested in the Company's application is the twelve months beginning on September 1, 2019 and ending on August 31, 2020. (Tr. vol. 2, 60) 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. (Tr. vol. 2, 62) The Test Period and the Billing Period proposed by DEC 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 January 1, 2019 through December 31, 2019.

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

The evidence for these findings of fact can be found in the testimony and exhibits of DEC witnesses Jennings and Williams, the testimony of Public Staff witness Lucas, and the affidavit of Public Staff witness Boswell.

Witness Jennings sponsored Confidential Revised Jennings Exhibit Nos. 2 and 3 to her testimony, wherein she identified the renewable energy and REC costs, as well as "Other Incremental," "Solar Rebate Program," and "Research" costs that the Company has incurred or projects to incur in association with REPS compliance. With respect to research costs, Confidential

Revised Williams Exhibit No. 1 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 Jennings provided testimony and exhibits on the results and status of various studies, the costs of which DEC is including for recovery as research in its incremental REPS cost for the 2019 Test Period. (Tr. vol. 2, 42-51) In his testimony, witness Lucas discussed the research costs submitted by the Company and stated the costs were within the $1,000,000 maximum annual limit allowed, and met the definition of costs qualified to be incurred for research as defined by N.C.G.S. § 62-133.8(h)(1)(b). (Tr. vol. 2, 94-95)

Witness Jennings describes in her 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 by agreed-upon liquidated damages paid by sellers for failure to meet contractual milestones, and amounts paid for administrative contractual amendments requested by sellers. (Tr. vol. 2, 37)

Witness Jennings also testified that, pursuant to N.C.G.S. § 62-155(f), DEC developed a Solar Rebate Program, and she discusses the processes in place to pay rebates, and the resulting effect on the payments made each year. (Tr. vol. 2, 37-39) She further testified that the incremental costs incurred to "provide incentives to customers, including program costs, incurred pursuant to N.C.G.S. § 62-155(f)" are allowed to be recovered under N.C.G.S. § 62-133.8(h). Therefore, she testified that DEC has included for recovery in this filing costs incurred during the EMF period, and projected to be incurred in the Billing Period, related to the implementation of the Solar Rebate Program. These costs include the annual amortization of incentives paid to customers and program administration costs, which include labor, information technology and marketing costs. (Tr. vol. 2, 39-40) 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.

The Commission concludes that the research activities funded by DEC during the Test Period are renewable research 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 further concludes that the Company has complied with the prior Commission orders requiring filing results of such research studies. In addition, the Commission finds that the research information DEC provided is helpful. Therefore, the Commission finds that DEC 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, DEC 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.

The Commission also concludes the costs identified as Other Incremental and Solar Rebate Program are properly recoverable in the REPS EMF and REPS riders calculated in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this finding of fact is found in the testimony of DEC witness Jennings and in the testimony of Public Staff witness Lucas.

In her direct testimony, DEC witness Jennings describes how the CPRE Program will affect DEC's future compliance with its General Requirement, and how the program is reflected in compliance planning. She states that because the Company will use the RECs acquired through the CPRE Program for REPS compliance, CPRE Program implementation costs could be recovered through the REPS rider. She also notes, however, that the Company has elected to recover reasonable and prudently incurred costs incurred to implement the CPRE Program through the CPRE rider in Docket No. E-7, Sub 1231, as contemplated under Commission Rule R8-71(j). (Tr. vol. 2, 24-25)

In his testimony, witness Lucas confirms DEC is not requesting recovery of CPRE Program costs in this current REPS proceeding, and that he generally does not agree with the recovery of any CPRE costs in a REPS rider. He does agree, however, that it is difficult to definitively make such a conclusion before the Commission fully considers CPRE costs in CPRE Program Rider filings or other proceedings. He further cites comments filed jointly by DEC and DEP in Docket No. E-100, Sub 150 specifically addressing cost recovery of bundled CPRE Program RECs through the CPRE Program rider mechanism and reflecting CPRE Program generated RECs used for REPS compliance at zero cost in REPS proceedings. Witness Lucas confirmed the Public Staff's position that it is appropriate to recover CPRE Program implementation costs in a CPRE Program Rider filing pursuant to Rule R8-71(j). (Tr. vol. 2, 95-97)

The Commission concludes that the matter of the inclusion of any CPRE Program implementation costs in the REPS rider is more appropriately considered in the current CPRE Program cost recovery proceeding currently in process in Docket No. E-7, Sub 1231.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-18

The evidence for these findings of fact is found in DEC's Application and in the testimony and exhibits of DEC witnesses Jennings and Williams, the testimony of Public Staff witness Lucas, and the affidavit of Public Staff witness Boswell.

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."

DEC witness Williams testified regarding the calculation of DEC's various incremental costs of compliance with REPS requirements, based on detailed incurred and projected costs provided by witness Jennings. (Tr. vol. 2, 62-64) Witness Williams also described in detail the methods used by the Company to determine the appropriate avoided cost to apply to REPS compliance purchased power agreements, the Company's Solar PVDG Program, and its newer utility-owned solar facilities, in order to calculate the incremental costs for recovery through the REPS rider. She testified that the Company limited cost recovery in this proceeding for its four newer solar facilities as required by the Commission in its DEC Solar PV Orders. (Tr. vol. 2, 64-65) Confidential Revised Williams Exhibit No. 1, page 1, identified total incremental costs incurred during the Test Period for DEC North Carolina retail and the Wholesale Customers as $32,466,491, and Confidential Williams Exhibit No. 1, page 2, showed estimated incremental costs for the Billing Period as $31,994,020.

In her affidavit, Public Staff witness Boswell described the Public Staff's investigation and review of the Company's filing, including its evaluation of DEC's per books incremental costs and revenues, as well as the annual revenue cap for REPS requirements for the Test Period. (Tr. vol. 2, 105) Based on her review of costs submitted for recovery, witness Boswell recommended approval of DEC's proposed monthly and annual REPS EMF decrement riders for the residential and general service customer classes, and DEC's proposed EMF increment rider for the industrial customer class, as filed with its supplemental testimony. (Tr. vol. 2, 106-107) As described by witness Boswell, the items included in the Company's supplemental testimony and exhibits that affected the EMF riders proposed were: (1) correction of an error in the incremental costs in the EMF period; (2) correction of an error in the calculation of the Solar Rebate Program amortization cost; and (3) an update to the percentage of energy efficiency RECs supplied by class. (Tr. vol. 2, 104) In his testimony, witness Lucas stated that the Public Staff agreed with the rates in the supplemental testimony filed by DEC witness Williams on May 15, 2020, and recommended approval of the Billing and EMF components of the total REPS rate as filed therein. (Tr. vol. 2, 100)

Based on the foregoing, the Commission concludes that the correct incremental costs for the adjusted EMF period of January 1, 2019 through December 31, 2019 are $32,466,491. The Commission further concludes the estimated incremental costs for the Billing Period are $31,994,020.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence supporting this finding of fact is found in the testimony of DEC witness Williams.

Witness Williams testified that in its June 16, 2016 Order Granting Certificate of Public Convenience and Necessity (Woodleaf Order) for the Company's Woodleaf solar facility in Docket No. E-7, Sub 1101, the Commission included two conditions related to cost recovery that are relevant to this proceeding. First, the Company agreed to the condition limiting the cost recovery amount in its annual REPS rider filing to the standard offer REC price that DEC was offering to new renewable energy facilities at the time of execution of the Woodleaf construction contract. The second condition relates to DEC's ability to realize certain tax benefits included in the Company's revenue requirements analysis for facility as presented during the Woodleaf CPCN proceeding. The condition provides that, in the appropriate REPS rider and general rate case proceedings, DEC will separately itemize the actual monetization of the tax benefits listed in the Commission's order within its calculation of the levelized revenue requirement per MWh for each facility, so that it may be compared with the monetization of such tax benefits included in the Company's revenue requirement analysis of each facility presented during the CPCN proceedings. To the extent the Company fails to fully realize the tax benefits it originally assumed in its estimated revenue requirements, costs associated with the increased revenue requirements (with a limited exception) will be presumed to be imprudent and unreasonably incurred. The condition further provides that DEC may rebut this presumption with evidence supporting the reasonableness and prudence of its actual monetization of the tax credits. (Tr. vol. 2, 65-66)

Witness Williams testified the Company's Woodleaf solar facility was placed in service in December 2018, and recovery of costs for the facility have been requested in the pending DEC general rate case, Docket No. E-7, Sub 1214. She further stated the Company had updated its revenue requirement calculation in this current REPS rider proceeding, including its current estimates regarding the realization of the tax benefits enumerated in the Woodleaf Order. She described the results of the Company's analysis of the updated tax monetization estimates and other relevant inputs, and indicated the resulting calculated annual revenue requirement was below the original CPCN estimate. With respect to the condition restricting Woodleaf cost recovery in the annual REPS rider, witness Williams testified that the Company limited the amount included for recovery in the rider proposed in this REPS proceeding to the percentage of annual levelized cost equivalent to the standard offer REC price established in the Woodleaf CPCN proceeding. (Tr. vol. 2, 67-70)

Based on the foregoing, the Commission concludes DEC properly complied in this proceeding with the reporting and cost recovery conditions of the Woodleaf Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-25

The evidence supporting these findings of fact appears in DEC's Application, in the testimony and exhibits of DEC witnesses Jennings and Williams, the testimony of Public Staff witness Lucas, and the affidavit of Public Staff witness Boswell.

Revised Williams Exhibit No. 2, Page 3 shows EMF Period undercollections of $260,340 for the residential class and $111,738 for the industrial class, and an EMF overcollection including interest of $(108,375) for the general service class. Revised Williams Exhibit No. 4 shows additional credits for contract receipts by customer class of $(588,889) for residential, $(423,261) for general service, and $(34,022) for industrial. The total EMF period overcollections including interest and contract-related credits, by customer class, are $(328,549) for residential and $(531,636) for general service. The EMF period undercollection net of contract-related credits is

$77,716 for the industrial class. As reflected on Revised Williams Exhibit No. 4, witness Williams calculated monthly per-account REPS EMF credits (excluding regulatory fee) of $(0.02) for residential accounts and $(0.18) for general service accounts, and a monthly per-account REPS EMF charge (excluding regulatory fee) of $1.37 for industrial accounts. Also, on Revised Williams Exhibit No. 4, she calculated the projected REPS costs for the Billing Period of $16,899,388 for the residential class, $12,011,561 for the general service class, and $919,782 for the industrial class. 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 $0.80 for residential accounts, $3.99 for general service accounts, and $16.18 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 $0.78 for residential accounts, $3.81 for general service accounts, and $17.55 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 $0.78 for residential accounts, $3.81 for general service accounts, and $17.57 for industrial accounts. Witness Williams testified that 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 or (decrement) riders of $(0.19), $(2.12), and $16.41, per customer account for DEC's residential, general service, and industrial customers, respectively, excluding the North Carolina regulatory fee. Excluding regulatory fee, the corresponding monthly REPS EMF decrement rider amounts are $(0.02) and $(0.18) for residential and general service customers, respectively, and a monthly REPS EMF increment rider of $1.37 for industrial customers. (Tr. vol. 2, 106-107)

Public Staff witness Lucas recommended the Company's proposed prospective monthly REPS rider amounts per customer account, excluding regulatory fee, of $0.80 for residential accounts, $3.99 for general service accounts, and $16.18 for industrial accounts be approved. Combined with the monthly EMF rider amounts recommended by witness Boswell, witness Lucas recommended approval of the following total monthly REPS charge per customer account, excluding regulatory fee: $0.78 for residential accounts, $3.81 for general service accounts, and $17.55 for industrial accounts. (Tr. vol. 2, 100)

The Commission concludes that DEC's calculations of its REPS and REPS EMF riders are reasonable and appropriate. Accordingly, the Commission finds 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 Revised Williams Exhibit No. 4, are appropriate. Finally, the Commission 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).

IT IS, THEREFORE, ORDERED as follows:

1. That DEC shall establish a REPS rider as described herein, in the amounts approved herein, and that this rider shall remain in effect for a 12-month period beginning on September 1, 2020 and expiring on August 31, 2021;

2. That DEC shall establish an EMF rider as described herein, in the amounts approved herein, and that this rider shall remain in effect for a 12-month period beginning on September 1, 2020 and expiring on August 31, 2021;

3. That DEC shall file the appropriate rate schedules and riders with the Commission in order to implement the provisions of this Order as soon as practicable, but not later than ten days after the date that the Commission issues orders in this docket as well as in Docket Nos. E-7, Sub 1228 and E-7, Sub 1231;

4. That DEC 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-7, Sub 1228 and E-7, Sub 1231, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten days after the Commission issues orders in all three dockets;

5. That DEC's 2019 REPS Compliance Report is hereby approved, and the RECs in DEC's 2019 compliance sub-accounts in NC-RETS shall be retired;

6. That DEC shall continue to 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 DEC shall continue to file a worksheet explaining the discrete costs that DEC includes as "other incremental costs" in all future REPS rider proceedings.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day August, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Joann R. Snyder, Deputy Clerk

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

DOCKET NO. E-7, SUB 1230

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Carolinas, LLC for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to N.C. Gen. Stat. § 62-133.9 and Commission Rule R8-69	)))))	ORDER APPROVING DSM/EE RIDER AND REQUIRING FILING OF PROPOSED CUSTOMER NOTICE

HEARD: Tuesday, June 9, 2020, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina (public witness hearing) and via WebEx Video Conference (expert witness hearing)

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

APPEARANCES:

For Duke Energy Carolinas, LLC:

Kendrick Fentress, Associate General Counsel, Duke Energy Corporation, 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 the Carolina Industrial Group for Fair Utility Rates III:

Warren K. Hicks, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500 P.O. Box 1351, Raleigh, North Carolina 27602

For the North Carolina Sustainable Energy Association:

Benjamin Smith, Regulatory Counsel, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the North Carolina Justice Center, North Carolina Housing Coalition, and the Southern Alliance for Clean Energy:

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

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

For the Using and Consuming Public:

> Lucy E. Edmondson, Nadia L. Luhr, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: N.C. Gen. Stat. § 62-133.9(d) authorizes the North Carolina Utilities Commission (Commission) to approve an annual rider to the rates of electric public utilities, outside of a general rate case, for recovery of all reasonable and prudent costs incurred for adoption and implementation of new demand-side management (DSM) and energy efficiency (EE) measures. The Commission is also authorized to award incentives to electric companies for adopting and implementing new DSM/EE measures, including, but not limited to, appropriate rewards based on (1) the sharing of savings achieved by the DSM and EE measures and/or (2) the capitalization of a percentage of avoided costs achieved by the measures. Commission Rule R8-69(b) provides that every year the Commission will conduct a proceeding for each electric public utility to establish an annual DSM/EE rider to recover the reasonable and prudent costs incurred by the electric utility in adopting and implementing new DSM/EE measures previously approved by the Commission pursuant to Commission Rule R8-68. Further, Commission Rule R8-69(b) provides for the establishment of a DSM/EE experience modification factor (EMF) rider to allow the electric public utility to collect the difference between reasonable and prudently incurred costs and the revenues that were realized during the test period under the DSM/EE rider then in effect. Commission Rule R8-69(c) permits the utility to request the inclusion of utility incentives (the rewards authorized by the statute), including net lost revenues (NLR), in the DSM/EE rider and the DSM/EE EMF rider.

Docket Proceedings

In the present proceeding, Docket No. E-7, Sub 1230, on February 25, 2020, Duke Energy Carolinas, LLC (DEC or Company) filed an application for approval of its DSM/EE rider (Rider EE[1] or Rider 12) for 2021[2] (Application) and the direct testimony and exhibits of Carolyn T. Miller, Rates Manager for DEC, and Robert P. Evans, Senior Manager – Strategy and Collaboration for the Carolinas in the Company's Market Solutions Regulatory Strategy and Evaluation group.

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[1] DEC refers to its DSM/EE Rider as "Rider EE"; however, this rider includes charges intended to recover both DSM and EE revenue requirements.

[2] The Rider EE proposed in this proceeding is the Company's twelfth Rider EE and includes components that relate to Vintages 2017, 2018, 2019, 2020, and 2021 of the cost and incentive recovery mechanism approved in Docket No. E-7, Sub 1032, as modified in Docket No. E-7, Sub 1130. For purposes of clarity, the aggregate rider is referred to in this Order as "Rider 12" or the proposed "Rider EE." Rider 12 is proposed to be effective for the rate period January 1, 2021 through December 31, 2021.

On March 17, 2020, the Commission issued an order scheduling a hearing for June 9, 2020, establishing discovery guidelines, providing for intervention and testimony by other parties, and requiring public notice. DEC filed the affidavits of publication for the public notice as required by the Commission's March 17, 2020 Order.

The intervention of the Public Staff – North Carolina Utilities Commission (Public Staff) is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e). The Carolina Industrial Group for Fair Utility Rates III (CIGFUR) filed a petition to intervene on March 19, 2020, which was granted on March 23, 2020. On March 23, 2020, the North Carolina Sustainable Energy Association (NCSEA) filed a petition to intervene, which was granted on March 24, 2020. On April 17, 2020, the North Carolina Justice Center (NC Justice Center), the North Carolina Housing Coalition ("NC Housing Coalition") and the Southern Alliance for Clean Energy (SACE) filed a joint petition to intervene, which was granted on April 21, 2020. On May 8, 2020, the Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene, which was granted on May 12, 2020.

On May 11, 2020, DEC filed the supplemental testimony and revised exhibits of witness Miller and revised exhibits of witness Evans, which supplemental testimony revised the DSM/EE rates being requested by DEC. On May 13, 2020, DEC filed a motion for additional public hearing and a proposed Revised Public Notice.

On May 13, 2020, the Commission issued an order requiring publication of a second public notice of the scheduled June 9, 2020 public hearing. The order concluded that the Second Public Notice would provide reasonable and adequate notice of the requested changes in DEC's proposed DSM/EE rates, without the need to schedule an additional public hearing. In addition, the order directed DEC to publish the second public notice in newspapers having general circulation in DEC's service area one time at least fifteen days before the June 9, 2020 hearing.

On May 14, 2020, the NC Justice Center, NC Housing Coalition, and SACE (collectively, NC Justice Center, *et al.*) filed a motion for extension of time to file testimony and requested that parties be allowed to appear remotely at the June 9, 2020 hearing due to the ongoing COVID-19 pandemic. On May 18, 2020, the Commission granted the motion for extension and took under advisement the motion for remote hearing.

On May 22, 2020, the NC Justice Center, *et al.*, filed the testimony and exhibits of Forest Bradley-Wright, the Energy Efficiency Director for SACE; and the Public Staff filed the testimony and exhibits of Michael C. Maness, Director of the Accounting Division, David Williamson, Staff Engineer in the Electric Division, and John R. Hinton, Director, Economic Research Division.

On May 29, 2020, the Commission issued an order scheduling a remote hearing for expert witness testimony and requiring parties to file written statements of consent or objection by June 3, 2020, and to file potential cross-examination exhibits by June 4, 2020. All parties filed statements of consent to holding the expert witness hearing by remote means.

On June 1, 2020, DEC filed the rebuttal testimony of Timothy J. Duff and witness Evans.

On June 3, 2019, DEC and the Public Staff filed a joint motion to excuse DEC witness Miller and Public Staff witness Maness from appearing at the June 9, 2020 expert witness hearing, which motion was granted by the Commission on June 5, 2020.

On June 8, 2020, the Public Staff filed the supplemental testimony and revised exhibits of witnesses Williamson and Maness.

On June 9, 2020, DEC, the Public Staff, and the NC Justice Center, *et al.*, filed testimony summaries for their respective witnesses appearing at the remote expert witness hearing.

The case came on for hearing as scheduled on June 9, 2020. No public witnesses appeared at the hearing.

On June 25, 2020, the Commission issued a notice requiring that briefs and proposed orders be filed by July 24, 2020. On July 21, 2020, the Commission issued an order extending the due date until August 13, 2020.

On August 13, 2020, proposed orders were filed by DEC and the Public Staff, and post hearing briefs were filed by DEC and NC Justice Center, *et al.*

Past Pertinent Proceedings

(Docket No. E-7, Subs 831, 938, 979, 1032, 1130, and 1164)

On February 9, 2010, the Commission issued an Order Approving Agreement and Joint Stipulation of Settlement Subject to Certain Commission-Required Modifications and Decisions on Contested Issues in DEC's first DSM/EE rider proceeding, Docket No. E-7, Sub 831 (Sub 831 Order). In the Sub 831 Order, the Commission approved, with certain modifications, the Agreement and Joint Stipulation of Settlement between DEC, the Public Staff, SACE, Environmental Defense Fund (EDF), Natural Resources Defense Council (NRDC), and the Southern Environmental Law Center (SELC) (Sub 831 Settlement), which described the modified save-a-watt mechanism (Sub 831 Mechanism), pursuant to which DEC calculated, for the period from June 1, 2009 until December 31, 2013, the revenue requirements underlying its DSM/EE riders based on percentages of avoided costs, plus compensation for NLR resulting from EE programs only. The Sub 831 Mechanism was approved as a pilot with a term of four years, ending on December 31, 2013.

On February 15, 2010, tbe Company filed an Application for Waiver of Commission Rule R8-69(a)(4) and R8-69(a)(5) in Docket No. E-7, Sub 938 (Sub 938 Waiver Application), requesting waiver of the definitions of "rate period" and "test period." Under the Sub 831 Mechanism, customer participation in the Company's DSM and EE programs and corresponding responsibility to pay Rider EE are determined on a vintage year basis. A vintage year is generally the 12-month period in which a specific DSM or EE measure is installed for an individual participant or group of participants.[1] The Company applied the vintage year concept on a calendar-year basis to the modified save-a-watt portfolio of programs for ease of administration for the Company and customers. Pursuant to the Sub 938 Waiver Application, "test period" is defined as the most recently completed vintage year at the time of the Company's DSM/EE rider application filing date.

On April 6, 2010, the Commission entered an Order Granting Waiver, in Part, and Denying Waiver, in Part. The Order approved the requested waiver of R8-69(d)(3) in part, but denied the Company's requested waiver of the definitions of "rate period" and "test period."

On May 6, 2010, DEC filed a Motion for Clarification or, in the Alternative, for Reconsideration, asking that the Commission reconsider its denial of the waiver of the definitions of "test period" and "rate period," and that the Commission clarify that the EMF may incorporate adjustments for multiple test periods. In response, the Commission issued an Order on Motions for Reconsideration on June 3, 2010 (Sub 938 Second Waiver Order), granting DEC's Motion. The Sub 938 Second Waiver Order established that the rate period for Rider EE would align with the 12-month calendar year vintage concept utilized in the Commission-approved save-a-watt approach (in effect, the calendar year following the Commission's order in each annual DSM/EE cost recovery proceeding), and that the test period for Rider EE would be the most recently completed vintage year at the time of the Company's Rider EE cost recovery application filing date.[2]

On February 8, 2011, in Docket No. E-7, Sub 831, the Commission issued its Order Adopting "Decision Tree" to Determine "Found Revenues" and Requiring Reporting in DSM/EE Cost Recovery Filings (Sub 831 Found Revenues Order), which included, in Appendix A, a "Decision Tree" to identify, categorize, and net possible found revenues against the NLR created by the Company's EE programs. Found revenues may result from activities that directly or indirectly result in an increase in customer demand or energy consumption within the Company's service territory.

On November 8, 2011, in Docket No. E-7, Sub 979, the Commission issued its Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice, in which it approved the Evaluation, Measurement, and Verification (EM&V) agreement (EM&V Agreement) between the Company, SACE, and the Public Staff. Pursuant to the EM&V Agreement, for all EE programs, except for the Non-Residential Smart $aver Customer Rebate Program and the Low-Income EE and Weatherization Assistance Program, actual EM&V results are applied to replace all initial impact estimates back to the beginning of the program offering.

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[1] Vintage 1 is an exception in terms of length. Vintage 1 is a 19-month period beginning June 1, 2009 and ending December 31, 2010, because of the approval of DSM/EE programs prior to the approval of the cost recovery mechanism.

[2] Further, in the Sub 938 Second Waiver Order issued June 3, 2010, the Commission concluded that DEC should true up all costs during the save-a-watt pilot through the EMF rider provided in Commission Rule R8-69(b)(1). The modified save-a-watt approach approved in the Sub 831 Order required a final calculation after the completion of the four-year program, comparing the cumulative revenues collected related to all four vintage years to amounts due the Company, taking into consideration the applicable earnings cap.

For the purposes of the vintage true-ups, these initial EM&V results will be considered actual results for a program until the next EM&V results are received. The new EM&V results will then be considered actual results going forward and will be applied prospectively for the purposes of truing up vintages from the first day of the month immediately following the month in which the study participation sample for the EM&V was completed. These EM&V results will then continue to apply and be considered actual results until superseded by new EM&V results, if any. For all new programs and pilots, the Company will follow a consistent methodology, meaning that initial estimates of impacts will be used until DEC has valid EM&V results, which will then be applied back to the beginning of the offering and will be considered actual results until a second EM&V is performed.

On February 6, 2012, in the Sub 831 docket, the Company, SACE, and the Public Staff filed a proposal regarding revisions to the program flexibility requirements (Flexibility Guidelines). The proposal divided potential program changes into three categories based on the magnitude of the change, with the most significant changes requiring regulatory approval by the Commission prior to implementation, less extensive changes requiring advance notice prior to making such program changes, and minor changes being reported on a quarterly basis to the Commission. The Commission approved the joint proposal in its July 16, 2012 Order Adopting Program Flexibility Guidelines.

On October 29, 2013, the Commission issued its Order Approving DSM/EE Programs and Stipulation of Settlement in Docket No. E-7, Sub 1032 (Sub 1032 Order), which approved a new cost recovery and incentive mechanism for DSM/EE programs (Sub 1032 Mechanism) and a portfolio of DSM and EE programs to be effective January 1, 2014, to replace the cost recovery mechanism and portfolio of DSM and EE programs approved in Docket No. E-7, Sub 831. In the Sub 1032 Order, the Commission approved an Agreement and Stipulation of Settlement, filed on August 19, 2013, and amended on September 23, 2013, by and between DEC, NCSEA, EDF, SACE, the South Carolina Coastal Conservation League (CCL), NRDC, the Sierra Club, and the Public Staff (Stipulating Parties), which incorporates the Sub 1032 Mechanism (Sub 1032 Stipulation).

Under the Sub 1032 Stipulation, the portfolio of DSM and EE programs filed by the Company was approved with no specific duration (unlike the programs approved in Sub 831, which explicitly expired on December 31, 2013). Additionally, the Sub 1032 Stipulation also provided that the Company's annual DSM/EE rider would be determined according to the Sub 1032 Stipulation and the terms and conditions set forth in the Sub 1032 Mechanism, until otherwise ordered by the Commission. Under the Sub 1032 Stipulation, the Sub 1032 Mechanism was required to be reviewed in four years and any proposals for revisions to the Sub 1032 Mechanism were to be filed by parties along with their testimony in the annual DSM/EE rider proceeding.

The overall purpose of the Sub 1032 Mechanism is to (1) allow DEC to recover all reasonable and prudent costs incurred for adopting and implementing new DSM and EE measures; (2) establish certain requirements, in addition to those of Commission Rule R8-68, for requests by DEC for approval, monitoring, and management of DSM and EE programs; (3) establish the terms and conditions for the recovery of NLR (net of found revenues) and a Portfolio Performance

Incentive (PPI) to reward DEC for adopting and implementing new DSM and EE measures and programs; and (4) provide an additional incentive to further encourage kilowatt-hour (kWh) savings achievements. The Sub 1032 Mechanism also includes the following provisions, among several others: (1) it shall continue until terminated pursuant to Commission order; (2) modifications to Commission-approved DSM/EE programs will be made using the Flexibility Guidelines; (3) treatment of opted-out and opted-in customers will continue to be guided by the Commission's Orders in Docket No. E-7, Sub 938, with the addition of an additional opt-in period during the first week in March of each year; (4) the EM&V Agreement shall continue to govern the application of EM&V results; and (5) the determination of found revenues will be made using the Decision Tree approved in the Sub 831 Found Revenues Order. Like the Sub 831 Mechanism, the Sub 1032 Mechanism also employs a vintage year concept based on the calendar year.[1]

On August 23, 2017, in Docket No. E-7, Sub 1130 (Sub 1130), the Commission issued its Order Approving DSM/EE Rider, Revising DSM/EE Mechanism, and Requiring Filing of Proposed Customer Notice (Sub 1130 Order), in which it approved the agreement to revise certain provisions of the Sub 1032 Mechanism reached by the Company and the Public Staff.

Paragraph 69 of the Sub 1032 Mechanism, which describes how avoided costs are determined for purposes of calculating the PPI, was revised such that for Vintage 2019 and beyond, the program-specific avoided capacity benefits and avoided energy benefits will be derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates as of December 31 of the year immediately preceding the annual DSM/EE rider filing date. For the calculation of the underlying avoided energy credits to be used to derive the program-specific avoided energy benefits, the calculation will be based on the projected EE portfolio hourly shape, rather than the assumed 24x7 100-megawatt (MW) reduction typically used to represent a qualifying facility (QF).

Paragraph 19 of the Sub 1032 Mechanism was revised to specify that the avoided costs used for purposes of program approval filings would also be determined using the method outlined in revised Paragraph 69. The specific Biennial Determination of Avoided Cost Rates used for each program approval filing would be derived from the rates most recently approved by the Commission as of the date of the program approval filing.

Paragraph 23 of the Sub 1032 Mechanism was revised, and Paragraphs 23A-D were added, to specify which avoided costs should be used for determining the continuing cost-effectiveness of programs and actions to be taken based on the results of those tests. Pursuant to Paragraph 23, each year the Company files an analysis of the current cost-effectiveness of each of its DSM/EE programs as part of its DSM/EE rider filing. New Paragraph 23A requires the use of the same method for calculating the avoided costs outlined in the revisions to Paragraph 69 to determine the continued cost-effectiveness for each program. Like revised Paragraph 69, Paragraph 23A specifies that the avoided capacity and energy costs used to calculate cost-effectiveness will be derived from the avoided costs underlying the most recent Commission-approved Biennial

[1] Each vintage under the Sub 1032 Mechanism is referred to by the calendar year of its respective rate period (e.g., Vintage 2019).

Determination of Avoided Cost Rates as of December 31 of the year immediately preceding the annual DSM/EE rider filing date. New Paragraphs 23B through 23D address the steps that will be taken if specific DSM/EE programs continue to produce Total Resource Cost (TRC) test results less than 1.00 for an extended period. For any program that initially demonstrates a TRC of less than 1.00, the Company shall include in its annual DSM/EE rider filing a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program. If a program demonstrates a prospective TRC of less than 1.00 in a second DSM/EE rider proceeding, the Company shall include a discussion of what actions it has taken to improve cost effectiveness. If a program demonstrates a prospective TRC of less than 1.00 in a third DSM/EE rider proceeding, the Company shall terminate the program effective at the end of the year following the DSM/EE rider order, unless otherwise ordered by the Commission.

The Sub 1032 Mechanism, as revised by the Sub 1130 Order, is set forth in Maness Exhibit II and referred to herein as the "Mechanism."

On October 18, 2019, the Commission issued an Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice in Docket No. E-7, Sub 1192 (Sub 1192 Order). In the Sub 1192 Order, consistent with the requirements of N.C.G.S. § 62-133.9 and Commission Rule R8-68, the Commission approved the following DSM or EE programs or pilot programs to be offered to customers in 2020: Energy Assessments; EE Education; Energy Efficient Appliances and Devices; Residential Smart $aver EE; Multi-Family EE; MyHER; Income-Qualified EE and Weatherization; Power Manager; Non-Residential Smart $aver Energy Efficient Food Service Products; Non-Residential Smart $aver Energy Efficient HVAC Products; Non-Residential Smart $aver Energy Efficient IT Products; Non-Residential Smart $aver Energy Efficient Lighting Products; Non-Residential Smart $aver Energy Efficient Process Equipment Products; Non-Residential Smart $aver Energy Efficient Pumps and Drives Products; Non-Residential Smart $aver Custom; Non-Residential Smart $aver Custom Energy Assessments; PowerShare; PowerShare Call Option (canceled effective January 31, 2018); Small Business Energy $aver; Smart Energy in Offices (canceled effective June 30, 2018); EnergyWise for Business; and Non-Residential Smart $aver Performance Incentive. The Commission concluded that the Company's portfolio of DSM and EE programs was overall cost effective and eligible for inclusion in Rider 11. Pursuant to Paragraph 19 of the Sub 831 Mechanism, the Commission determined that the Income-Qualified EE and Weatherization Program – Low-Income does not have to meet the TRC or Utility Cost Test (UCT) to be eligible for inclusion in the Company's portfolio because of the exception for low income and other non-cost-effective programs with similar societal benefits.

The Commission accepted the EM&V reports filed as Evans Exhibits A, D, E, F, G, H, I, J, K, and L and considered them complete for purposes of calculating program impacts.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

Decision

Based upon consideration of DEC's Application, the pleadings, the testimony and exhibits received into evidence at the hearing, the parties' briefs, and the record as a whole, the Commission now 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. The Commission has jurisdiction over this Application pursuant to the Public Utilities Act. The Commission finds that it has the authority to consider and approve or modify the specific recovery of costs and incentives the Company is seeking in this docket.

3. For purposes of this proceeding, DEC has requested approval of costs and incentives related to the following DSM/EE programs to be included in Rider 12: Energy Assessment Program; EE Education Program; Energy Efficient Appliances and Devices Program; Residential Smart $aver EE Program; Multi-Family EE Program; My Home Energy Report Program; Income-Qualified EE and Weatherization Program; Power Manager Load Control Service Program; Non-Residential Smart $aver Energy Efficient Food Service Products Program; Non-Residential Smart $aver Energy Efficient HVAC Products Program; Non-Residential Smart $aver Energy Efficient IT Products Program; Non-Residential Smart $aver Energy Efficient Lighting Products Program; Non-Residential Smart $aver Energy Efficient Process Equipment Products Program; Non-Residential Smart $aver Energy Efficient Pumps and Drives Products Program; Non-Residential Smart $aver Custom Incentive and Energy Assessment Program; PowerShare; Small Business Energy Saver Program; EnergyWise for Business; and Non-Residential Smart $aver Performance Incentive Program.

4. Pursuant to Paragraph 19 of the Mechanism, the Income-Qualified EE and Weatherization Program is not required to pass the TRC or UCT tests to be eligible for inclusion in the Company's portfolio.

5. The Residential Smart $aver EE Program has failed to demonstrate a prospective TRC result greater than 1.0 in the current proceeding and in the previous five rider proceedings.[1]

6. The Food Service and the Information Technology measures of the Non-residential Smart $aver Program are not currently cost effective under the TRC test; however, these are only two measures of a larger program, and no party recommended that the Company take action.

7. To sustain the benefit that low income customers and multi-family residences obtained from A-line bulbs, the Company should continue to provide A-line bulbs to low income

[1] The last time the Company forecasted a TRC score above 1.0 for this program was in Docket No. E-7, Sub 1050, filed in March of 2014.

customers and continue to replace inefficient lighting through its multi-family direct install program.

8. The Company's proposed Grid Improvement Plan (GIP) has the potential to impact the cost effectiveness of the Company's DSM/EE programs.

9. For purposes of inclusion in Rider 12, the Company's portfolio of DSM and EE programs is cost effective.

10. The EM&V reports filed as Evans Exhibits A, B, C, D, and E, are acceptable for purposes of this proceeding and should be considered complete for purposes of calculating program impacts.

11. Pursuant to the Commission's Sub 938 Second Waiver Order and the Sub 1032 Order, the rate period for purposes of this proceeding is January 1, 2021 through December 31, 2021.

12. Rider 12 includes EMF components for Vintage 2019 DSM and EE programs. Consistent with the Sub 938 Second Waiver Order and the Sub 1032 Order, the test period for these EMF components is the period from January 1, 2019 through December 31, 2019 (Vintage 2019).

13. DEC's proposed rates for Rider 12 are comprised of both prospective and EMF components. The prospective components include factors designed to collect estimated program costs and PPI for the Company's Vintage 2021 DSM and EE programs, as well as estimated NLR for the Company's Vintage 2018-2021 EE programs. The EMF components include the whole or partial true-up of Vintage 2019 program costs, NLR, and PPI, as well as whole or partial true-ups of NLR and PPI for Vintage Year 2018, and NLR for Vintages 2016 and 2017. DEC, with the exception of billing factors affected by Finding of Fact 14, and as reflected in the testimony and exhibits of Company witnesses Miller and Evans, has appropriately calculated the components of Rider 12 to reflect the Commission's findings and conclusions in this Order, as well as the Commission's findings and conclusions as set forth in the Sub 1032 Order, as revised by the Sub 1130 Order.

14. The Company included a 17% reserve margin adder when calculating the avoided capacity costs for purposes of the Company's Vintage 2021 DSM and EE programs.

15. The Company's seasonal allocation of avoided capacity value is consistent with the Commission's most recent avoided cost proceeding and is appropriate.

16. The reasonable and prudent Rider 12 billing factor for residential customers[1] submitted by DEC must be recalculated by the Company due to the Commission's Finding of Fact 14.

17. The reasonable and prudent Rider 12 Vintage 2021 EE prospective billing factor for nonresidential customers not opting out of Vintage 2021 of the Company's EE programs is 0.3495 cents per kWh, which, as is the case for all the other billing factors stated in these findings of fact, includes the regulatory fee.

18. The reasonable and prudent Rider 12 Vintage 2021 DSM prospective billing factor for nonresidential customers not opting out of Vintage 2021 of the Company's DSM programs is 0.1200 cents per kWh.

19. The reasonable and prudent Rider 12 Vintage 2020 prospective EE billing factor for nonresidential customers participating in Vintage 2020 of the Company's EE programs (or those not participating, but neither (a) explicitly opting out of Vintage 2020 during the annual enrollment period for that vintage, nor (b) opting out of Vintage 2021) is 0.0612 cents per kWh.

20. The reasonable and prudent Rider 12 Vintage 2019 prospective EE billing factor for nonresidential customers participating in Vintage 2019 of the Company's EE programs (or those not participating, but neither (a) explicitly opting out of Vintage 2019 during the annual enrollment period for that vintage, nor (b) opting out of Vintage 2021) is 0.0687 cents per kWh.

21. The reasonable and prudent Rider 12 Vintage 2018 prospective EE billing factor for nonresidential customers participating in Vintage 2018 of the Company's EE programs (or those not participating, but neither (a) explicitly opting out of Vintage 2018 during the annual enrollment period for that vintage, nor (b) opting out of Vintage 2021) is 0.0137 cents per kWh.

22. The reasonable and prudent Rider 12 Vintage 2019 EE EMF billing factor for nonresidential customers participating in Vintage 2019 of the Company's EE programs (or those not participating, but neither (a) explicitly opting out of Vintage 2019 during the annual enrollment period for that vintage, nor (b) opting out of Vintage 2021) is (0.0225) cents per kWh.

23. The reasonable and prudent Rider 12 Vintage 2019 DSM EMF billing factor for nonresidential customers participating in Vintage 2019 of the Company's DSM programs (or those not participating, but neither (a) explicitly opting out of Vintage 2019 during the annual enrollment period for that vintage, nor (b) opting out of Vintage 2021) is 0.0019 cents per kWh.

24. The reasonable and prudent Rider 12 Vintage 2018 EE EMF billing factor for nonresidential customers participating in Vintage 2018 of the Company's EE programs (or those not participating, but neither (a) explicitly opting out of Vintage 2018 during the annual enrollment period for that vintage, nor (b) opting out of Vintage 2021) is (0.0049) cents per kWh.

[1] The residential billing factor applicable to all residential customers is the sum of the residential prospective and residential true-up factors for the applicable vintage years.

25. The reasonable and prudent Rider 12 Vintage 2018 DSM EMF billing factor for nonresidential customers participating in Vintage 2018 of the Company's DSM programs (or those not participating but neither (a) explicitly opting out of Vintage 2018 during the annual enrollment period for that vintage, nor (b) opting out of Vintage 2021) is (0.0014) cents per kWh.

26. The reasonable and prudent Rider 12 Vintage 2017 EE EMF billing factor for nonresidential customers participating in Vintage 2017 of the Company's EE programs (or those not participating, but neither (a) explicitly opting out of Vintage 2017 during the annual enrollment period for that vintage, nor (b) opting out of Vintage 2021) is 0.0342 cents per kWh.

27. The reasonable and prudent Rider 12 Vintage 2017 DSM EMF billing factor for nonresidential customers participating in Vintage 2017 of the Company's DSM programs (or those not participating, but neither (a) explicitly opting out of Vintage 2017 during the annual enrollment period for that vintage, nor (b) opting out of Vintage 2020) is 0.0000 cents per kWh.

28. The reasonable and prudent Rider 12 Vintage 2016 EE EMF billing factor for nonresidential customers participating in Vintage 2016 of the Company's EE programs (or those not participating, but neither (a) explicitly opting out of Vintage 2016 during the annual enrollment period for that vintage, nor (b) opting out of Vintage 2021) is 0.0193 cents per kWh.

29. The reasonable and prudent Rider 12 Vintage 2016 DSM EMF billing factor for nonresidential customers participating in Vintage 2016 of the Company's DSM programs (or those not participating, but neither (a) explicitly opting out of Vintage 2016 during the annual enrollment period for that vintage, nor (b) opting out of Vintage 2021) is (0.0001) cents per kWh.

30. DEC should continue to leverage its collaborative stakeholder meetings (Collaborative) to work with stakeholders to garner meaningful input regarding potential portfolio enhancement and program design.

31. The Company should continue the frequency of the Collaborative meetings so that the combined DEC/Duke Energy Progress, LLC (DEP) Collaborative meets every two months.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

The evidence and legal bases in support of these findings and conclusions can be found in the Application, the pleadings, the testimony, and the exhibits in this docket, as well as in the statutes, case law, and rules governing the authority and jurisdiction of this Commission. These findings are informational, procedural, and jurisdictional in nature.

N.C.G.S. § 62-133.9 authorizes the Commission to approve an annual rider, outside of a general rate case, for recovery of reasonable and prudent costs incurred in the adoption and implementation of new DSM and EE measures, as well as appropriate rewards for adopting and implementing those measures. Similarly, Commission Rule R8-68 provides, among other things, that reasonable and prudent costs of new DSM or EE programs approved by the Commission shall be recovered through the annual rider described in N.C.G.S. § 62-133.9 and Commission

Rule R8-69. The Commission may also consider in the annual rider proceeding whether to approve any utility incentive (reward) pursuant to N.C.G.S. § 62-133.9(d) (2) a through c.

Commission Rule R8-69 outlines the procedure whereby a utility applies for and the Commission establishes an annual DSM/EE rider. Commission Rule R8-69(a)(2) defines DSM/EE rider as "a charge or rate established by the Commission annually pursuant to N.C.G.S. § 62-133.9(d) to allow the electric public utility to recover all reasonable and prudent costs incurred in adopting and implementing new demand-side management and energy efficiency measures after August 20, 2007, as well as, if appropriate, utility incentives, including net lost revenues." Commission Rule R8-69(c) allows a utility to apply for recovery of incentives for which the Commission will determine the appropriate ratemaking treatment.

N.C.G.S. § 62-133.9, along with Commission Rules R8-68 and R8-69, establish a procedure whereby an electric public utility files an application in a unique docket for the Commission's approval of an annual rider for recovery of reasonable and prudent costs of approved DSM and EE programs. The procedure outlined in N.C.G.S. § 62-133.9 and Commission Rules R8-68 and R8-69 also allow an electric public utility to recover appropriate utility incentives, potentially including "appropriate rewards based on capitalization of a percentage of avoided costs achieved by demand-side management and energy efficiency measures." Consistent with this provision, as well as the Commission-approved Mechanism, the Company filed an application for approval of such annual rider, designated by DEC as Rider 12. The cost recovery and utility incentives the Company seeks through Rider 12 are based on the Company recovering DSM/EE program costs, NLR, and a PPI incentive related to the DSM and EE programs approved in the Sub 1032 Order, and those programs approved following the Sub 1032 Order. Recovery of these costs and utility incentives is also consistent with N.C.G.S. § 62-133.9, Rule R8-68, and Rule R8-69. Therefore, the Commission concludes that it has the authority to consider and approve the cost recovery and incentives the Company is seeking in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding and conclusion can be found in DEC's Application, the testimony and exhibits of Company witnesses Evans and Miller, the testimony of Public Staff witness Williamson, and various Commission orders.

DEC witnesses Miller's and Evans's testimony and exhibits show that the Company's request for approval of Rider 12 is associated with the Sub 1032 portfolio of programs, as well as the programs approved by the Commission after the Sub 1032 Order. The direct testimony and exhibits of DEC witness Evans listed the applicable DSM/EE programs as follows: Energy Assessments Program; EE Education Program; Energy Efficient Appliances and Devices; Residential Smart $aver EE Program; Multi-Family EE Program; My Home Energy Report; Income-Qualified EE and Weatherization Program; Power Manager Load Control Service Program; Non-Residential Smart $aver Energy Efficient Food Service Products Program; Non-Residential Smart $aver Energy Efficient HVAC Products Program; Non-Residential Smart $aver Energy Efficient IT Products Program; Non-Residential Smart $aver Energy Efficient Lighting Products Program; Non-Residential Smart $aver Energy Efficient Process Equipment

Products Program; Non-Residential Smart $aver Energy Efficient Pumps and Drives Products Program; Non-Residential Smart $aver Custom Incentive Program; Non-Residential Smart $aver Custom Energy Assessments Program; PowerShare Non-Residential and Load Curtailment Program; PowerShare Call Option Program[1]; Small Business Energy Saver; Smart Energy in Offices Program[2]; EnergyWise for Business Program; and Non-Residential Smart $aver Performance Incentive Program. (Tr. 59-60.)[3]

In his affidavit, Public Staff witness Williamson also listed the DSM/EE programs for which the Company seeks cost recovery, and noted that each of these programs has received approval as a new DSM or EE program and is eligible for cost recovery in this proceeding under N.C.G.S. § 62-133.9. He also noted the Commission approved DEC's modifications to the Residential Energy Saver and Residential Neighborhood Energy Saver program since the prior Rider proceeding in Docket No. E-7, Sub 1192. (*Id.* at 236-38.)

Thus, the Commission finds and concludes that each of the programs listed by witnesses Evans and Williamson has received Commission approval as a new DSM or EE program and is, therefore, eligible for cost recovery in this proceeding under N.C.G.S. § 62-133.9.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-9

The evidence for these findings and conclusions can be found in the testimony and exhibits of Company witness Evans, the testimony and exhibits of Public Staff witnesses Williamson and Maness, and the testimony of NC Justice, *et al.*, witness Bradley-Wright.

DEC witness Evans testified that the Company reviewed the portfolio of DSM/EE programs and performed prospective analyses of each of its programs and the aggregate portfolio for the Vintage 2021 period, the results of which are incorporated in Evans Exhibit No. 7. (Tr. 61.) DEC's calculations indicate that, except for the Income-Qualified EE and Weatherization Program (which was not cost-effective at the time of Commission approval), the Residential Smart $aver EE Program, which is continuing its transformation to an all referral channel, and elements of the Non-Residential Smart $aver Program, the aggregate portfolio continues to be cost-effective. Witness Evans testified that there is no reason to discontinue any of DEC's programs, but the Company will continue to examine its programs for potential modifications to increase their effectiveness, regardless of current cost-effectiveness results. (*Id.*)

[1] This program was canceled effective January 31, 2018, pursuant to the Sub 1130 Order.

[2] This program was canceled effective June 30, 2018, pursuant to the Commission's February 7, 2018 order in Docket No. E-7, Sub 961.

[3] All transcript references in this Order are to Volume 2 of the transcript. Volume 1 is the transcript of the public witness hearing.

NC Justice Center, *et al.*, witness Bradley-Wright testified that DEC's DSM/EE portfolio is cost-effective, with the value of DEC's DSM/EE programs significantly exceeding the costs and delivering strong financial value to customers. (Tr. 356)

Public Staff witness Williamson stated in his testimony that the Public Staff reviewed DEC's calculations of cost effectiveness under each of the four standard cost effectiveness tests: UCT, TRC, Participant test, and RIM test. Tr. 240) The Public Staff also compared the cost effectiveness test results in previous DSM/EE proceedings to the current filing and developed a trend of cost effectiveness that serves as the basis for the Public Staff's recommendation of whether a program should be terminated. (Tr. 241-42)

Witness Williamson testified that while many programs continue to be cost effective, the TRC and UTC test scores as filed by the Company for all programs have a natural ebb and flow, mainly due to the changes in avoided cost rate determinations. (*Id.* at 242.) He stated that the decreasing cost effectiveness is also partially attributable to anticipated unit savings being lower than expected as determined through EM&V of the programs. Also, as programs mature, baseline standards increase, or avoided cost rates decrease, and it becomes more difficult for a program to produce cost effective savings. Witness Williamson further remarked that, in contrast, some programs, have experienced greater than expected participation, which typically results in greater savings per unit cost and increases cost-effectiveness. (*Id.*)

Witness Williamson identified three areas of concern with the Company's portfolio: lighting-related measures; grid improvement plans (GIP) and the Residential Smart Saver EE program's Referral Channel.

1. Lighting

With respect to the lighting-related measures, witness Williamson recalled that the Public Staff had previously noted several trends related to transformation of the EE lighting market in North Carolina resulting from the growing accessibility of non-specialty light emitting diode (LED) lighting. Based on those trends, he predicted that LED lighting will likely become the baseline standard for general service bulb technologies by January 2020, thereby decreasing the savings from any EE program that includes general service bulb technologies. (*Id.* at 246-47.)

Witness Williamson further testified about how changes in the implementation of lighting standards may impact DEC's EE programs going forward. He recounted that on January 19, 2017, the United States Department of Energy (DOE), published final rules adopting a revised definition for general service lamp (GSL), and general service incandescent lamp (GSIL); however, on February 11, 2019, the DOE issued a notice of proposed rulemaking and request for comment that potentially could have led to withdrawal of the then currently approved language on GSL and GSIL. On September 5, 2019, the DOE published a notice of proposed determination in which it initially determined the energy conservation standards for GSILs do not need to be amended. On December 27, 2019, the DOE published a final determination in which it responded to comments received and determined that amending energy conservation standards would not be economically justified. (*Id.* at 247.)

Witness Williamson testified that North Carolina's lighting market was transforming more quickly than initially recognized because of changes to the federal lighting standards since 2007 and customer preference for LEDs. He recommended that, because of these factors, LED lighting should be considered the baseline standard for general service bulb technologies. He further testified that "market transformation" or routine adoption of EE measures had occurred in the lighting market. As a result, the Public Staff agrees with the Company's approach to focus on specialty LED bulb technologies. He concluded, however, by recommending that, beginning in 2021, the Commission consider only specialty LED lighting for recognition as energy efficiency. (*Id.* at 249.)

Company witness Evans opposed Public Staff witness Williamson's recommendation because, despite changes in the efficiency lighting market, the Company still sees an ongoing need for non-specialty energy efficient A-line bulbs for low-income and multifamily residences. Witness Evans reported that, to allow those customers to share in the benefits of energy efficiency lighting, the Company intends to continue providing A-line bulbs to low-income customers through its direct install Neighborhood Energy Saver Program and through outlets such as Good Will, Dollar General, and Habitat stores. Additionally, the Company intends to continue to replace inefficient lighting through its Multifamily direct install program. Future needs for these two customer groups will be monitored as independent EM&V studies for these programs determine their saturation. (*Id.* at 82-83.)

2. GIP

Public Staff witness Williamson also expressed concern with the impact of the Company's proposed GIP on its DSM/EE programs. He testified that the GIP would drive enhancements to capacity, data analytics/collection, and power flow capabilities on almost all of the circuits within its service territory. As more data analytics and technology enhancements are made to the Company's day-to-day operations, the base-level impacts and offerings of DSM/EE programs will be impacted. He stated that he believes the MyHER and DSM programs will be most impacted by the GIP proposal, as they rely heavily on data analytics and base level system capacity on the Transmission and Distribution (T&D) grid. He believes that as the Company deploys GIP, MyHER and the DSM programs will need to be re-evaluated to ensure that they remain cost-effective and to determine whether they have become standard operating procedures. (*Id.* at 250-51.)

With respect to MyHER, witness Williamson explained that the program relies on the collection of individual customers' data, and then analyzes that data in relation to similar nearby customers. As part of the GIP, the Company has been deploying Advanced Metering Infrastructure (AMI) throughout its service territory, which is expected to, among other things, provide customers with direct access to their interval usage data through the use of a Smart Meter Usage App. Witness Williamson stated that the services and access to data provided by the meters will be duplicative of the data provided under the MyHER program, with the exception of the energy efficiency tips offered through the MyHER report. He recommended that the Commission require DEC to assess the costs and benefits of continuing to offer the MyHER program, versus providing the same comparison and tips through another channel. (*Id.* at 251-53.)

Witness Williamson also testified that because the Company's DSM program relies on the level of system demand that is on the grid at the time that the particular DSM program is called upon by system operations, the Company's plan to build grid infrastructure to enable Integrated Volt/Var controls (IVVC) will reduce the Company's demand savings from the Company's DSM programs. Upon questions by Commissioner Brown-Bland, witness Williamson stated that regardless of "whether or not it could be captured in the EM&V," he reviewed trends, and the GIP was changing the utility's business model. For this reason, he wanted to ensure that savings reflect only the impact associated with the DSM and EE programs. (*Id.* at 296-97.) Thus, witness Williamson recommended that the Commission direct the Company to: (1) analyze GIP to explain how it will affect DSM/EE program performance to produce peak demand and energy savings; (2) explain in the next rider proceeding how the Company will distinguish between peak demand and energy savings associated with the GIP program on the one hand and DSM and EE programs on the other; and (3) provide a list of GIP projects that have been implemented, indicating how those projects have affected performance of the Company's DSM/EE portfolio if at all, and be prepared to discuss any impacts the GIP has had on the day-to-day systems operations, as well as customer expectations for utility service in general, and the availability of customer data. (*Id.* at 254-56.)

Company witness Evans responded to the Public Staff's GIP concerns by testifying on rebuttal that the Company had already provided voluminous data, analyses, and general information about the Companies' GIP program, including IVVC, as part of the ongoing general rate cases in Docket Nos. E-7, Sub 1214, and E-2, Sub 1219. He affirmed that the Company was not opposed to reporting information related to IVVC, but the additional analysis recommended by witness Williamson was unnecessary. He further confirmed that any influence or interaction between GIP and the DSM/EE programs will be evaluated and captured in the existing reporting protocols. Additionally, witness Evans confirmed that the GIP program will not be in place until 2024 (*Id.* at 130.) Furthermore, witness Evans cautioned that integrating additional GIP status reporting into separate DSM/EE proceedings could lead to confusion as the programs are separate initiatives designed to achieve clearly defined, distinguishable goals. (*Id.* at 83-84.)

With respect to witness Williamson's recommendation that the Company reassess its MyHER program in light of the smart energy usage app and smart meter installation, witness Evans testified that MyHER is designed to engage the customers and includes a motivational aspect for customers resulting from the normative comparison of a customer's usage to their peers that the mere provision of energy usage information to customers through the app does not provide. Moreover, customers have had access to their usage data for years, albeit without as much precision, but MyHER has continued to provide significant benefits to DEC's customer base. (*Id.* at 134, 158-59.)

3. Residential Smart $aver EE Program's Referral Channel

Although Public Staff witness Williamson testified that he did not believe that DEC had violated any Commission rules or flexibility guidelines addressing how program modifications should be addressed, he remarked on the Company's Smart $aver EE program's use of a referral channel to offset some of the costs associated with the program and to bolster the cost-effectiveness of it. On September 11, 2017, the Commission approved the conversion of the program to include additional household related measures, as well as an online store. Witness Williamson testified that the referral channel has been expanded to include a variety of items beyond "the original focus" of HVAC equipment-related contractor referrals. The Company's website provides the contractor referral information under the marketing name "Find it Duke." The services listed include heating and air conditioning, insulation, plumbing, electrical, pool, solar, and tree removal. (*Id.* at 261-62.) Witness Williamson explained that all the revenues that DEC receives from contractors participating in the referral channel are used to offset program costs for the benefit of the Smart $aver program and DEC's customers. This includes revenues from solar and tree service contractors, which at present represents only a very small portion of the overall revenues received. (*Id.* at 262-63.) Public Staff witness Maness also testified that the referral service may include referral services for non-regulated services to be performed by third parties; however, witness Maness did not make any recommendations about this possibly non-regulated component of the referral service. (*Id.* at 330.) Witnesses Williamson and Maness both concluded by indicating that the Public Staff will continue to discuss the matter of the referral channel with the Company and, as part of those discussions, address whether the flexibility guidelines should be revised to address this type of program modification in the future. (*Id.* at 263, 330.)

SUMMARY OF PUBLIC STAFF TESTIMONY AND RECOMMENDATONS ON EE PROGRAMS

Neighborhood Energy Saver Program (NES, formerly Income-Qualified EE and Weatherization Program)

Witness Evans testified that the Income-Qualified EE and Weatherization Program, which was not cost effective at the time of Commission approval, is not projceted to be cost-effective for the Vintage 2021 period. (*Id.* at 61.)

Pursuant to Paragraph 19 of the Mechanism (which provides an exception for low income programs and other non-cost-effective programs with similar societal benefits), the NES program is not required to pass the TRC or UCT tests to be eligible for inclusion in the Company's portfolio. Accordingly, the Commission finds and concludes that no further action by the Company is required with respect to this program.

Residential Smart $aver

In his direct testimony, DEC witness Evans indicated that the Residential Smart $aver EE program is not projected to be cost effective for the Vintage 2021 period. (*Id.* at 61.) He added that during 2019, the Company implemented several changes to the program, including the continued transformation to an all referral channel. (*Id.* at 62.) He further testified that there are no reasons to discontinue any of DEC's programs, and that the Company continues to examine its programs for potential modifications to increase their effectiveness, regardless of the current cos-effectiveness test results. (*Id.* at 61.)

As fully discussed above, Public Staff witness Williamson testified that the Company has recently expanded the scope of the Smart $aver referral channel to include a variety of items and services beyond its original focus on HVAC equipment-related contractor referrals, and that the referral channel now also provides customers with contractor referrals related to rooftop solar systems, plumbing, and tree removal services. (*Id.* at 261-63.) Witnesses Williamson and Maness stated that the Public Staff will continue to discuss the matter of the referral channel with the Company. (*Id.* at 263, 330.)

The Commission agrees with Public Staff witness Williamson that the Company has not violated the flexibility guidelines or any Commission rules or orders in implementing the Residential Smart $aver EE Program's referral channel. The Commission directs the Public Staff and the Company to continue to discuss the matter as recommended by witness Williamson.

The Commission notes that the Residential Smart $aver EE program has failed to demonstrate a prospective TRC result greater than 1.0 in the current proceeding and in the last five rider proceedings: Docket Nos. E-7, Subs 1073, 1105, 1130, 1164, and 1192. Paragraph 23 of the Mechanism requires the Company, in each annual DSM/EE cost recovery filing, to perform prospective cost-effective test evaluations for each of its approved DSM and EE programs. Pursuant to Paragraph 23B of the Mechanism, when a program initially demonstrates a prospective TRC of less than 1.0, the Company must include a discussion in its annual DSM/EE rider proceeding concerning actions being taken to maintain or improve cost-effectiveness, or, alternatively, plans to terminate the program. Pursuant to Paragraph 23C, if a program demonstrates a prospective TRC of less than 1.0 in a second DSM/EE rider proceeding, the Company must include a discussion in its annual filing concerning what actions it has taken to improve cost-effectiveness. Pursuant to Paragraph 23D, if a program demonstrates a prospective TRC of less than 1.0 in a third DSM/EE rider proceeding, the Company must terminate the program, unless otherwise ordered by the Commission. In its January 7, 2019 Order in Docket Nos. E-7 Sub 1032 and E-7 Sub 1164, the Commission exercised its discretion to forego terminating the Residential Smart $aver EE program and, instead, approved modifications to the program.

The Commission determines that it is appropriate at this time to allow continuation of the Residential Smart $aver EE program in order to see whether the program modifications approved in Sub 1164 will increase the cost effectiveness of the program during 2021. In addition, because the Residential Smart $aver EE program has now demonstrated a prospective TRC of less than 1.0 in a sixth consecutive DSM/EE rider proceeding, the Commission is of the opinion that it may be necessary in DEC's next DSM/EE rider proceeding to determine whether there are additional steps that can be taken to improve the cost effectiveness of the program, or whether the program should be terminated.

Based on the foregoing, the Commission determines that no changes are required to the Company's Residential Smart $aver EE program at this time. However, the Commission also finds and concludes that if the program continues to demonstrate a prospective TRC result of less than 1.0 for the Vintage 2022 forecast in DEC's next DSM/EE rider proceeding, the Commission will order DEC in that rider proceeding to terminate the program unless DEC can establish by substantial evidence that there are additional modifications to the program that will improve the cost effectiveness of the program.

Non-Residential Smart $aver

In his direct testimony, DEC witness Evans indicated that two elements (measures) of the Non-Residential Smart $aver program—Food Service and Information Technology—are not cost effective. Witness Evans testified, however, that it would not be appropriate to discontinue these measures of the Non-Residential Smart $aver Program. He stated that these measures are "integral" for ensuring that a robust portfolio of prescriptive offerings is available for the Company's non-residential customers, and that these Food Service and Information Technology are merely measure categories within a much larger program. He explained that the TRC score for the prescriptive portion of the Non-Residential Smart $aver Program is 2.05, and the TRC score for the Non-Residential Smart $aver Program as a whole is 1.71. (*Id.* at 61-62.)

Based on the foregoing, the Commission finds and concludes that the Company is not required to take any action with respect to these two measures of the Non-Residential Smart $aver Program at this time.

Conclusions

Based upon the foregoing, the Commission concludes that for purposes of inclusion in Rider 12, except for the Income-Qualified EE and Weatherization Program (which was not cost effective at the time of Commission approval), the Residential Smart $aver EE Program, which is continuing its transformation to an all referral channel, and elements of the Non-Residential Smart $aver Program, the aggregate portfolio continues to be cost effective. Because the Commission is concerned that low income and multifamily residences continue to share in the benefits of energy efficient lighting, it declines to approve the Public Staff's recommendation that it consider only specialty LED lighting for recognition as energy efficiency in these proceedings. Instead, to sustain the benefit that low income customers and multifamily residences obtain from A-line bulbs, the Commission directs the Company to continue to provide A-line bulbs to low income customers through its direct install Neighborhood Energy Saver program and to provide them through outlets such as Good Will, Dollar General, and Habitat stores. The Commission further approves the Company's proposal to continue replacing inefficient lighting through its Multifamily direct install program in instances where the Company is certain that inefficient lighting options are being replaced. The Company should continue to closely monitor the future needs of low income and multifamily residences as independent EM&V studies for these programs determine their saturation with standard high efficiency lighting.

With respect to witness Williamson's recommendations concerning the GIP, the Commission finds and concludes that the potential impacts of the Company's proposed GIP on the cost effectiveness of the Company's DSM/EE programs warrants further examination. The Commission has received and reviewed voluminous evidence on GIP implementation in the pending general rate case in Docket No. E-7 Sub 1214, especially through the direct and rebuttal testimony of Jay W. Oliver (rebuttal testimony filed March 4, 2020). Additional status reporting in the DSM/EE docket will only duplicate reporting done in other proceedings and complicate the already extensive reporting requirements in the DSM/EE proceedings. As witness Evans proposed, the more effective method for conveying GIP impacts on the DSM/EE portfolio for purposes of the DSM/EE rider proceedings is through EM&V reporting protocols that are already submitted in these proceedings.

With respect to the question of whether the additional analyses recommended by witness Williamson will be adequately covered by EM&V analyses, the Commission is not persuaded that a yearly analysis of any impacts on cost effectiveness will be essential to evaluating the Company's DSM/EE portfolio during each year's rider proceeding, and concludes that the existing EM&V reporting protocol is sufficient. The Commission further concludes that some information concerning the status of its GIP initiatives and their effects on DSM/EE programs could be helpful in its DSM/EE rider proceedings and, therefore, finds that the Company shall in the next rider proceeding (1) explain how the Company will distinguish peak demand and energy savings between GIP and DSM and EE programs; and (2) provide a list of GIP projects that have been implemented and explain how those projects have affected the performance of the Company's DSM/EE portfolio, if at all. Requiring DEC to perform an analysis explaining how GIP will affect the performance of individual DSM/EE programs and their ability to produce peak demand and energy savings, and file the report with the Commission in the current docket by January 1, 2021 is premature and not necessary at this time.

The Commission recognizes that there is a distinction between customers' receiving additional and more precise data about their energy usage from smart meters or from the smart meter usage app, which do not act as energy efficiency programs, and participating in a utility program, like MyHER, which engages customers through normative comparison of their usage to that of their peers and empowers customers to act on that data. Therefore, the Commission declines to accept the Public Staff's request to direct the Company to reassess its successful MyHER program at this time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence in support of this finding and conclusions can be found in the testimony and exhibits of DEC witness Evans and the testimony of Public Staff witness Williamson.

DEC witness Evans testified regarding the EM&V process, activities, and results presented in this proceeding. He explained that the EMF component of Rider 12 incorporates actual customer participation and evaluated load impacts determined through EM&V and applied pursuant to the EM&V Agreement approved by the Commission in its Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice, issued November 8, 2011 in Docket No. E-7, Sub 979 (EM&V Agreement). In addition, actual participation and evaluated load impacts are used prospectively to update estimated NLR. (Tr., 68.) In this proceeding, the Company submitted as exhibits to witness Evans' testimony detailed, completed EM&V reports or updates for the following programs: Income-Qualified EE and Weatherization Program (Neighborhood Energy Saver) Program Evaluation Report, 2017 (Evans Exhibit A); My Home Energy Report Program Evaluation, 2017-2018 (Evans Exhibit B); Power Share Program Evaluation, 2018 (Evans Exhibit C); Energy Efficiency Education in Schools Evaluation Report, 2017-2018 (Evans Exhibit D); Smart $aver Evaluation Report, 2016-2017 (Evans Exhibit E). (*Id.* at 55-56.)

In his testimony, Public Staff witness Williamson testified that he had investigated and reviewed the EM&V reports filed in this proceeding, labeled as Evans Exhibits A through E, and that the reports should be considered complete. (*Id.* at 264-68.). He further testified that he had confirmed that the Company's calculations had incorporated the verified savings of the various EM&V reports. (*Id.* at 269.) With respect to Evans Exhibit A, which presented the evaluation of the performance of the Neighborhood Energy Saver (NES) program, he stated that the results apply to program participation from June 30, 2018 through the end of the sampling period associated with the next evaluation. Witness Williamson further stated that the evaluator of the NES program used an engineering analysis that relied upon information from other sources to determine program savings, and so a billing analysis was not done. Witness Williamson did not dispute that the engineering analysis was an appropriate analytical approach for the NES program; however, he preferred a billing analysis. (*Id.* at 265-66.)

Witness Williamson also raised an issue with respect to the net-to-gross ratio (NTGR). Again, he did not dispute the use of the engineering analysis assuming an NTGR of 1.0, indicating that was standard practice for income-qualified programs; however, he noted that lighting accounted for 38% of the program's gross savings and that there had been significant changes in the lighting market in recent years. Witness Williamson found Evans Exhibit A acceptable for purposes of verifying the NES program savings. He recommended, however, that the next evaluation of NES rely on a billing analysis for assessing the savings attributable to NES. He reported that the Company agreed to initiate the next analysis very soon. (*Id.* at 265-66.)

Witness Williamson also expressed concern about cases offering similar or identical measures across multiple programs, but having those measures evaluated by different contractors using different assumptions. Witness Williamson recommended that in the future DEC work to ensure that these measures be evaluated consistently. Otherwise, the Company should justify the differences. Witness Williamson concluded that the EM&V reports filed in this proceeding should be accepted as complete. (*Id.* at 268.)

No party contested the EM&V information submitted by the Company. The Commission therefore finds that the EM&V reports filed as Evans Exhibits A, B, C, D, and E are acceptable for purposes of this proceeding and should be considered complete for purposes of calculating program impacts.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 11

The evidence in support of this finding and conclusion can be found in the Sub 938 Second Waiver Order, the Sub 1032 Order, the testimony of Company witnesses Miller and Evans, and the testimony of Public Staff witness Maness. The rate period and the scope of the EMF components of Rider 12 are consistent with the Commission's rulings in the Sub 938 Second Waiver Order and the Sub 1032 Order and are uncontested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 – 29

The evidence in support of these findings and conclusions can be found in the Sub 831 Order, Sub 831 Found Revenues Order, Sub 938 Waiver Order, Sub 938 Second Waiver Order, Sub 979 Order, Sub 1032 Order, and Sub 1130 Order, as well as in the Company's Application, the direct and supplemental testimony and exhibits of Company witness Miller, the direct and rebuttal testimony and exhibits of witness Evans, the rebuttal testimony of Company witness Duff, the direct and supplemental testimony and exhibits of Public Staff witnesses Maness and Williamson, and the direct testimony of Public Staff witness Hinton.

On February 25, 2020, DEC filed its Application seeking approval of Rider 12, which includes the formula for calculation of Rider EE, as well as the proposed billing factors to be effective for the 2021 rate period. Company witness Miller testified that the methods by which DEC has calculated its proposed Rider EE are consistent with the Sub 1032 Stipulation and the Mechanism approved in the Sub 1032 Order, as revised by the Sub 1130 Order. (Tr. 19.)

Witness Miller provided an overview of the Mechanism, which is designed to allow the Company to collect revenue equal to its incurred program costs[1] for a rate period, plus a PPI based on shared savings achieved by the Company's DSM and EE programs, and to recover NLR for EE programs only. (*Id.* at 19-23.) Witness Miller explained that the PPI is calculated by multiplying the net dollar savings achieved by the system portfolio of DSM and EE programs by a factor of 11.5%. (*Id.* at 24.) The system amount of PPI is then allocated to North Carolina retail customer classes to derive customer rates. (*Id.* at 25.) Company witness Evans explained that the calculation of the PPI is based on avoided cost savings, net of program costs, achieved through the implementation of the Company's DSM and EE programs. (*Id.* at 70-75.)

According to witness Miller, the Company may recover NLR associated with a particular vintage for a maximum of 36 months or the life of the measure, or until the implementation of new rates in a general rate case to the extent that the new rates are set to recover NLR. Witness Miller testified that for the prospective components of Rider EE, NLR are estimated by multiplying the portion of the Company's tariff rates that represents the recovery of fixed costs by the estimated North Carolina retail kilowatt (kW) and kWh reductions applicable to EE programs by rate schedule, and reducing this amount by estimated found revenues. (*Id.* at 25.) He further testified that the fixed cost portion of the tariff rates is calculated by deducting the recovery of fuel and variable operation and maintenance costs from the tariff rates, and that the NLR totals for residential and nonresidential customers are then reduced by North Carolina retail found revenues computed using the weighted average lost revenue rates for each customer class. (*Id.*) For the EMF components of Rider EE, NLR are calculated by multiplying the fixed cost portion of the tariff rates by the actual and verified North Carolina retail kW and kWh reductions applicable to EE programs by rate schedule, and reducing this amount by actual found revenues. (*Id.* at 26.)

[1] Rule R8-68(b)(1) defines "program costs" as all reasonable and prudent expenses expected to be incurred by the electric public utility, during a rate period, for adopting and implementing new DSM and EE measures previously approved pursuant to Rule R8-68.

Witness Miller also testified about the impact of the Commission's Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, issued on June 22, 2018 in Docket No. E-7, Sub 1146, the Company's last base rate case. (Sub 1146 Order). In that order, the Commission directed the Company to maintain all of its federal excess deferred income taxes resulting from passage of the federal Tax Cuts and Jobs Act (TCJA), in a regulatory liability account pending flow back of that liability to DEC's ratepayers with interest. The Company is to file its proposal to flow back the excess deferred taxes by June 22, 2021, or in its next general rate case, whichever is sooner. Witness Miller then confirmed that DEC intended to file a general rate case in 2019. At the time DEC filed for EE/DSM cost recovery in Rider 11, it was expected that the Commission would resolve the method to flow back EDIT to customers during the planned 2019 rate case, but the timing and methodology of that anticipated flowback has yet to be determined. Therefore, DEC incorporated a placeholder for the return of EDIT in Rider 11 to mitigate potential overcollection. Witness Miller explained that for Rider 11 only, the Company included a reduction of $10 million to Year 2020 lost revenues collected from each Vintage 2017 – 2020. She reported that this will be trued-up to actual EDIT impact on the lost revenue rate in the next DSM/EE rider filing after an order is issued in DEC's pending base rate case, Docket No. E-7, Sub 1214. Witness Miller also testified that EDIT resulting from the TCJA has not been incorporated in the calculation of net lost revenues for year 2021. In its pending general rate case, the Company has proposed that all excess deferred taxes be returned to customers through a separate rider. Therefore, according to witness Miller, there is no need for a placeholder in this proceeding. (Tr. 27-28.)

Witness Evans described how, in accordance with the Sub 831 Settlement, the Commission's Sub 831 Found Revenues Order, and the Sub 1032 Stipulation, DEC reduces NLR by net found revenues. (*Id.* at 71-72.) Additionally, he stated that the Company has continued the practice the Commission approved in its Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice issued on August 21, 2015 in Docket No. E-7, Sub 1073, for purposes of that proceeding, of reducing net found revenues by the monetary impact (negative found revenues) caused by reductions in consumption resulting from the Company's current initiative to replace Mercury Vapor lights with LED fixtures. (*Id.* at 72-73.)

In each of its annual rider filings, DEC performs an annual true-up process for the prior calendar year vintages. (*Id.* at 20.) The true-up reflects actual participation and verified EM&V results for the most recently completed vintage, applied in accordance with the EM&V Agreement. The Company expects that most EM&V will be available in the time frame needed to true-up each vintage in the following calendar year. (*Id.* at 21.) If any EM&V results for a vintage are not available in time for inclusion in DEC's annual rider filing, however, then the Company will make an appropriate adjustment in the next annual filing. (*Id.*)

Under the Sub 1032 Stipulation, as witness Miller explained, deferral accounting may be used for over and under recoveries of costs eligible for recovery through the annual DSM/EE rider. (*Id.* at 20.) The balance in the deferral accounts, net of deferred income taxes, may accrue a return at the net-of-tax rate of return approved in the Company's then most recent general rate case. (*Id.* at 20-21.) She testified that the methodology used for the calculation of interest shall be the same as that typically utilized for the Company's Existing DSM Program Rider proceedings. Pursuant to Commission Rule R8-69©(3), the Company will not accrue a return on NLR or the PPI. (*Id.*)

Witness Miller testified that under the Sub 1032 Stipulation and the Sub 938 First Waiver Order, qualifying nonresidential customers may opt out of the DSM and/or EE portion of Rider EE during annual election periods. (*Id.* at 28.) He stated that Rider EE will be charged to all customers who have not elected to opt out during an enrollment period and who participate in any vintage year of programs, and these customers will be subject to all true-up provisions of the approved Rider EE for any vintage in which the customers participate. Witness Miller explained that the Mechanism affords an additional opportunity for participation whereby qualifying customers may opt in to the Company's EE and/or DSM programs during the first five business days of March. (*Id.* at 28.) Customers who elect to begin participating in the Company's DSM and/or EE programs during the special "opt-in period" during March of each year will be retroactively billed the applicable Rider EE amounts back to January 1 of the vintage year, such that they will pay the appropriate Rider EE amounts for the full rate period. (*Id.* at 28-29.)

Witness Miller explained that the billing factors are computed separately for DSM and EE measures by dividing the revenue requirements for each customer class (residential and nonresidential) by the forecasted sales for the rate period for the customer class. (*Id.* at 22-23.) For nonresidential rates, the forecasted sales exclude the estimated sales to customers who have elected to opt out of paying Rider EE and the nonresidential billing factors are separately computed for each vintage. (*Id.* at 23.)

Witness Miller testified that program costs and incentives for EE programs targeted at retail residential customers across North Carolina and South Carolina are allocated to the North Carolina retail jurisdiction based on the ratio of North Carolina retail kWh sales (grossed up for line losses) to total retail kWh sales (grossed up for line losses), and then recovered only from North Carolina retail residential customers. (*Id.*) Revenue requirements related to EE programs targeted at retail non-residential customers across North Carolina and South Carolina are allocated to the North Carolina retail jurisdiction based on the ratio of North Carolina retail kWh sales (grossed up for line losses) to total retail kWh sales (grossed up for line losses), and then recovered from only North Carolina retail non-residential customers. The portion of revenue requirements related to NLR is computed based on the kW and kWh savings of North Carolina retail customers. (*Id.* at 23-24.)

For DSM programs, witness Miller noted, the aggregated revenue requirement for all retail DSM programs targeted at both residential and non-residential customers across North Carolina and South Carolina is allocated to the North Carolina retail jurisdiction based on the North Carolina retail contribution to total retail peak demand. (*Id.* at 24.) Both residential and non-residential customer classes are allocated a share of total system DSM revenue requirements based on each group's contribution to total retail peak demand. (*Id.*)

Witness Miller further testified that the allocation factors used in DSM/EE EMF true-up calculations for each vintage are based on the Company's most recently filed Cost of Service studies at the time that the Rider EE filing incorporating the true-up is made. If there are subsequent true ups for a vintage, the allocation factors used will be the same as those used in the original DSM/EE EMF true-up calculations. (*Id.* at 24.)

Witness Miller explained that DEC calculates one integrated (prospective) DSM/EE rider and one integrated DSM/EE EMF rider for the residential class, to be effective each rate period. (*Id.* at 21.) The integrated residential DSM/EE EMF rider includes all true-ups for each applicable vintage year. Given that qualifying non-residential customers can opt out of DSM and/or EE programs, DEC calculates separate DSM and EE billing factors for the non-residential class. Additionally, the non-residential DSM and EE EMF billing factors are determined separately for each applicable vintage year, so that the factors can be appropriately charged to non-residential customers based on their opt-in/out status and participation for each vintage year. (*Id.*)

Prospective Components of Rider 12

Witness Miller testified that Rider 12 consists of five prospective components: (1) a prospective Vintage 2020 component designed to collect program costs and the PPI for DEC's 2020 vintage of DSM programs; (2) a prospective Vintage 2020 component to collect program costs, the PPI, and the first year of NLR for DEC's 2020 vintage of EE programs; (3) a prospective Vintage 2019 component designed to collect the second year of estimated NLR for DEC's 2019 vintage of EE programs; (4) a prospective Vintage 2018 component designed to collect the third year of estimated NLR for DEC's 2018 vintage of EE programs; and (5) a prospective Vintage 2017 component designed to collect the fourth year of estimated lost revenues for DEC's 2017 vintage of EE programs. (Tr. 22.)

Pursuant to the Sub 938 Second Waiver Order and the Sub 1032 Order, the rate period for the prospective components of Rider 12 is January 1, 2021 through December 31, 2021. (*Id.* at 30.)

The prospective revenue requirements for Vintage 2018 are determined separately for residential and non-residential customer classes and are based on the fourth year of estimated NLR for the Company's Vintage 2018 EE programs. (*Id.* at 30-31.) The amounts are based on estimated North Carolina retail kW and kWh reductions and the Company's rates approved in DEC's most recent general rate case, Docket No. E-7, Sub 1146, which became effective August 1, 2018, adjusted as described above to recover only the fixed cost component. (*Id.* at 30.) Certain non-residential lost revenues associated with vintages through the test period January 1, 2018 through December 31, 2018, of Docket No. E-7, Sub 1214 have been removed from the prospective period as of August 1, 2020, assuming new base rates recover the new lost revenues associated with those specific kWh sales reductions. All amounts will be "trued up" pending resolution of Docket No. E-7, Sub 1214 during the next EMF period. (*Id.*)

For Vintage 2019, the Company determined the estimated revenue requirements separately for residential and non-residential customer classes and bases them on the third year of NLR for its Vintage 2019 EE programs. The amounts are based on estimated North Carolina retail kW and kWh reductions and DEC's rates approved in its most recent general rate case, adjusted to recover only the fixed cost component. Certain residential lost revenues through the updated test period February 1, 2019 through January 31, 2020 of Docket No. E-7, Sub 1214 have been removed from the prospective period as of August 1, 2020, assuming new base rates recover the net lost revenues associated with those specific kWh sales reductions. All amounts will be trued up pending resolution of Docket No. E-7, Sub 1214 during the next EMF period. (*Id.* at 30-31.)

Witness Miller also explained that the Company determines the estimated revenue requirements for Vintage 2020 separately for residential and non-residential customer classes and bases them on the second year of NLR for its Vintage 2020 EE programs. The amounts are based on estimated North Carolina retail kW and kWh reductions and DEC's rates approved in its most recent general rate case, adjusted to only recover the fixed cost component. Certain residential lost revenues through the updated test period February 1, 2019 through January 31, 2020 have been removed from the prospective period as of August 1, 2020, assuming new base rates will recover the net lost revenues associated with those specific kWh sales reductions. All amounts will be "trued-up" pending resolution of Docket No. E-7, Sub 1214 during the next EMF period. (*Id.* at 32.)

With respect to Vintage 2021, witness Miller described the basis for the rate period revenue requirements. She testified that the estimated revenue requirements for Vintage 2021 EE programs include program costs, PPI, and the first year of NLR determined separately for residential and non-residential customer classes. The estimated revenue requirements for Vintage 2021 DSM programs include program costs and PPI. The program costs and shared savings incentive are computed at the system level and allocated to North Carolina based on the allocation methodologies described by witness Miller. The net lost revenues for EE programs are based on estimated North Carolina retail kW and kWh reductions and the rates approved in DEC's most recent general rate case. (*Id.* at 30-32.)

DEC witness Miller further testified about modifications to the calculation of how much lost revenue is included in the kWh sales for the test period. She recommended using the same methodology as used to calculate how much lost revenue should be included in kWh sales for the test period in the Commission's November 29, 2018 Order Approving DSM/EE Rider and Requiring Customer Notice in Docket No. E-2, Sub 1174. Because the twelve-month test period uses actual kWh sales, and participation in EE measures occurs throughout the year, in any given twelve-month period, a full year of lost revenues is not captured in test period kWh sales as all measures were not in place at the beginning of the test period. Therefore, quantifying the actual, incremental savings by month during that twelve-month rate case test period to calculate the amount of lost revenues actually being reflected in the new base rates to be recovered from customers is appropriate. The difference between the annualized amount of energy savings and the actual amount of energy savings should be recovered through the Company's DSM/EE rider. (*Id.* at 30-31.)

EMF Components of Rider 12

Rider 12 includes the following EMF components: (1) a true up of Vintage 2016 lost revenues; (2) a true up of Vintage 2017 lost revenues; (3) a true-up of Vintage 2018 PPI, participation, and lost revenues for DSM/EE programs based on additional EM&V results received; and (4) a true-up of Vintage 2019 program costs, PPI, and lost revenues for DSM/EE programs.. (Tr. 22.)

Witness Miller testified that pursuant to the Sub 938 Second Waiver Order and the Sub 1032 Order, the "test period" for the Vintage 2019 EMF component is January 1, 2019 through December 31, 2019. As the Sub 938 Second Waiver Order allows the EMF to cover multiple test periods, the test period for the Vintage 2018 EMF component is January 1, 2018 through December 31, 2018; the test period for the Vintage 2017 EMF component is January 1, 2017 through December 31, 2017; and the test period for the Vintage 2016 EMF component is January 1, 2016, through December 31, 2016. (*Id.* at 33.)

Witness Miller explained the updates to the Vintage 2019 estimate filed in 2018 that comprise the Vintage 2019 EMF component of Rider 12. (*Id.* at 33.) Estimated participation for Vintage 2019 was updated for actual participation for the period January 2019 through December 2019. (*Id.* at 34.) Regarding NLR, estimated participation for the Year 1 Vintage 2019 estimate assumed a January 1, 2019 sign-up date and used a half-year convention, while the NLR Year 1 Vintage 2019 true up was updated for actual participation for the period January through December 2019 and actual 2019 lost revenue rates. (*Id.* at 33.) Found revenues for Year 1 of Vintage 2019 were trued up according to Commission approved guidelines. (*Id.* at 35.) To reflect the results of EM&V, Vintage 2019 estimated avoided cost savings were updated pursuant to the EM&V Agreement. (*Id.* at 33.) Finally, while the Vintage 2019 estimate included only the programs approved prior to the filing of the estimated Vintage 2019 revenue requirement, the Vintage 2019 true up was updated for new programs and pilots approved and implemented during Vintage 2019. (*Id.* at 33.) For DSM programs, the Vintage 2019 true up reflects the actual quantity of demand reduction capability for the Vintage 2019 period. (*Id.* at 34.)

Actual Year 1 (2019) NLR for Vintage 2019 were calculated using actual kW and kWh savings by North Carolina retail participants by customer class in 2019, based on actual participation and load impacts applied according to the EM&V Agreement. (*Id.* at 35.) The rates applied to the kW and kWh savings are those in effect for 2019, reduced by fuel and variable operation costs. (*Id.*) NLR were then offset by actual found revenues for Year 1 NLR of Vintage 2019. (*Id.* at 35.) NLR were calculated by rate schedule within the residential and non-residential customer classes. (*Id.*)

Witness Miller also described the basis for the Vintage 2018 EMF component of Rider 12. (*Id.* at 35.) She explained that avoided costs and NLR for Vintage 2018 EE programs were trued up based on updated EM&V participation results and the impacts of DEC's recent rate case, Docket No. E-7, Sub 1146. (*Id.* at 35.) Avoided costs for Vintage 2018 DSM programs were trued up to update participation results. (*Id.*) She explained that the actual kW and kWh savings were as experienced during the period January 1, 2018 through December 31, 2018. (*Id.*) The rates applied to the kW and kWh savings are the retail rates that were in effect during each period the lost revenues were earned, reduced by fuel and other variable costs. (*Id.* at 35.)

Witness Miller explained the basis for the Vintage 2017 EMF component of Rider 12. (*Id.*) She explained that all years were trued-up based on updated EM&V results. (*Id.* at 35.) She explained that the actual kW and kWh savings were as experienced during the period January 1, 2017 through December 31, 2017. (*Id.*) The rates applied to the kW and kWh savings are the retail rates that were in effect during each period the lost revenues were earned, reduced by fuel and other variable costs. (*Id.* at 36.) Witness Miller's supplemental testimony and exhibits reflected

EMF billing factors for Rider 12 of 0.1011 cents per kWh for all North Carolina retail residential customers, (0.0001) cents per kWh for Vintage 2016 DSM participants, 0.0193 cents per kWh for Vintage 2016 EE participants, 0.0000 per kWh for Vintage 2017 DSM participants, 0.0342 cents per kWh for Vintage 2017 EE participants, (0.0014) cents per kWh for Vintage 2018 DSM participants, (0.0049) cents per kWh for Vintage 2018 EE participants, 0.0019 cents per kWh for Vintage 2019 DSM participants and (0.0225) cents per kWh for Vintage 2019 EE participants.

Public Staff Review of Company Rider 12 Calculations

As discussed above, Public Staff witness Williamson filed testimony in this proceeding discussing EM&V and cost effectiveness issues related to future DSM/EE proceedings for the Company. None of these topics and issues necessitates an adjustment to the Company's billing factor calculations. Public Staff witness Maness testified that his investigation of DEC's filing in this proceeding focused on whether the Company's proposed DSM/EE billing factors were calculated in accordance with the Sub 1032 Stipulation, the Sub 1130 Order, and the Mechanism and whether they otherwise adhered to sound ratemaking concepts and principles. (Tr., 323.) Except for the items discussed below, witness Maness testified that he believes that the Company has calculated the Rider 12 billing factors in a manner consistent with N.C.G.S. § 62-133.9, Commission Rule R8-69, the Sub 1032 Stipulation, the Sub 1130 Order, the Mechanism, and other relevant Commission orders. (*Id.* at 324.)

Witness Maness testified that as part of its investigation in this proceeding the Public Staff performed a review of the DSM/EE program costs incurred by DEC during the 12-month period ended December 31, 2019. To accomplish this, the Public Staff selected and reviewed a sample of source documentation for test year costs included by the Company for recovery through the DSM/EE riders. Review of this sample is intended to test whether the costs included by the Company in the DSM/EE riders are valid costs of approved DSM and EE programs. As of the date of the filing of the Public Staff's testimony, this program cost audit was still underway. (*Id.* at 323.) Witness Maness noted in his testimony that if any issues or necessary adjustments are found during the completion of this process, the Public Staff would file supplemental information in this proceeding. (*Id.* at 324.)

Witness Maness further noted the following with respect to the Public Staff's investigation:

- Review of Vintage year 2019 Program Costs – The Public Staff's review of the selected sample items from the 2019 DSM/EE program costs resulted in one exception related to certain adjustments that the Company made to its DSM/EE program costs in last year's DSM/EE rider proceeding, Docket No. E-7, Sub 1192. In that proceeding, the Company and the Public Staff made adjustments to the program costs included in the calculation or Rider 11 to incorporate certain credits to Vintage Year 2018 North Carolina retail program costs that were not actually recorded in the Company's general ledger until 2019. Thus, to calculate Vintage Year 2019, North Carolina retail program costs for purposes of Rider 12 to be set in this proceeding, the Company rightly undertook to reverse the credits recorded in the general ledger in 2019 that were already reflected in the Rider 11 calculation. Witness Maness reported, however, that during its investigation in this case, the Public Staff determined that the Company had inadvertently calculated a greater reversal than it should have, thus overstating North Carolina retail Vintage Year 2019 program costs by approximately $725,000. The Company agreed with the adjustment, and subsequently incorporated it into witness Miller's Supplemental Testimony and Exhibits, which also incorporated three supplemental Evan's exhibits. (*Id.* at 324-26.)

- Return on Deferred Program Costs and Interest on Over Recoveries – As stated in past proceedings, the Public Staff reserves the right to raise the issue of the appropriate interest rate on over recoveries of utility incentives in the future proceedings. (*Id.* at 326.)

Witness Maness also included two adjustments in his testimony. He concluded the adjustments he recommended should be incorporated into the DSM/EE billing factors, and that these factors should be approved subject to any true-ups in future cost recovery proceedings consistent with the Sub 1032 Settlement, the Sub 1130 Order, and the Revised Mechanism, as well as other relevant orders, including the Commission's final order in this proceeding. (*Id.* at 328-29.)

Application of Reserve Margin to Avoided Capacity Costs

Public Staff witness Hinton testified that, for the first time, the Company is proposing in this proceeding to increase the value of the demand reduction benefits from EE programs by 17% by including a 17% reserve margin adder in the calculation of avoided capacity costs. Witness Hinton explained that in DEC's Integrated Resource Plan (IRP), DEC reduces its peak load by the amount of the demand reduction from EE programs, which DEC considers to be a demand-side resource, as shown in the Load, Capacity, and Reserve (LCR) Tables included in DEC's IRP. He acknowledged the Company's argument that since it increases the amount of supply-side resources required to meet the projected peak load by a 17% reserve margin, a similar reserve margin adjustment would be appropriate for demand-side resources, but ultimately, witness Hinton was not persuaded that a 17% reserve margin adder to the avoided capacity cost is appropriate. He used a table to illustrate his opposition to this addition showing that DEC projects generating reserves of 3,591 MW, for a reserve margin of 19.3%. Witness Hinton then stated that if DEC had 100 MW more EE during this year, the load forecast would be reduced by 100 MW, which increases the reserve margin to 3,691 MW, or 20.0%.

Further, witness Hinton pointed out that under DEC's premise, a 100 MW load reduction from EE should reduce DEC's existing generating capacity by 119 MW to maintain its reserve margin, thereby equating the value to customers of 100 MW of demand-side EE programs to 119 MW of supply-side resources, which is logical from an IRP planning perspective. (Tr. at 206-08.) However, he questioned whether this is the appropriate value of a MW of load reduction to customers for ratemaking purposes and argued that it would be unfair to customers to force them to pay 17% more for the same amount of demand reduction from a demand-side resource. (*Id.* at 208.) In other words, witness Hinton pointed out that the weakness in DEC's argument is the inequity of asking customers to pay 17% more for the same MW reduction from an EE program versus from a DSM program. Again, witness Hinton acknowledged that DEC has a theoretical basis from a planning standpoint, but he described it as deficient from a ratemaking standpoint. (*Id.* at 209.)

Witness Hinton further disagreed with including the 17% reserve margin adder for EE programs because it is inconsistent with the methodology for calculating avoided costs that was approved by the Commission in the most recent biennial avoided cost proceeding, Docket No. E-100, Sub 158 (Sub 158). He cited previous testimony where he endorsed using PURPA-based avoided costs to link the savings and financial incentives afforded the Company for its DSM/EE programs with the rates it pays to QFs for avoided energy and avoided capacity. (*Id.* at 211-12.) However, he believes that the proposed reserve margin adjustment diverges too far from what the Commission approved in the Sub 158 proceeding. He expressed concern that this is not the appropriate proceeding to evaluate such a significant change, rather, in his opinion, such a change should be addressed in the next mechanism review. He further stated in response to questions from the Commission that if the Commission were persuaded to add a reserve margin adder, he agreed with witness Duff's "back-up plan" of netting out the reserve margin adjustment (Tr. at 292.)

The revenue impact of Witness Hinton's removal of the reserve margin adder on the calculation of the PPI would be a reduction of $618,791. (*Id.* at 213.)

Company witness Duff testified that applying a reserve margin factor to determine the avoided cost value associated with the Company's EE programs for vintage 2021 is appropriate. Because EE is treated as a load reduction in the IRP, rather than as a load serving resource, it should have a 17% reserve margin factor applied to it just as it would be appropriate to apply a 17% planning reserve margin factor to an increase in system load. Witness Duff testified that because of every kW of load reduction that comes from EE, the Company does not need to plan for the 1.17kW of capacity required to serve that load. (*Id.* at 119.)

Company witness Duff also clarified several assertions in witness Hinton's testimony. First, he clarified that witness Hinton's statement that the reserve margin was applied by the Company to all the MW reductions (demand reduction benefits) associated with the Company's EE programs beginning with vintage year 2021 by explaining that the Company had applied the adjustment to avoided capacity benefits but not to avoided transmission and distribution benefits. Next, witness Duff explained that witness Hinton's testimony and table did not accurately reflect DEC's proposal and position. The Company proposes to use the 17% reserve margin, in which case the 100 MW load reduction example from witness Hinton's testimony would yield a 117 MW reduction in generating capacity needs, not the 119 MW shown in witness Hinton's table. (*Id.* at 120-21.)

Witness Duff further testified that DEC's customers will benefit from DEC's proposal. He disputed that witness Hinton's assertion that customers will not realize the claimed value of the reserve margin adjustment. He explained that although the 2019 IRP shows DEC's actual reserve margin is greater than 17% in the near term, there is no reason to assume that there is no capacity value to building EE resources several years before the in-service date of a new generating unit. The majority of EE measures in DEC's vintage 2021 portfolio have a life more than six years, which is about the time that the DEC's 2019 IRP demonstrates the need for new combustion turbine generation. Therefore, those EE measures with longer lives directly contribute peak load and reserve margin savings during and after the in-service date of the next planned generating unit. Witness Duff noted that even witness Hinton acknowledged that customers will ultimately benefit from the 100 MW of load reduction due to an EE program and recognized it was likely that in the future supply-side resources will be below the 17% margin and customers would see the value of the 100 MW of added demand reduction from EE programs. Because EE programs are built one customer or measure at a time, it typically takes several years to build a significant amount of peak load savings from EE customers. Therefore, witness Duff concluded, EE implementation needs to begin well in advance of the date it is needed. (*Id.* at 121.)

Witness Duff also disputed witness Hinton's contention that the PAF used in calculating the Company's avoided cost rates appropriately reflects a reserve margin and not simply an effective forced outage rate. Even if it reflected a reserve margin, witness Duff testified, an appropriate adjustment would not be to remove the adjustment, but instead to apply a 11.429% adder to the Avoided Capacity value for EE programs in order to factor in a 5% PAF to reflect a total 17% reserve margin. (*Id.* at 123.) Upon questions from the Commission, witness Duff further explained that although the PAF had initially been thought of as a reserve margin adjustment, it is now a reflection of the effective forced outage rate associated with capacity. (*Id.* at 168-69.) Additionally, witness Duff testified that, contrary to witness Hinton's assertion that the Company had not previously applied a reserve margin factor in its analysis of EE programs, prior to merger of Duke Energy Corporation and Progress Energy, Inc., Duke Energy Progress, LLC (DEP) used the Strategist model cost-effectiveness tool, and that tool modeled a reserve margin factor associated with capacity savings from energy efficiency. (*Id.* at 177.)

Seasonal Allocation

Public Staff witness Hinton expressed concern about the Company's use of seasonal allocation factors for "legacy" DSM programs. He stated that DEC distinguished between "legacy" and "incremental" DSM programs in the evaluation of its DSM portfolio and cost-effectiveness, and that DEC maintains that its legacy DSM programs should continue to be valued using a 100% summer seasonal allocation weighting. (*Id.* at 213-14.)

Witness Hinton agreed that the Company is winter planning, and he agreed with the Company's treatment of its incremental DSM programs with respect to the seasonal allocation weightings, but he did not agree with the Company's treatment of legacy DSM programs. Because the Company is now winter planning, he concluded that the value of summer DSM is diminished for resource planning purposes in terms of a capacity resource at the expected time of peak and the dollar per kW associated with the demand reductions. (*Id.* at 216.) Therefore, he recommended that the Commission direct the Company to treat its legacy DSM programs as it had treated its incremental DSM programs. (*Id.* at 216.)

Witness Hinton testified his recommendation would provide "added motivation" to the Company to find ways to reduce winter peak. Although aware that the Company had already begun such an investigation, he believed that his proposed method applying 10% seasonal capacity value to legacy DSM programs would appropriately direct the Company to emphasize programs that focus on reducing load for the winter season, as it would increase the incentives for reducing growth of winter peak demands. (*Id.* at 217.)

Witness Hinton said his recommendation would not result in the DSM programs causing legacy DSM programs to fail cost-effectiveness tests. These programs remain cost-effective in part due to the significant role of avoided transmission and distribution (T&D) cost, which provide almost the same beneficial value as 100% of the avoided capacity cost. (*Id.* at 222.)

Company witness Duff opposed witness Hinton's recommendations in his rebuttal testimony. First, witness Duff testified that consistent with the agreement with the Public Staff in E-7, Sub 1130, DEC used the peaker method. He disagreed with witness Hinton's assertion that the Company had acted inconsistently with the Commission's order in Sub 1130 by not applying the 10% seasonal allocation factor to the avoided cost associated with DEC's legacy DSM programs. (*Id.* at 106-07.) DEC was surprised by the Public Staff's position on Docket No. E-7, Sub 1130, because DEC did not believe that the revisions to the Sub 1130 Agreement amended how the Company calculated the avoided capacity costs used to evaluate existing programs approved by the Commission that were part of the Company's existing portfolio of programs. (*Id.* at 107.) Witness Duff explained that to recognize the growing need for winter capacity and encourage EE and DSM programs that will provide winter capacity savings, the Company voluntarily applied the 90% winter 10% summer seasonal allocation approved in the most recent Avoided Cost Proceeding to Vintage 2021. In addition to encouraging winter DSM, witness Duff believed that this approach aligned better with the way new QFs receive capacity value from the last avoided cost proceeding. (*Id.* at 109.) Witness Duff pointed out that this approach is consistent with how new QF capacity is treated in the Commission's Notice of Decision and April 15, 2020 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 158 (Sub 158 Order). He stated the Commission acknowledged that the currently high solar penetrations in Duke's service territory will have different impacts of summer versus winter loads net of solar contribution in the past. (*Id.* at 108-09.)

Witness Duff acknowledged that neither the Company nor the Public Staff had previously raised an argument about the seasonal allocation that the Commission approved in Docket No. E-100, Sub 148, but the Company raised it in this proceeding for the reasons he discussed. Witness Duff highlighted that just as the Commission did not retroactively apply its Sub 158 seasonal allocation factors to QFs that had previously established power purchase agreements (PPAs) at avoided cost rates that were approved based on past prevailing circumstances, the Company did not retroactively apply the seasonal allocations approved in Sub 158 to legacy DSM programs. (*Id.* at 110-111.)

Witness Duff also testified that the Company's treatment of legacy DSM programs was consistent with the Commission's order in the 2018 DSM/EE proceeding in Docket No. E-7, Sub 1164. In that proceeding, the Public Staff recommended that the Commission assign zeros to capacity for legacy DSM programs until the first year of need as shown in the Company's IRP, based on the Commission's order in the then preceding avoided cost case, Docket No. E-100, Sub 148, and House Bill 589's recent amendments to N.C.G.S. § 62-156(b)(3). The Company opposed this recommendation, arguing that its DSM programs had been established over a number of years and were a useful resource. Additionally, the Company had argued that legacy DSM programs should be treated as QFs that established legally enforceable obligations prior to November 15, 2016, in accord with the conclusions of the Commission and House Bill 589, which did not retroactively apply to those QFs. (*Id.* at 112.)

Witness Duff also explained that from an integrated resource planning (IRP) standpoint DEC's legacy DSM programs were viewed as a "dispatchable resource that is available for the entire fifteen-year planning period." (*Id.* at 113.) He noted this DSM resource has the flexibility to dispatch any time throughout the day depending on the net load on the system after accounting for the must-take solar output on the grid. Power Manager is available to dispatch into the evening hours when net load is high and solar output is diminished, a circumstance known as the "duck curve." Conversely, he indicated that, if solar is lost due to midafternoon cloud cover, demand response can be used to make up for diminished irradiance. As an IRP resource, both existing AC demand response and existing solar resources are oriented toward summer peak demand reduction, helping to meet customer peak demand in the summer. The capacity value from these resources is at least in part the reason incremental resource decisions are now geared toward winter peak demand needs. (*Id.*)

Witness Duff countered witness Hinton's contentions about applying the 10% summer allocation to DEC's legacy DSM. First, he explained that witness Hinton's argument that DEC's DSM programs were short lived was erroneous. He agreed that the Company recognizes a one-year measure life, but he noted that that was a function of the cost-recovery method DEC uses to recover its DSM/EE costs. Although DEC recognizes a one-year measure life, a legacy DSM resource has been built over time and has a term of implicit contract with customers. According to witness Duff, this more closely resembles the life of a load control switch than it does a one-year measure life. (*Id.* at 114.) He further explained that DEC's legacy DSM programs have a 1% annual net attrition rate after factoring in that most new customers moving into a home where the prior resident was a DSM participating customer choose to continue participation in the DSM program. He cited the Public Staff's previous acknowledgment that the DSM programs in the DEC IRP were "stable and expected to continue for the foreseeable future." (*Id.* at 114.)

Witness Duff next disputed witness Hinton's contention that the capacity value of the legacy summer DSM resources has changed because of changes in the Company's system lambda. He explained that changes in the Company's system lambdas could just as easily be explained by the milder 2017-19 summers when compared to the summer of 2016, where summer DSM programs were activated a significant number of times. (*Id.* at 115.) He stated that his cursory examination of historical temperatures indicated that the summer of 2016 was much hotter than normal. Moreover, the full value of a summer DSM resource is realized during extreme weather days when the ability to dispatch a summer DSM program provides peak load reduction that is less expensive to customers than starting and running more expensive peaking generation. (*Id.* at 116.) The value to customers is having the capacity available when it is needed. (*Id.* at 148.)

Witness Duff said that the Public Staff's recommended approach was not necessary to better encourage the Company to promote winter-focused DSM and EE programs. The Company is already investigating winter DSM programs with the Collaborative and has adjusted its seasonal allocations for new and incremental programs to encourage winter-focused DSM. (*Id.* at 149.) Witness Duff testified, however, that if the Commission changes seasonal allocations in the next avoided cost proceeding and then applies those changes retroactively, it can make planning those winter DSM programs "exceedingly hard" because it would be changing the resource that the Company had planned with a certain value. This could adversely impact cost-effectiveness as well. (*Id.* at 163, 117.) Witness Duff cautioned that, although he agreed that witness Hinton's assertion that his recommendation would not result in the legacy DSM programs becoming non-cost effective for Vintage Year 2021, recognizing only 10% of the avoided capacity value on legacy DSM results in the majority of the avoided costs associated with the legacy resource coming from avoided T&D. Because the Commission has required avoided T&D rates to be studied and updated prior to 2022, the continued cost-effectiveness of these programs is uncertain, particularly if there is a drop in these T&D values. Witness Duff cited the Commission's order in Docket No. E-7, Sub 1164, where the Commission stated that assigning a zero-capacity value to DSM programs would under-value the contributions of those programs and send the wrong pricing signal. Based on that order, he concluded that it logically follows that assigning a 10% value for avoided capacity to an existing summer DSM resource would undervalue the value of this capacity resource. (*Id.* at 118.)

Finally, witness Duff noted that witness Maness' testimony that the Public Staff's proposed reduction to the PPI of $5,093,947 was based on an erroneous data request response from the Company. The Company had notified the Public Staff of the error, but the correction had not been incorporated into witness Maness's testimony. The corrected amount of the Public Staff's proposed reduction is $3,624,753. (*Id.* at 119.)

Supplemental Adjustments

In her supplemental testimony and exhibits, Company witness Miller updated the lost revenue of Vintages 2018, 2019, and 2021 because the Company's internal review process determined an EM&V update was necessary. The update resulted in a decrease of ($34,729) to lost revenue. Witness Miller's supplemental testimony and exhibits also reflected adjustments to Vintage 2019 program costs resulting from the Public Staff's program cost audit and the inclusion of Vintage 2016 lost revenues due to an inadvertent omission of exhibits from the original filing. Company witness Miller explained that correcting the error discovered during the Public Staff's audit resulted in a reduction of system level program cost expenses in the amount of $992,045.69 and an increase in the PPI of $83,560. Witness Miller also testified that the Company had determined that Vintage 2016 had been inadvertently excluded from the original Rider 12 filing. According to witness Miller, non-residential lost revenues associated with the test period (twelve months ending December 31, 2016) of the Company's general rate case proceeding in Docket No. E-7, Sub 1146 were adjusted based on specific enrollment dates, and a portion of these lost revenues were removed from the prospective period as of August 1, 2018 and included in base rates. The remaining portion of the lost revenues should have been included in calendar year 2019 for Vintage 2016. Witness Miller testified no changes were made to residential lost revenue or the non-residential Vintage 2016 DSM calculations. She further testified that the 2016 revenues collected have been incorporated in the exhibits, and that any applicable interest has been calculated. (Tr., 41-43)

The changes described by witness Miller in her supplemental testimony impacted the following proposed rates: the residential EMF rate, non-residential Vintage Year EE 2016 EMF rate, non-residential Vintage Year DSM 2016 EMF rate, and the non-residential Vintage Year DSM 2019 EMF rate. These updates were reflected on Supplemental Miller Exhibits 1-4; Supplemental Miller Exhibits 6-7; and Supplemental Evans Exhibits 1-3. (*Id.* at 42-44.)

Additionally, in her Supplemental Testimony, witness Miller requested approval of the following annual billing adjustments, on a cents per kWh basis, with regulatory fee included:

Residential Billing Factors	**¢/kWh**
Residential Billing Factor for Rider 12 Prospective Components	0.4184
Residential Billing Factor for Rider 12 EMF Components	0.1011

Non-Residential Billing Factors for Rider 12 Prospective Components	**¢/kWh**
Vintage 2018 EE Participant	0.0137
Vintage 2019 EE Participant	0.0687
Vintage 2020 EE Participant	0.0612
Vintage 2021 EE Participant	0.3522
Vintage 2021 DSM Participant	0.1200

Non-Residential Billing Factors EMF Component	**¢/kWh**
Vintage 2019 EE Participant	(0.0225)
Vintage 2019 DSM Participant	0.0019
Vintage 2018 EE Participant	(0.0049)
Vintage 2018 DSM Participant	(0.0014)
Vintage 2017 EE Participant	0.0342
Vintage 2017 DSM Participant	0.0000
Vintage 2016 Participant	0.0193
Vintage 2016 Participant	(0.0001)

(*Id.* at 44-45.)

Public Staff witness Maness filed supplemental testimony on June 8, 2020, in which he stated that the Public Staff had completed its two-year review of test year program costs and other than the items mentioned in his direct testimony and adjusted by the Company in its supplemental testimony, had found no material difference between the program costs as filed by the Company and reflected in the supporting documentation examined. (*Id.* at 340.)

Conclusions on Calculations of Rider EE

Based on the foregoing, the Commission finds and concludes that the components of Rider 12 are consistent with the Commission's findings and conclusions herein, as well as the Commission's findings and conclusions as set forth in the Sub 1032 Stipulation and the Mechanism approved in the Sub 1032 Order, as revised by the Sub 1130 Order. The Commission approves the Company's calculation of the DSM/EE rates for Vintage 2021 as reflected in the supplemental testimony and exhibits of DEC witness Miller, with the exception of the impact of the 17% reserve margin adder on EE programs.

Reserve Margin Conclusions

With respcet to the Company's application of the reserve margin adder to the calculation of avoided capacity costs associated with EE programs, the Commission concludes that there is indeed a theoretical basis for such an adjustment, as noted by witness Hinton. (Tr. 209.). The Commission notes that EE is treated as a load resource in the Company's IRP and agrees that with every kW of load reduction that comes from EE, the amount of load serving capacity for which the Company must plan is reduced by more than one kW. However, exactly how much the reserve margin adjustment should be is not supported by substantial evidence in this docket. The Commission concludes that, for purposes of calculating the avoided capacity cost benefits for DSM/EE programs, deviation from the approved methodology for calculating the avoided capacity costs that form the basis for rates paid to QFs is appropriate and that this matter should be studied by the Collaborative. Therefore, the Commission directs the parties to endeavor to identify an appropriate reserve margin adjustment to be used for EE programs in future proceedings.

Seasonal Allocation Conclusions

The Commission approves the Company's proposed use of the seasonal allocation weightings to new, incremental DSM programs, and does not approve the Public Staff's recommendation to extend those seasonal allocation weightings to DEC's legacy DSM programs. The Commission agrees that the Company's distinction between legacy DSM (the capacity resource that has been built from historic and planned DSM programs or the amount of DSM capacity in the Company's 2018 IRP forecast as a load serving resource) and incremental or new DSM capacity (the capacity resources that are built from new participation in DSM programs that were not factored into the Company's IRP as a load serving resource) is appropriate for purposes of this proceeding. The Commission further concludes that the Company's applying the 10% summer and 90% winter seasonal allocation factor to the avoided capacity cost associated with its new, incremental DSM program for estimating program cost effectiveness and the Company's projected PPI are consistent with the method approved in Docket No. E-7, Sub 1130. Although the Commission recognizes that the Sub 1130 Agreement does not expressly compel the

Company to apply the seasonal allocation weightings and that neither the Company nor the Public Staff has previously included them in their calculations, the Company's application of the seasonal allocation weighting is wholly consistent with the intent of the Sub 1130 Agreement, which directs that the PPI and any PPI true-up will be derived from the underlying resource plan, production cost model, cost inputs that generated the avoided capacity, and avoided energy credits reflected in the most recent Avoided Cost Proceeding. The issue of seasonal allocation was litigated and decided in the Commission's conclusions in the Sub 158 Order. *See e.g.* Notice of Decision, Docket No. E-100, Sub 158 at 8; and Sub 158 Order at Finding of Fact Nos. 6 and 7 and at 17-29. Therefore, the Company's adoption of the seasonal allocation weightings in the present DSM/EE proceeding is consistent with the Sub 1130 Agreement, as it reflects the most recent biennial determination of avoided cost rates for electric utility purchases.

The Commission additionally finds that the Company's adoption of the recently approved seasonal allocation of avoided capacity values for new incremental programs is also consistent with the Sub 158 Order directive to the Company to "place additional emphasis on defining and implementing cost-effective DSM programs that will be available to respond to winter demands." Sub 158 Order at 28-29. Before this proceeding, winter DSM programs had zero capacity value assigned to them for cost effectiveness and PPI calculations. (Tr., 155.) Accordingly, and as DEC witness Duff responded to Presiding Commissioner Brown-Bland's inquiry, in order to recognize the growing need for winter capacity and to encourage EE and DSM programs that will provide winter capacity savings, the Company applied the seasonal weighting for future capacity needs of 90% in the winter and 10% in the summer to encourage the development and specific promotion of new EE and DSM programs that provide winter capacity savings. The Commission does not conclude that applying the 10% seasonal weighting to existing DSM programs is necessary or appropriate for the Company to turn its focus at this time to winter-oriented DSM programs.

Although the PURPA method contemplates treating legacy DSM/EE programs as legacy QFs are treated for purposes of applying Avoided Cost Proceeding conclusions prospectively, it does not mandate that the Commission view the value of demand response capacity the same as the value of capacity from a QF. The Commission has previously rejected equating QF capacity and DSM capacity in its Order Approving DSM/EE Rider and Requiring Filing of Customer Notice, Docket No. E-7, Sub 1164, issued Sept. 11, 2018 (Sub 1164 Order). In that docket, the Public Staff contended that because the Commission had approved the use of zero for capacity costs in years where the Company did not show a need for capacity to calculate avoided cost rates for new and incremental QFs in Docket No. E-100, Sub 148, the Mechanism compelled DEC to likewise apply zeros to its calculation of avoided capacity costs for purposes of calculating the PPI and cost-effectiveness in DSM/EE proceedings. The Commission, however, recognized that DSM provides a capacity value to customers that is different from that provided by QFs. The Commission concluded in the Sub 1164 Order that "evaluating the contributions that DSM/EE measures make to a utility avoiding future capacity needs to determine cost-effectiveness is inherently different than the evaluation taken to determine the capacity costs avoided through the purchase of electric output from a QF." Sub 1164 Order at 44. It logically follows that assigning a 10% value for avoided capacity to an existing DSM resource, as the Public Staff urges in this case, would also undervalue this capacity resource.

The Commission further concludes that DEC's legacy DSM programs, should not be treated as new or incremental. The evidence at the hearing showed that DEC's DSM programs included in the IRP block are stable and expected to continue for the foreseeable future. (Tr., 114.) From a system planning perspective, the peak MW capability of the DSM programs is included in all 15 years of the IRP. (*Id.* at 113, 172-73.) In other words, the legacy DSM programs are viewed as a dispatchable resource that is available for the entire 15-year IRP planning horizon. (*Id.* at 114.) As an IRP resource, both existing demand response and existing solar QF resources are oriented toward summer peak demand reduction, helping to meet customer peak demand in the summer. The capacity value from these resources is at least in part why incremental resource decisions are now geared toward winter peak demand needs. (*Id.* at 113.) This does not mean that the existing summer-oriented resources have less value, but recognizes that *incremental* additions to those resources, whether they are solar or DSM, would have diminished incremental value.

The Commission also agrees that although DEC adopted a one-year measure life for DSM programs for cost-recovery purposes (DEC does not amortize for cost recovery purposes under N.C.G.S. § 62-133.9), this does not mean that legacy DSM programs should be treated as incremental. The Commission notes that DEP, which recovers its DSM/EE costs differently, recognizes 25 years of peak reduction impacts at the point a new customer signs up for DSM. (Tr., 114.) The recognized measure life ties to the switch life, which is 25 years. (*Id.* at 142.) As with DEC, the Commission approved new seasonal allocation weightings for DEP in Sub 158 as well – 100% winter. If the Commission applied the Public Staff's argument to DEP, it would lead to the illogical conclusion of retroactive application of zero value seasonal allocation weightings for a DSM resource that has already been deemed used and useful for a 25-year life.

The Commission is also not persuaded that DEC's legacy summer DSM programs should have the 10% seasonal allocation weighting because DEC has had fewer activations of them in the past four years. As witness Duff testified, that decrease in activations could just as easily be explained by the milder 2017-19 summers when compared to the summer of 2016, when summer DSM programs were activated a significant number of times. Witness Duff stated that his cursory examination of historical temperatures indicated that the summer of 2016 was much hotter than normal. No party contested witness Duff's testimony in this regard. Moreover, the full value of a summer DSM resource occurs during extreme weather days where the ability to dispatch a summer DSM program provides peak load reduction that is less expensive to customers than starting and running a more expensive peaking generation. (*Id.* at 115-116.) In this respect, existing summer DSM capacity provides a reliable value to customers. Thus, legacy DSM capacity should not be valued the same as incremental, new QF capacity.

The Commission also concludes that the Public Staff's approach to legacy DSM programs makes them less cost effective and changes preexisting methods of valuing legacy DSM programs. Although the Public Staff's approach does not result in the Company's legacy DSM programs being not cost effective for Vintage 2021, the approach does have potential adverse long-term impacts on this important legacy summer resource. With only 10% of the avoided capacity value being recognized under the Public Staff's approach, most of the avoided costs associated with this legacy resource come from avoided T&D value. The Commission has required the avoided T&D rates to be studied and updated prior to 2022. If T&D costs decrease, it would further imperil the cost-effectiveness of these programs. Given that uncertainty, the Public Staff's approach jeopardizes the cost-effectiveness of these programs, and thereby potentially jeopardizes their continuation. Building back a DSM resource after it has become non-cost-effective takes time. (*Id.* at 164, 191.) Although avoided T&D costs may increase rather than decrease, this does not mitigate the Commission's concern about the continued cost effectiveness of these programs. As witness Duff pointed out, the general trends of avoided costs have been downward. (*Id.* at 190.)

The Commission is also concerned that the Public Staff's position would impede the Company's ability to effectively plan DSM programs, especially winter DSM programs. By applying the 90% seasonal allocation weighting to new, incremental EE and DSM winter programs and participation, the Company has complied with the Commission's direction in Sub 158 to develop winter oriented DSM and EE programs. (*Id.* at 116, 155.) The Company has already started to discuss these types of programs within the Collaborative. However, if seasonal allocation weightings applications change every two years and are applied retroactively to legacy DSM and EE, planning for those resources would be complicated and difficult. (*Id.* at 163.) The Commission has indicated that it will revisit seasonal allocations in future avoided cost proceedings. (*Id.*) Therefore, under the Public Staff's proposed method, as the Company builds its winter DSM resources, it has no certainty, based on the variables listed above, that seasonal allocations will not shift in the future or that T&D avoided costs may will not decrease. Adopting the Public Staff's approach, therefore, potentially undermines the long-term viability of winter DSM programs.

Finally, the Commission agrees that legacy DSM programs are a desirable resource mandated by the State. Senate Bill 3 was enacted in 2007 "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS)." N.C.G.S. § 62-2(10). The enactment of REPS required each electric public utility in the State to meet increasing percentages of its energy needs each year through EE measures. N.C.G.S. § 62-133.8. Finally, Senate Bill 3 provided that the utilities shall be compensated for their DSM/EE efforts and allowed awarding of incentives, including rewards based upon shared savings and avoided costs achieved by DSM/EE measures. N.C.G.S. § 62-133.9. Therefore, inasmuch as the Public Staff's seasonal allocation method would reduce the Company's incentive, the Commission finds the method inconsistent with North Carolina policy. Accordingly, the Commission approves the Company's seasonal allocation methodology.

The Commission understands the Public Staff's concerns about the significance of the Mechanism in setting expectations on how the Company recovers its program costs, NLR, and PPI. The Mechanism refers to the most recent avoided cost case as a guide to how the Company calculates its cost effectiveness for programs. However, because the Commission biennially establishes avoided cost rates based on the regulatory and economic circumstances present every two years, avoided cost methodologies may change from time to time. Therefore, to account for interim changes in the economic and regulatory circumstances reflected in the biennial avoided cost proceedings, the Commission directs the Company in future DSM/EE proceedings to specifically address in its direct testimony whether it has altered its methodology for calculating avoided energy and capacity costs from the previous proceeding, and, if it has, to identify how the most recent avoided cost case justifies that change.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30-31

The evidence in support of these findings and conclusions can be found in the testimony of DEC witness Evans and NC Justice Center, *et al.*, witness Bradley-Wright.

Company witness Evans described the Collaborative's activities since the June 11, 2019 hearing in the previous EE/DSM rider docket. He stated that the Collaborative continued to meet bimonthly for formal meetings in July, September, and November of last year and in January of 2020. Between the meetings, interested stakeholders joined conference calls in June, September, October and February, and informal meetings were held in July and November to focus on certain agenda items or priorities that could not be explored fully in the formal meetings. Witness Evans stated that such meetings and calls would continue similarly through 2020 as well. (Tr., 76-77.)

Witness Evans also described how members of the Collaborative participated and provided input to the Company. He noted that the Company had begun to bring program ideas to the Collaborative during the research phase before all assumptions are decided so that members can meaningfully contribute to proposals for new programs or modifications to existing ones. (*Id.* at 77.) Although the Collaborative sometimes explores ideas that do not result in new or modified programs, witness Evans asserted that the lively and diverse collaborative discussions could lead to discovering new ideas. (*Id.*) Additionally, witness Evans testified that a Collaborative member had pointed the Company to tax credits that had benefitted low-income customers. The Collaborative had also identified other programs for low-and middle-income customers, manufactured homes, and renters. Witness Evans indicated that the Company looked forward to working with the Collaborative on these opportunities. Finally, witness Evans testified that in response to some who had expressed a desire for a standard reporting protocol, the Company is developing a new structure for reporting DEC's and DEP's program performance metric to the Collaborative. (*Id.* at 78-79.)

Company witness Evans also testified that opt outs by qualifying industrial and commercial customers have had a negative effect on the Company's overall non-residential impacts. (*Id.* at 73.) For Vintage 2019, 4,962 eligible customer accounts opted out of participating in DEC's non-residential portfolio of EE programs, and 5,537 eligible customer accounts opted out of participating in the Company's non-residential DSM programs. (*Id.* at 72.) During 2019, however, 11 opt-out eligible customers opted into the EE portion of the Rider, and 28 opt-out eligible customers opted into the DSM portion of the Rider. Witness Evans explained that because the Company does not participate in its customers' economic benefit analyses or decision-making processes, providing a reason for the increase in opt-outs is difficult. The Company believes, however, that its non-residential customers are economically savvy and may be best equipped at determining the economic benefit of participating in the Company's DSM/EE programs. According to witness Evans, this knowledge, coupled with the increases to Rider EE's rates, may be leading to the increase in eligible customer opt-outs. (*Id.* at 74.)

Witness Evans stated that to reduce opt outs, the Company continues to evaluate and revise its non-residential portfolio of programs to accommodate new technologies, eliminate product gaps, remove barriers to participation, and make its programs more attractive to opt-out eligible customers. (*Id.* at 73.) It also continues to leverage its Large Account Management Team to make sure customers are informed about product offerings and their ability to opt into the Company's DSM and/or EE offerings during the March opt-in window. (*Id.* at 74-75.)

NC Justice Center, *et al.*, witness Bradley-Wright gave DEC "high marks" for its DSM/EE performance and testified that DEC continues to be a regional leader for EE in the Southeast. (*Id.* at 351.) He noted that for the two previous years the Company has exceeded a one percent savings mark. Witness Bradley-Wright reported that in 2019, DEC delivered 794.9 gigawatt-hours (GWh) of efficiency savings at the meter, equal to 0.98% of the previous year's retail sales, reflecting a 2% decline in incremental savings from 2018. (*Id.* at 355.) Savings from low-income efficiency programs were 30% higher than in 2018, however. Witness Bradley-Wright also noted that a further 10% decline in savings was projected for 2021. (*Id.* at 356-361.)

To address the projected decline in savings, witness Bradley-Wright made several recommendations. First, he recommended that the Commission direct the Company to provide specific documentation explaining any projected decline in savings in the future and how the Company intends to prevent such declines in future DSM/EE proceedings. (*Id.* at 363.) Witness Bradley-Wright next recommended that the Commission endorse the goal of achieving higher savings for low income customers, supported by increased budgets. He testified that the Company should submit a plan to the Commission to both increase low income efficiency savings levels overall and deliver efficiency savings to customers who struggle with high energy burdens. (*Id.* at 366-67.) Witness Bradley-Wright also recommended that the Commission include energy efficiency in the state's response to the coronavirus pandemic. To that end, he urged the Commission to direct the Company to present a plan to increase efficiency assistance to customers suffering from the current economic downturn and to address the program delivery challenges resulting from the coronavirus pandemic. (*Id.* at 367.)

With respect to the Collaborative, witness Bradley-Wright described the progress of the Collaborative over the past year. Witness Bradley-Wright focused on the work to expand energy efficiency savings to low income customers. He further discussed that portion of the Commission's 2019 order wherein the Commission concluded that it would be helpful to have the Collaborative examine the reasons for the Company's forecasted savings decline and how to prevent the decline in future proceedings. He further recommended that the members of the Collaborative work with Company representatives to prepare a report before the next DSM/EE recovery rider proceeding. (*Id.* at 367-372.)

Witness Bradley-Wright concluded his testimony by addressing a number of policy and regulatory matters relating to DEC's energy savings achievements and efforts to cut carbon emissions in North Carolina. Included in that discussion were integrated resource planning, DSM/EE program applications, rate cases and performance incentive mechanism review. (*Id.* at 380-392.)

In his rebuttal testimony, DEC witness Evans responded to witness Bradley-Wright's testimony regarding the Collaborative. He disputed what he believed was witness

Bradley-Wright's implication that DEC's projected decline in savings was a result of a lack of effort. Rather, witness Evans explained, the projected decline reflected market conditions and projected participation. Witness Evans confirmed that the Company continues to seek opportunities for new and improved programs. Witness Evans also cautioned against setting higher savings projections to indicate the Company aspires to higher achieved savings. According to witness Evans, projections are used to set rates; therefore, the Company is conservative in its projections to avoid raising rates and over collecting from customers. The projections, witness Evans noted, are not a cap on savings. (*Id.* at 84-86.)

Witness Evans testified that because the Company had launched a corporate strategy to address the needs of customers during the pandemic, a strategy specific to EE programs was not necessary. The corporate plan included a moratorium on disconnections and suspension of reconnection fees. Additionally, the Duke Foundation provided financial support for food banks and agencies to provide bill assistance. Although the Company has had to suspend programs that require in-home consultations, it has updated its customer communications with more tips about working from home. Consequently, witness Evans concluded a specific EE plan was not necessary. (*Id.* at 85-86.)

Witness Evans opposed NC Justice Center, *et al.*, witness Bradley-Wright's recommendation that the Commission request a report directly from the Collaborative. He noted that the Collaborative was formed by the Commission in Docket No. E-7, Sub 831 as an advisory group to provide "an important forum for Duke to receive input from a variety of stakeholders." Witness Evans opined that if any of the Collaborative members want to communicate with the Commission, they can do so through future interventions, and that assigning a written report for members of the Collaborative to complete is not necessary when organizations have chosen not to intervene. (*Id.* at 86.)

Conclusions

The Commission has fully reviewed the issues raised and recommendations made by NC Justice Center, *et al.*, witness Bradley-Wright, and concludes the following:

(1) The forecasted decline in DEC's DSM/EE savings in 2021 is a matter of concern. Consequently, the Collaborative should examine the reasons for the forecasted decline and continue exploring options for preventing or correcting a decline in future DSM/EE savings.

(2) The Collaborative should continue to place emphasis on developing EE programs to assist low income customers in saving energy and to lessen their energy burdens.

(3) While the Company should focus on developing EE programs to assist low income customers to save energy, the Commission is not persuaded that the coronavirus pandemic necessitates requiring DEC to file a plan to increase efficiency assistance; however, the Commission calls upon DEC to continue efforts to benefit its customers

in the form of lessened energy burdens and report on those efforts in its 2021 DSM/EE rider application.

(4) In lieu of a report from the Collaborative as urged by NC Justice Center, *et al.*, the Company should continue reporting on Collaborative activities in its testimony filed in these proceedings. In addition, other parties are encouraged to address Collaborative activities through future interventions.

IT IS, THEREFORE, ORDERED as follows:

1. That with the exception of billing factors impacted by the disallowance of DEC's proposed 17% reserve margin adder, the Commission hereby approves the calculation of Rider EE as filed by DEC and revised in the Supplemental Testimony and Exhibits of Carolyn T. Miller, and the resulting billing factors as set forth in Supplemental Miller Exhibit 1, to go into effect for the rate period January 1, 2021 through December 31, 2021, subject to appropriate true ups in future cost recovery proceedings consistent with the Sub 1032 Order, the Sub 1130 Order, and other relevant orders of the Commission;

2. That DEC shall work with the Public Staff to calculate the impacted billing factors without DEC's proposed 17% reserve margin adder, and prepare a proposed Notice to Customers of the revised rate changes to be approved herein. Within 30 days from the date of this Order, the Company shall file for Commission approval of said revised billing factors and a proposed Notice to Customers, along with DEC's proposed time for sending the customer notice;

3. That DEC and the Collaborative participants shall give particular attention to the four directives stated by the Commission in this Order; and DEC shall include in its 2021 DSM/EE rider application a report on the progress made in satisfying the directives; and

4. That the combined DEC/DEP Collaborative shall continue to meet every other month.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of December, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Joann R. Snyder, Deputy Clerk

DOCKET NO. E-7, SUB 1231

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC,	)	ORDER APPROVING CPRE RIDER
for Approval of CPRE Cost Recovery Rider	)	AND CPRE PROGRAM
Pursuant to N.C.G.S. § 62-110.8 and	)	COMPLIANCE REPORT
Commission Rule R8-71	)	

HEARD: Tuesday, June 9, 2020, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Tuesday, June 9, 2020, at 1:00 p.m., remotely via WebEx

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

APPEARANCES:

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For North Carolina Sustainable Energy Association (NCSEA):

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For the Using and Consuming Public:

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BY THE COMMISSION: North Carolina General Statutes Section 62-110.8(g) and Commission Rule R8-71 require the Commission to conduct an annual proceeding to review costs incurred or anticipated to be incurred by an electric public utility to comply with the Competitive

Procurement of Renewable Energy (CPRE) Program pursuant to N.C.G.S. § 62-110.8 and an annual compliance report filed by the electric public utility pursuant to Rule R8-71(h).

On February 25, 2020, Duke Energy Carolinas, LLC (DEC or Company), filed an application pursuant to N.C.G.S. § 62-110.8 and Commission Rule R8-71 for Approval of CPRE Compliance Report and CPRE Cost Recovery Rider, along with the direct testimony and exhibits of Bryan L. Sykes, Rates and Regulatory Manager, and Phillip H. Cathcart, Compliance Manager with the Business & Compliance Department.

On March 17, 2020, 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.

Petitions to intervene were filed by CIGFUR on March 19, 2020; by NCSEA on March 23, 2020; and by CUCA on May 8, 2020. The Commission granted CIGFUR's petition to intervene on March 23, 2020, NCSEA's petition to intervene on March 24, 2020, and CUCA's petition to intervene on May 12, 2020. The intervention of the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On May 15, 2020, DEC filed the supplemental testimony and exhibits of witnesses Sykes and Cathcart. The supplemental testimony of witness Sykes presented revised rates reflecting the impacts related to four updates to numbers presented in his direct exhibits and workpapers, which resulted in lower customer rates for the billing period. The supplemental testimony of witness Cathcart included the DEC CPRE Compliance Report for calendar year 2019 as Cathcart Revised Exhibit No. 1.

On May 18, 2020, the Public Staff filed the testimony of Michael C. Maness, Director of the Public Staff Accounting Division, and Jeff Thomas, an engineer in the Public Staff Electric Division.

On May 28, 2020, DEC filed the rebuttal testimony of Bryan L. Sykes.

On May 29, 2020, the Commission issued an Order Scheduling Remote Hearings for Expert Witness Testimony due to the COVID-19 pandemic. All parties subsequently filed consent to remote hearings.

On June 2, 2020, DEC filed a motion to excuse all Company and Public Staff witnesses.

On June 4, 2020, the Commission issued an Order Granting Motion to Excuse Witnesses to excuse the DEC and Public Staff witnesses from appearing at the expert witness hearing and to allow the introduction into evidence of the prefiled testimony and exhibits of each witness at the evidentiary hearing.

On June 5, 2020, and June 25, 2020, DEC filed affidavits of publication indicating that the public notice had been provided in accordance with the Commission's procedural order.

The case came on for hearing as scheduled on June 9, 2020. The application, prefiled direct and supplemental testimonies, and workpapers and exhibits of DEC's witnesses and the testimony of the Public Staff's witnesses were received into evidence. No other party presented witnesses or exhibits, and no public witnesses appeared at the hearing.

On June 25, 2020, the Commission issued a notice requiring that briefs and proposed orders be filed by July 24, 2020.

On July 24, 2020, DEC and the Public Staff filed a joint proposed order. DEC and the Public Staff also both filed separate or additional findings of fact on the issue of cost allocation among the jurisdictions.

Based upon the Company's verified application, the testimony, workpapers and exhibits received into evidence at the hearing, and the record as a whole, the Commission makes the following

FINDINGS OF FACT

1. DEC is duly organized as a 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 Commission as a public utility. DEC is lawfully before this Commission based upon its application filed pursuant to N.C.G.S. § 62-110.8 and Commission Rule R8-71.

2. The test period for purposes of this proceeding is the 29 months ended December 31, 2019 (test period). The billing period for this proceeding is the 12-month period beginning September 1, 2020, and ending August 31, 2021.

3. In its application and its direct and supplemental testimony (including workpapers and exhibits) in this proceeding, DEC requested recovery of $1,138,297 of test period charges incurred to implement the CPRE Program. There were no purchased or generated power costs during the test period. The test period charges requested by DEC were used to determine its proposed Experience Modification Factor (EMF) rider and consisted solely of CPRE Program implementation costs experienced during the test period. DEC allocated 100% of the implementation charges to the North Carolina retail jurisdiction. Since this was the first CPRE Program rider filing made to comply with N.C.G.S. § 62-110.8 and Commission Rule R8 71, the full amount of test period charges was under-recovered.

4. The Company's implementation charges for the test period were reasonably and prudently incurred.

5. It is reasonable and appropriate to allocate system-level implementation costs to the North Carolina retail, South Carolina retail, and wholesale jurisdictions for purposes of calculating the rates for the Rider CPRE billing period and CPRE EMF test period rather than directly assigning 100% of the system-level CPRE Program implementation costs to North Carolina retail customers.

6. The North Carolina retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 58,622,538 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	22,444,481
General Service/Lighting	23,688,549
Industrial	12,489,508
Total	**58,622,538**

7. In its application and its direct and supplemental testimony (including exhibits) in this proceeding, DEC requested a total increase of $3,114,986, on a North Carolina retail basis, of billing period charges anticipated to be incurred for purchased and generated power and ongoing implementation costs.

8. The North Carolina retail jurisdictional allocation factors related to the capacity and energy components of purchased and generated power costs anticipated to be incurred during the billing period in this proceeding are 67.55% and 66.02%, respectively. The capacity component is based on 2019 peak demand, and the energy component is based on projected billing period sales. The North Carolina retail class allocation factors related to the capacity and energy components of purchased and generated power costs anticipated to be incurred during the billing period in this proceeding are based on peak demand and projected billing period kWh sales for each class, respectively. The North Carolina retail class allocation factors related to implementation charges anticipated to be incurred during the billing period and actually incurred during the test year (for purposes of calculating the EMF) are based on a composite rate calculated as the weighted average of the capacity and energy components of purchased and generated power.

9. The projected billing period sales for use in this proceeding are 58,460,089 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	Adjusted MWh Sales
Residential	22,067,951
General Service/Lighting	23,951,115
Industrial	12,441,023
Total	**58,460,089**

10. DEC's experienced North Carolina retail under-recovery of costs for the extended initial test period, or EMF period, the 29-month period starting August 1, 2017, and ending December 31, 2019, amounts to $754,459, excluding the regulatory fee, as set forth on Maness

Exhibit 1. DEC under-recovered its CPRE EMF costs for the extended initial test period by $294,856 for the Residential class, $305,678 for the General Service/Lighting class, and $153,926 for the Industrial class.

11. The appropriate monthly CPRE EMF rates to be charged to customers are 0.0013 cents per kWh for the Residential class, 0.0013 cents per kWh for the General Service/Lighting class, and 0.0012 cents per kWh for the Industrial class, excluding the regulatory fee.

12. The appropriate North Carolina retail prospective billing period expenses, as adjusted and set forth on Maness Exhibit 1, amounted to a total of $2,985,320. The appropriate prospective billing period expenses for use in this proceeding are $1,166,715 for the Residential class, $1,209,536 for the General Service/Lighting class, and $609,069 for the Industrial class.

13. The appropriate monthly prospective CPRE Rider rates to be charged to customers are 0.0054 cents per kWh for the Residential class, 0.0051 cents per kWh for the General Service/Lighting class, and 0.0049 cents per kWh for the Industrial class, excluding the regulatory fee.

14. The appropriate combined monthly EMF and CPRE Rider rates to be collected during the billing period are 0.0067 cents per kWh for the Residential class, 0.0064 cents per kWh for the General Service/Lighting class, and 0.0061 cents per kWh for the Industrial class, excluding the regulatory fee.

15. The increase in costs the Company proposes to recover with its proposed EMF and CPRE Riders is within the limit established in N.C.G.S. § 62-110.8.

16. DEC is reasonably and prudently implementing the CPRE Program requirements of N.C.G.S. § 62-110.8.

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

The evidence for this finding of fact is contained in the testimony and exhibits of Company witnesses Sykes and Cathcart.

Witness Sykes testified that N.C.G.S. § 62-110.8 provides that an electric public utility shall be authorized to recover the costs of all purchases of energy, capacity, and environmental and renewable attributes from third-party renewable energy facilities and to recover the authorized revenue of any utility-owned assets that are procured through an annual rider approved by the Commission and reviewed annually. Commission Rule R8-71 prescribes that unless otherwise ordered by the Commission, the test period for each electric public utility shall be the same as its test period for purposes of Rule R8-55. The test period for purposes of Rule R8-55 is the 12 months ending December 31. Witness Sykes testified that for the purposes of this proceeding, DEC's proposed rider includes both an EMF component to recover DEC's costs incurred during the test period as well as a component to collect costs forecasted to be incurred during the prospective 12-month period over which the proposed Rider CPRE will be in effect.

Witness Cathcart testified, however, that the Commission approved a modification to the Company's test period to be the 29-month period ending December 31, 2019, in its April 16, 2019 Order Cancelling Annual Public Hearing, Approving Proposed Accounting Treatment, and Approving CPRE Compliance Report in Docket No. E-7, Sub 1193.

Therefore, the Company's proposed test period in this proceeding is the 29 months beginning on August 1, 2017, and ending on December 31, 2019, and the billing period for Rider CPRE is the 12 months beginning on September 1, 2020, and ending on August 31, 2021.

The test period and the billing period proposed by DEC were not challenged by any party. Based on the foregoing, the Commission concludes the Company used the appropriate test period and billing period for this first Rider CPRE filing.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3–4

The evidence for these findings of fact is contained in the testimony and exhibits of Company witnesses Sykes and Cathcart and the testimony and exhibits of Public Staff witnesses Thomas and Maness.

On his Revised Exhibit No. 2, Company witness Sykes set forth the per books implementation charges of $1,138,297 incurred by the Company to establish the CPRE Program and the amount of under-collection for purposes of the EMF. Company witness Cathcart testified regarding the Company's actions to implement the CPRE Program and comply with the CPRE Program requirements of N.C.G.S. § 62-110.8, as described in the Company's 2019 CPRE Compliance Report. The Commission takes judicial notice of the Company's compliance report for calendar year 2018 as filed in Docket No. E-7, Sub 1193. In his calculation of the proposed EMF, witness Sykes allocated 100% of the implementation charges to the North Carolina retail jurisdiction.

The testimony of Public Staff witness Thomas attested to the system-level expenses sought for recovery during the test period. Witness Thomas did not recommend any adjustments to the system-level expenses.

The testimony of Public Staff witness Maness describes procedures taken by the Public Staff to evaluate whether the Company properly determined its per books CPRE Program costs and revenues during the test period. Witness Maness did not recommend any adjustments to the system level of per books costs.

No party challenged the prudency of the per books amount of $1,138,297 which the Company is seeking to recover.

The Commission concludes the $1,138,297 per books system-level costs incurred by the Company during the test period to implement the CPRE Program were reasonably and prudently incurred and are appropriate to be recovered by the Company.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is found in the application; the direct, supplemental, and rebuttal testimony and exhibits of Company witness Sykes; and the testimony and exhibits of Public Staff witnesses Thomas and Maness.

In its application and the testimony of witness Sykes, DEC proposed to allocate 100% of the implementation costs of the CPRE Program to North Carolina retail customers rather than to all jurisdictional customers consistent with how it allocates CPRE Program energy and capacity costs. Sykes Revised Exhibits 3 and 4. In direct testimony, witness Sykes stated that the Company has directly assigned the reasonable and prudent implementation costs incurred and anticipated to be incurred to implement its CPRE Program and to comply with N.C.G.S. § 62-110.8 and Rule R8-71(j)(2) to its North Carolina retail customers consistent with cost causation principles. Tr. vol. 2, 19.

Public Staff witnesses Thomas and Maness recommended an adjustment to DEC's proposed allocation of CPRE Program implementation costs incurred during the Company's extended initial test period and projected to be incurred in the billing period to include South Carolina retail and wholesale customers. The CPRE Program implementation costs include internal labor and labor-related taxes and benefits, external consulting, independent administrator costs, and transmission and distribution (T&D) sub-team labor and labor-related costs in excess of fees collected from market participants. *Id.* at 64.

When asked why the Company did not allocate the costs between North Carolina and South Carolina retail and wholesale customers, witness Thomas stated that the Company in response to a data request, stated, "the CPRE Program was mandated by the General Assembly of North Carolina, and as such, the Company believes it reasonable that its implementation costs should be directly assigned to its NC Retail customers." *Id.* Witness Thomas further stated that the Company considers its treatment of the costs as similar to how it treats costs incurred to comply with the North Carolina Renewable Energy and Energy Efficiency Portfolio Standards (REPS) Program and the South Carolina Distributed Energy Resource Program (SC DERP). *Id.*

Witness Thomas disagreed with the Company's rationale for the proposed allocation and recommended that the implementation costs be allocated to North Carolina and South Carolina retail and wholesale customers in same manner as energy and capacity costs. *Id.* at 65. Witness Thomas argued that there are significant differences between the CPRE Program and the REPS and SC DERP programs. The CPRE Program provides system power to all jurisdictions at or below avoided costs. Meanwhile the REPS Program, pursuant to N.C.G.S. § 62-133.8(h), authorizes a utility to recover the incremental costs of compliance, including all reasonable and prudent costs in excess of the utility's avoided costs, from its North Carolina retail customers. The SC DERP similarly authorizes the utility to recover the incremental costs above avoided costs resulting from implementation of the SC DERP from its South Carolina retail customers. *Id.* at 66.

Additionally, witness Thomas noted that the CPRE Program expressly requires renewable energy to be competitively procured from within the utilities' respective balancing authority areas, "whether located inside or outside the geographic boundaries of the State," while taking into consideration factors that are designed to ensure the most cost-effective projects are selected across each utility's service area. *Id.* at 66 (quoting N.C.G.S. § 62-110.8(c)).

Witness Thomas testified that to date the CPRE Program has selected the most cost-effective facilities in both North Carolina and South Carolina. According to the Independent Administrator's report, Tranche 1 projects are estimated to save DEC customers over $200 million relative to DEC's avoided cost over the next 20 years. *Id.* at 66-67. In comparison, both North Carolina's REPS Program and SC DERP procures renewable energy at prices above avoided cost, imposing a premium on DEC customers.

In rebuttal testimony, DEC witness Sykes stated that the Company's proposal to allocate implementation costs to North Carolina retail customers is consistent with both general cost causation principles and the manner in which program implementation costs have historically been allocated in connection with North Carolina REPS and SC DERP. *Id.* at 26.

With regard to energy and capacity costs, witness Sykes testified that renewable energy resources procured through the CPRE Program will be supply-side system resources and will be used to supply electricity to the Company's retail and wholesale customers. Thus, it is appropriate to allocate those costs to all customers. In contrast, witness Sykes argued, the CPRE Program implementation costs should be allocated to North Carolina retail customers because they are costs caused solely by the Company's obligation to comply with N.C.G.S. § 62-110.8 and Commission Rule R8-71. Witness Sykes testified further, "Stated differently, the implementation costs would not have been incurred 'but for' the requirements of N.C. Gen. Stat. § 62-110.8 and Commission Rule R8-71, in contrast with the energy and capacity costs which would have incurred on a system basis even in the absence of the CPRE program." *Id.* at 27.

Witness Sykes added that the Company's allocation of implementation costs has not historically been based on assessment of whether those costs should be considered as part of the portion of energy and capacity costs that are above or below avoided costs. Further, the existence of costs above avoided costs associated with a particular program should not take precedence over cost causation principles and become the determinative factor for assignment of implementation costs. In conclusion, witness Sykes testified that the Company continues to believe that incremental costs that are specific to the statutory requirements of a particular state are appropriately assigned to that state's retail customers.

After consideration of this issue, the Commission concludes that the adjustment recommended by Public Staff witnesses Thomas and Maness to allocate CPRE Program implementation costs to all jurisdictional customers produces a more reasonable and appropriate outcome than the proposal by the Company to allocate the implementation costs solely to North Carolina retail customers. Although the costs in question were incurred pursuant to North Carolina law establishing the requirement for the competitive procurement of renewable resources, the costs are inherently related to the procurement of renewable energy and capacity to serve the entire DEC system, including South Carolina and wholesale customers, at or below avoided cost.

The CPRE Program was developed and approved by the Commission pursuant to N.C.G.S. § 62-110.8 with the objective of procuring renewable energy to provide system benefits to customers at the lowest cost. Through the completion of Tranche 1, the winning projects are estimated to save all DEC customers over $200 million relative to DEC's avoided costs. *Id.* at 67 (citing Final Report of the Independent Administrator Re: Request for Proposals for the Competitive Procurement of Renewable Energy Program Tranche 1, Figure 1 (July 18, 2019) (filed as Appendix A of DEC's 2019 CPRE Compliance Report, Cathcart Exhibit No. 1)). Stated another way, "but for" the implementation of the CPRE program, all of DEC's customers — including DEC's South Carolina retail customers — would be paying more for the energy and capacity, which DEC acknowledges would have been purchased even in the absence of the CPRE program.

The Company argues that the costs of implementation of the CPRE Program should be directly assigned to North Carolina customers because they are a result of North Carolina law. While the CPRE Program was developed and implemented pursuant to North Carolina law and Commission rule, the Commission agrees with the Public Staff that it would be inequitable and unreasonable to assign all the implementation costs to North Carolina retail customers as the CPRE Program provides benefits to South Carolina and wholesale customers from direct renewable energy investments, low-cost power, and the experience gained by DEC in establishing a robust competitive procurement program. *Id.* at 67.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is contained in the testimony and exhibits of DEC witness Sykes and Public Staff witness Maness.

In his Revised Exhibit No. 4, DEC witness Sykes provided DEC's normalized North Carolina retail sales for EMF purposes of 22,444,481 MWh for the Residential class; 23,688,549 MWh for the General Service/Lighting class, and 12,489,508 MWh for the Industrial class.

Public Staff witness Maness noted these values in his testimony and stated that he did not propose any adjustments to the test period sales amounts used in this proceeding.

No other party presented evidence on the appropriateness of test period North Carolina retail sales.

The Commission concludes that the test period North Carolina retail MWh sales proposed by the Company and agreed to by the Public Staff for purposes of calculating the EMF billing factors are appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7–8

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Sykes and Public Staff witness Thomas.

DEC witness Sykes presented in his Revised Exhibit Nos. 2 and 3 DEC's projected CPRE Program costs in the billing period and the allocation of those costs to the North Carolina retail jurisdiction and the North Carolina retail customer classes. The Company used the 2019 peak demand jurisdictional allocation factor of 67.55% for capacity costs and the projected billing period sales jurisdictional allocation factor of 66.02% for energy costs for its allocation of CPRE Program purchased and generated power costs.

Public Staff witness Thomas stated that the Public Staff investigated DEC's estimation of system-level billing period costs and found them generally reasonable. Witness Thomas further stated that the Company's estimation of total energy production for each CPRE facility is based on two generic output profiles and that the Company used the actual bid prices from each project's Power Purchase Agreement (or, in the case of utility-owned projects, the as-bid price) to estimate total costs.

Witness Thomas further testified that the Public Staff does not take exception to the use of the 2019 peak demand jurisdictional allocation factor of 67.55% for capacity costs and the projected billing period sales jurisdictional allocation factor of 66.02% for energy costs for its jurisdictional allocation of CPRE Program purchased and generated power costs. The Public Staff also does not oppose the use of peak demand and energy sales, respectively, to allocate North Carolina retail jurisdictional capacity and energy costs to the customer classes (for both anticipated billing period costs and actual test period costs).

Public Staff witness Thomas also addressed the Company's use of a composite rate for allocating North Carolina retail implementation charges to the North Carolina retail customer classes. The Public Staff does not take exception to the use of a composite rate but does challenge the Company's proposed allocation of 100% of implementation costs to the North Carolina retail jurisdiction, as discussed in Finding of Fact No. 5.

No other party presented evidence on the appropriateness of the Company's proposed billing period charges anticipated to be incurred or the allocation of these costs.

The Commission concludes that the Company's system-level charges anticipated to be incurred during the billing period for purchased and generated capacity and energy and ongoing implementation costs is appropriate for use in this proceeding. The Commission further concludes that the use of 67.55% for the capacity component and 66.02% for the energy component to allocate system-level CPRE Program purchased and generated power costs to the North Carolina retail jurisdiction is appropriate for use in this proceeding and that the use of peak demand and energy sales, respectively, to allocate North Carolina retail jurisdictional capacity and energy costs to the customer classes is appropriate for use in this proceeding (for both anticipated billing period costs and actual test period costs). Further, the Commission concludes that the use of a composite rate for the allocation of North Carolina retail implementation costs to the North Carolina retail customer classes is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is contained in the testimony and Revised Exhibit No. 3 of Company witness Sykes and Public Staff witness Thomas.

In his Revised Exhibit No. 3, DEC witness Sykes provided DEC's projected billing period sales of 22,067,951 MWh for the Residential class, 23,951,115 MWh for the General Service/Lighting class, and 12,441,023 MWh for the Industrial class. Witness Sykes further testified that the Rider CPRE rate per customer class for purchased and generated power is determined by dividing the sum of the billing period costs allocated to the class by the forecast billing period MWh sales for the customer class. Similarly, the Rider CPRE rate per customer class for implementation costs is determined by dividing the sum of the billing period costs allocated to the class, using a composite rate determined in the purchased and generated power calculation, above, by the forecast billing period MWh sales for the customer class.

Public Staff witness Thomas testified as to the Company's request to recover capacity and energy costs based upon its projected billing period sales. Public Staff witness Thomas did not propose any adjustments to the projected billing period sales amounts used in this proceeding.

No other party presented evidence on the appropriateness of projected billing period North Carolina retail sales.

The Commission concludes that the Company's projected billing period sales for North Carolina retail customer classes is as follows: 22,067,951 MWh for the Residential class, 23,951,115 MWh for the General Service/Lighting class, and 12,441,023 MWh for the Industrial class.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10–14

The evidence supporting these findings of fact appears in DEC's Application, in the direct and supplemental testimony and exhibits of DEC witness Sykes, and in the testimony and exhibits of Public Staff witnesses Thomas and Maness.

Witness Sykes' revised exhibits show a total $1,138,297 under-recovery of CPRE Program costs for the EMF period, the initial test period starting August 1, 2007 and ending December 31, 2019. The prospective CPRE Program costs for the billing period, as shown through witness Sykes' revised exhibits, amounted to a total of $3,114,986.

In supplemental testimony, witness Sykes revised the components of the proposed Total CPRE Rate to be effective September 1, 2020, and to remain in effect for the 12-month billing period ending August 31, 2021, as follows, excluding the regulatory fee:

DEC's Rider Request Filed on May 15, 2020 (cents per kWh)

Customer Class	EMF Rate	CPRE Rider Rate	Total CPRE Rate
Residential	0.0020	0.0056	0.0076
General Service/Lighting	0.0019	0.0054	0.0073
Industrial	0.0019	0.0051	0.0070

Public Staff witnesses Thomas and Maness testified that they reviewed and analyzed the CPRE Program costs for which DEC has requested recovery in this proceeding, and with the exception of the CPRE Program implementation costs discussed in Finding of Fact No. 5, found them to be appropriate.

Witness Maness testified that the Public Staff's investigation included procedures intended to evaluate whether the Company properly determined its per books CPRE Program implementation costs and revenues during the test period. He stated that these procedures included a review of the Company's filing and other Company data provided to the Public Staff. Witness Maness testified that performing the Public Staff's investigation required the review of numerous responses to written and verbal data requests as well as discussions with the Company. *Id.* at 89.

After reviewing all of DEC's testimony and exhibits, the Public Staff, through the testimony of witnesses Thomas and Maness, recommended that DEC allocate CPRE Program implementation costs to its North Carolina and South Carolina retail and wholesale customers and refile its witness Sykes' exhibits reflecting this change. The Public Staff did not recommend any adjustments to the system-level extended initial test period or billing period costs sought for recovery. *Id.* at 81, 90.

Based on the discussion in Finding of Fact No. 5, the Commission agrees with the Public Staff's proposed adjustments to DEC's CPRE EMF and prospective billing period costs, as presented in Maness Exhibit 1, to allocate CPRE Program implementation costs to North Carolina and South Carolina retail and wholesale customers.

Thus, the Commission finds it appropriate to calculate the CPRE EMF using the North Carolina retail portion of the CPRE Program implementation costs, which total $754,459 under-recovery for costs in the EMF period, as set forth on Maness Exhibit 1. Witness Maness testified that DEC under-recovered its CPRE EMF costs for the extended initial test period by $294,856 for the Residential class, $305,678 for the General Service/Lighting class, and $153,926 for the Industrial class.

The Commission finds it appropriate to calculate the CPRE Rider Rate using the North Carolina retail portion of the CPRE Program implementation costs. The prospective CPRE Program costs for the billing period, as adjusted and set forth on Maness' Exhibit 1, amounted to a total of $2,985,320. Witness Maness testified that the prospective billing period expenses for use in this proceeding are $1,166,715 for the Residential class, $1,209,536 for the General Service/Lighting class, and $609,069 for the Industrial class.

As presented in Public Staff witness Thomas' testimony and supported by witness Maness Exhibit 1, the combined EMF Rate and CPRE Rider Rate charges per customer account, excluding the regulatory fee are as follows:

Public Staff's Recommended Rates (cents per kWh)

Customer Class	EMF Rate	CPRE Rider Rate	Total CPRE Rate
Residential	0.0013	0.0054	0.0067
General Service/Lighting	0.0013	0.0051	0.0064
Industrial	0.0012	0.0049	0.0061

The Commission finds the Public Staff's recommended adjustment to rates just and reasonable for purposes of this proceeding. Based on the Commission's findings in this proceeding, it is appropriate that DEC file with the Commission updated EMF rates CPRE Rider rates consistent with the rulings in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Sykes.

DEC witness Sykes testified that N.C.G.S. § 62-110.8(g) limits the annual increase in costs recoverable by an electric public utility to (1%) of the electric public utility's total North Carolina retail jurisdictional gross revenues for the preceding calendar year. Further, he testified that Rule R8-71 provides that "[t]he annual increase in the aggregate costs recovered under N.C.G.S. § 62-110.8(g) in any recovery period from its North Carolina retail customers shall not exceed one percent (1%) of the electric public utility's North Carolina retail jurisdictional gross revenues for the preceding calendar year as determined as of December 31 of the previous calendar year." Witness Sykes testified that the increase in aggregate costs DEC seeks to recover in this proceeding is less than the statutory maximum.

Public Staff witness Thomas similarly concluded that the costs the Company seeks to recover are less than 1% of DEC's total North Carolina retail jurisdictional gross revenues for 2019.

The Commission concludes that the costs the Company seeks to recover in this proceeding are not in excess of the cost cap established by N.C.G.S. § 62-110.8(g).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding of fact is contained in the direct and supplemental testimony and exhibits of Company witness Cathcart, including the 2019 CPRE Compliance Report.

Witness Cathcart and the 2019 CPRE Compliance Report detail the actions of the Company to implement the CPRE Program requirements of N.C.G.S. § 62-110.8. The 2019 CPRE Compliance Report describes the Company's efforts to implement the CPRE Program in collaboration with the Independent Administrator (IA). The IA's Final Report for Tranche 1 (Final Report) was included as Appendix A to the 2019 CPRE Compliance Report and provides substantial details regarding the Tranche 1 process and outcome. The Company was ultimately able to procure 10 projects totaling 435 MW at prices well below the avoided cost cap, resulting in substantial projected savings to customers relative to avoided costs.

The Final Report also describes the Company's efforts, along with the IA, to identify areas of improvements for Tranche 2, and the 2019 CPRE Compliance Report provides further details regarding the Company's plans for Tranche 2. The 2019 CPRE Compliance Report also includes all of the information required by Commission Rule R8-71(h), including a description of the CPRE Program solicitation undertaken by DEC during the reporting year, the avoided cost rates applicable to Tranche 1, confirmation that all renewable energy resources procured through Tranche 1 were priced at or below avoided costs, certification by the IA that all public utility and third-party proposal responses were evaluated under the published CPRE Program methodology and that all proposals were treated equitably in Tranche 1 during the reporting year. The Commission takes judicial notice of the Company's compliance report for calendar year 2018 as filed in Docket No. E-7, Sub 1193.

The Public Staff did not challenge the reasonableness and prudence of the Company's implementation of the CPRE Program requirements of N.C.G.S. § 62-110.8. No other party presented evidence on this issue.

Therefore, the Commission concludes that the Company is in compliance with and has reasonably and prudently implemented the CPRE Program requirements of N.C.G.S. § 62-110.8.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC's request to establish a CPRE Rider is approved and that this rider shall remain in effect for a 12-month period beginning on September 1, 2020 and expiring on August 31, 2021;

2. That DEC's request to establish an EMF Rider is approved and that this rider shall remain in effect for a 12-month period beginning on September 1, 2020 and expiring on August 31, 2021;

3. That DEC shall file the appropriate rate schedules and riders with the Commission in order to implement the provisions of this Order and amounts approved herein, as soon as practicable, but not later than ten days after the date of this Order;

4. 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 Nos. E-7, Sub 1228 and E-7, Sub 1229, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten days after the Commission issues orders in all three dockets; and

5. That DEC's 2019 CPRE Compliance Report is hereby approved.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of August, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy 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.CG.S. § 62-133.2 and Commission Rule R8-55 Regarding Fuel and Fuel-Related Cost Adjustments for Electric Utilities	)	ORDER ALLOWING RECOVERY OF LIQUIDATED DAMAGES AND TRANSPORATION COSTS

HEARD: Tuesday, March 10, 2020, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chair Charlotte A. Mitchell, Presiding; Commissioners ToNola D. Brown-Bland, Lyons Gray, and Daniel G. Clodfelter

APPEARANCES:

For Duke Energy Progress, LLC:

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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 September 9 and 10, 2019, the Commission held the first hearing in this matter. On November 25, 2019, the Commission issued an Order Approving Interim Fuel Charge Adjustment, Requiring Further Testimony, and Scheduling Hearing (Interim Order). In summary, the Interim Order approved fuel charge adjustments to be implemented by DEP effective December 1, 2019, but withheld for a future decision the question of whether DEP would be allowed to recover from ratepayers the actual damages and liquidated damages being paid by DEP to CertainTeed Gypsum NC, Inc. (CTG), based on a judgment for breach of contract entered against DEP in the North Carolina Business Court. The Interim Order required the Public Staff to file supplemental direct testimony and DEP to file supplemental rebuttal testimony on the CTG issue, and scheduled a hearing on the issue to be held on March 10, 2020.

On January 17, 2020, the Public Staff filed supplemental direct testimony and exhibits of Jay B. Lucas.

On February 17, 2020, DEP filed joint supplemental rebuttal testimony and exhibits of Barbara Coppola and John Halm, and supplemental rebuttal testimony of John Gaynor.

On March 10, 2020, the case came on for hearing as scheduled.

On April 20, 2020, the Public Staff filed its Proposed Findings of Fact and Conclusions of Law.

Also on April 20, 2020, DEP filed a Post-Hearing Brief.

On May 28, 2020, the Commission issued an Order Requiring Filing of Post-Hearing Exhibit directing DEP to file with the Commission on or before June 3, 2020, an affidavit that was filed by witness Halm in the North Carolina Business Court. On June 1, 2020, DEP filed witness Halm's affidavit.

The Commission incorporates herein by reference the findings of fact and conclusions of the Interim Order. For purposes of clarity, the findings of fact pertaining to the CTG issue are set forth below.

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.

Based on the Interim Order, the evidence presented at the March 10, 2020 hearing, and the record as a whole, the Commission makes the following:

ADDITIONAL FINDINGS OF FACT

Background

1. When CTG and DEP entered into the initial gypsum supply agreement in 2004 (2004 Agreement), DEP was planning to install flue gas desulfurization systems (scrubbers) that would produce synthetic gypsum at its Roxboro and Mayo coal-fired plants (Roxboro Plants), and CTG was planning to build its first wallboard manufacturing plant in the southeast United States.

2. The 2004 Agreement defined the monthly minimum quantity (MMQ) of gypsum that DEP would deliver and CTG would accept as 50,000 net dry tons of gypsum (Fixed MMQ). The Fixed MMQ level was based on what DEP was willing to provide over the life of the agreement.

3. DEP did not deliver gypsum to CTG and CTG did not accept gypsum under the 2004 Agreement, primarily due to the decline in the housing market that resulted from the 2008 economic downturn.

4. In 2008 the parties executed an amended agreement (2008 Agreement) following CTG's decision to delay construction of its plant because of the 2008 economic downturn. Under the 2008 Agreement, CTG was required to accept and DEP was required to deliver the Fixed MMQ of 50,000 net dry tons of gypsum.

5. The Roxboro Plant scrubbers began coming on-line in spring 2007. Every six months an additional scrubber came on line at each of the five units at Roxboro and Mayo, with the final scrubber coming on line in the spring of 2009.

Negotiations Leading to the 2012 Agreement

6. Between June 2011 and February 2012, DEP witness Coppola and CTG employee Dave Engelhardt, Senior Vice President of Operations, negotiated a revised contract that replaced the 2008 Agreement (2012 Agreement).

7. In 2011 there were several facts that caused CTG to want to renegotiate the 2008 Agreement, including:

(a) CTG had accepted no gypsum from DEP from execution of the 2004 Agreement until May 2009;
(b) The Great Recession of 2008 had demonstrated to CTG its vulnerability to a downturn in the housing market;
(c) CTG had experienced delays in construction of its manufacturing plant, with commercial operation not anticipated until approximately October 2012;
(d) During the period of 2008 to 2012, CTG accepted gypsum in the amount equal to or above the Fixed MMQ in only six months; and
(e) CTG had paid $32 million to dispose of gypsum received under the 2008 Agreement in a landfill because it was unable to use it.

The above factors did not, however, change CTG's intent to retain the supply certainty that it had obtained and was in effect in the 2008 Agreement, particularly in light of the fact that CTG's plant was completed in March 2012 and production ramped up from that point in time.

CTG Redline and 2012 Agreement

9. In October 2011 Engelhardt sent DEP witness Coppola a possible revised contract as a redlined draft agreement (CTG Redline).

10. The CTG Redline that Engelhardt sent to Coppola proposed several changes to the terms of the 2008 Agreement, chief of which was to shift from a monthly focus to an annual minimum quantity requirement, with any default to be measured against the annual quantity. Further, under the CTG Redline, CTG would be obligated to accept DEP's actual production of gypsum or 600,000 net dry tons, whichever was less, and whatever amount of gypsum was necessary to guarantee that the stockpile did not exceed 600,000 net dry tons. In turn, DEP would

be required to maintain at least 100,000 net dry tons of gypsum in the stockpile at all times, irrespective of what DEP actually produced at Roxboro or Mayo.

11. DEC rejected the revisions proposed in the CTG Redline.

12. DEP and CTG executed the 2012 Agreement with an effective date of August 1, 2012. The 2012 Agreement required a Fixed MMQ of 50,000 net dry tons of gypsum per month, a minimum stockpile level of 250,000 net dry tons, and was effective through April 2029. The effect of the quantity terms in the 2012 Agreement was to require DEP to deliver a minimum annual quantity of 600,000 tons, just as the CTG Redline had proposed, albeit expressed in terms of a minimum monthly quantity over the course of each year.

13. Under the 2012 Agreement, as under the 2008 Agreement, CTG had the right to terminate the contract and collect liquidated damages from DEP if DEP failed to supply 50% of the 50,000 MMQ each month over a five year period or delivered less than 300,000 tons of gypsum per year in two consecutive years.

Prudency Review and Alternatives

14. In 2011 DEP had substantial information about the potential effects of lower natural gas prices, the JDA, and DEP's conversion to natural gas-fired generation on DEP's ability to supply CTG with 50,000 tons of gypsum a month from August 2012 through April 2029.

15. Based on the reasonably foreseeable effects of lower natural gas prices, the JDA, and DEP's conversion to natural gas-fired generation on DEP's ability to supply CTG with 50,000 tons of gypsum a month from August 2012 through April 2029, it would have been reasonable for DEP to further explore with CTG revising its delivery obligations prior to signing the 2012 Agreement.

16. Notwithstanding DEP's failure to explore other options with CTG, there was no reasonable likelihood that CTG would relinquish the supply certainty that it had secured in the 2004 and the 2008 Agreements.

17. If DEP had accepted the approach set forth in the CTG Redline it is reasonably likely that by 2018 or 2019 it would have had difficulty providing to CTG at least 300,000 tons of gypsum annually and would have been unable to both deliver a minimum of 300,000 tons of gypsum annually and also maintain a minimum stockpile at all times not less than 100,000 tons.

18. After entry of the Business Court Judgment it was reasonable and prudent for DEP to agree to pay CTG the contract damages ordered by the court and to exercise its right to terminate the 2012 Agreement and pay liquidated damages to CTG in consequence of such termination.

19. DEP is entitled to recover in its fuel rider the North Carolina retail portion of both the contract damages awarded by the Business Court and the liquidated damages resulting from DEP's subsequent termination of the 2012 Agreement.

EVIDENCE AND CONLUSIONS FOR FINDINGS OF FACT NOS. 1-5

The evidence supporting these findings and conclusions is contained in the direct and supplemental testimony and exhibits of Public Staff witness Lucas, the joint rebuttal and supplemental rebuttal testimony of DEP witnesses Coppola and Halm (collectively, DEP Panel), the Opinion and Final Judgment (Judgment) in the lawsuit between CTG and DEP, *CertainTeed Gypsum NC, Inc. v. Duke Energy Progress, LLC*, 17 CVS 395 (Person County), 2018 NCBC 90 (*CTG v. DEP*), introduced into the record as Fayetteville Public Works Commission (FPWC) Harrington Cross-Exam Exhibit 3.

With respect to the Business Court's Judgment, the Commission docs not rely on the court's findings of fact or conclusions in this Order. The Business Court's main inquiry was the intent of DEP and CTG in entering into the 2012 Agreement, and, specifically, whether they intended the 2012 Agreement to be a fixed quantity or a variable quantity supply contract. Based on extensive testimony, including testimony by Engelhardt, who did not testify before the Commission, the court concluded that the parties intended for the 2012 Agreement to require DEP to supply to CTG the Fixed MMQ of 50,000 tons per month. The Commission accepts that conclusion, but finds it only tangentially related to the Commission's main inquiry – whether DEP acted in a reasonable and prudent manner in entering into the 2012 Agreement in light of the changes in DEP's use of coal-fired generation and the alternatives available to DEP at the time. Therefore, the Commission determines that it is appropriate for the Commission to cite the Business Court's findings of fact where such findings provide useful, uncontroverted background information and where the Commission's findings of fact are corroborated by the court's findings.

Summary of the Evidence

In his supplemental testimony Public Staff witness Lucas testified that CTG and DEP first entered into a gypsum supply agreement in 2004. At that time, DEP was planning to install flue gas desulfurization systems (scrubbers) that would produce synthetic gypsum at its Roxboro and Mayo coal-fired plants, and CTG was seeking to build its first wallboard-manufacturing plant in the southeast United States. Tr. Vol. 3, 16. Witness Lucas testified that gypsum is a mineral that is the primary component of gypsum wallboard. It can be mined in its natural state but 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 Plants). Tr. Vol 2, 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 during the Business Court trial DEP witness Coppola testified that the scrubbers began coming on-line in spring 2007 at Roxboro; and that every six months an additional scrubber came on line at each of the five units at Roxboro and Mayo, with the final scrubber coming on line in the spring of 2009. Tr. Vol. 3, 17.

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 CTG's parent company for the future sale of artificial gypsum from the Roxboro Plants to CTG for the manufacture of gypsum board. Witness Lucas stated that in 2005 CTG acquired approximately 121 acres of land from DEP adjacent to the Roxboro plant with the intent of constructing a gypsum wallboard manufacturing facility. According to witness Lucas, CTG delayed construction of the wallboard manufacturing facility due to the housing market decline and economic downturn (Great Recession), and in late 2007 CTG contacted DEP in an effort to amend the 2004 Agreement and 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. Thereafter, beginning May 1, 2009, CTG began accepting artificial gypsum from DEP but transported it to other locations because the CTG facility adjacent to the Roxboro plant had not yet been completed. According to witness Lucas, the CTG facility at the Roxboro plant began operation on March 28, 2012. *Id.* at 62.

Witnesses Coppola and Halm testified that CTG was investing approximately $200 million to construct a wallboard production facility that was projected to operate for approximately 20-30 years, which required an assurance of a supply of gypsum sufficient to justify construction. Witnesses Coppola and Halm asserted that no rational investor would have been willing to make such a substantial investment without having an assurance of a cost-effective supply of gypsum that would be necessary to sustain operations. Tr. Vol. 3, 168.

Witnesses Coppola and Halm testified that in 2008 the parties executed an amended agreement (2008 Agreement) following CTG's decision to delay construction of its plant because of the 2008 economic downturn. *Id.* at 166. They further testified that from the very beginning of the transaction a minimum monthly delivery and acceptance obligation was included. Specifically, the 2004 Agreement contained a Minimum Monthly Quantity (Fixed MMQ) delivery and acceptance obligation of 50,000 tons, subject to 10% variation, which effectively resulted in an annual delivery and acceptance obligation of 600,000 tons per year. The DEP Panel testified that these obligations were carried forward into the 2008 Agreement. *Id.* at 167-68.

Conclusion

The Commission agrees with DEP witnesses Coppola and Halm and concludes that in 2004 and 2008, given the level of CTG's planned investment in the wallboard facility at Roxboro, CTG was pursuing a fixed monthly amount of gypsum for its future wallboard facility in order to obtain supply certainty.

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

The evidence supporting these findings of fact and conclusions is contained in the direct and supplemental testimony of Public Staff witness Lucas, the rebuttal and supplemental rebuttal testimony of Company witnesses Coppola and Halm, and the rebuttal testimony of Company witness John Gaynor.

Summary of the Evidence

Public Staff witness Lucas described the negotiation and execution of the 2012 Agreement in his supplemental testimony. According to witness Lucas, CTG's Dave Engelhardt testified during the Business Court trial that after 2008 CTG changed the design of its plants, specifically the feeding system, and needed to update the agreement to account for those changes. Witness Lucas testified that having observed the way CTG and DEP operated over the previous couple of years, Engelhardt had some thoughts on how to try to make the agreement more usable and build in some flexibility to cover variations. He had observed that production volumes on DEP's side varied and that CTG's demand for gypsum varied with the market for wallboard. Tr. Vol. 3, 17-18. Witness Lucas testified that Lucas Supplemental Exhibit 1 reflects the actual production volumes for Roxboro and Mayo for 2008-2012, and confirms that production volumes did in fact vary. In addition, DEP witness Halm testified that there were only about six months between 2008 and 2012 that CTG accepted the full Fixed MMQ of 50,000 tons. Tr. Vol. 3, 203.

During the hearing witness Lucas testified that after execution of the 2008 Agreement CTG realized it was not going to be able to meet its commitment to DEP to take the Fixed MMQ of gypsum. As examples of this realization, witness Lucas testified that CTG had accepted no gypsum from DEP under the 2004 Agreement, and that between 2008 and 2012 CTG had paid approximately $32 million to dispose of gypsum it could not use in its plant. Witness Halm corroborated this, testifying that in January 2010 CTG disposed of 80,000 tons of gypsum in a landfill in order to get it off the DEP stockpile because the stockpile was more than full, and the gypsum had to be removed for environmental and safety reasons. Tr. Vol. 3, 204. Thus, according to witness Lucas, between the 2008 and 2012 Agreement CTG had reasons to be cautious because it needed to maintain a balance between a minimum amount and a maximum amount of gypsum. Witness Lucas testified that it appeared that in October of 2011, once CTG was getting closer and closer to actually building a facility, that CTG realized it might not want 50,000 tons of gypsum per month. *Id.* at 53-55. However, he also agreed that the CTG facility at Roxboro did need a certain amount of gypsum to stay in business. *Id.* at 41, 47.

Witnesses Coppola and Halm testified that given that CTG already had certainty of supply under the 2008 Agreement, there was no reasonable scenario in which CTG would voluntarily waive its pre-existing minimum delivery rights and risk not being able to fully leverage its investment, particularly in light of the fact that there were no other economically viable sources of gypsum for CTG's Roxboro wallboard facility. They contended that this is supported by the conclusion of the Business Court that while CTG was willing to offer some monthly flexibility, it never intended to change the MMQ from the fixed volume of 50,000 net dry tons per month to a variable MMQ based on DEP's actual production at Roxboro and Mayo. Tr. Vol. 3, 179.

John Gaynor, a former employee of United States Gypsum (USG), testified that in his positions with USG he was responsible for procuring synthetic gypsum for USG and oversaw the procurement process, including contractual terms. His work also included developing new supply sources and agreements with power companies in connection with the development of three new greenfield wallboard plants. He stated that he reviewed the testimony of Public Staff witness Lucas, portions of the 2004 Agreement, the 2008 Agreement, and the 2012 Agreement. He also reviewed the CTG Redline (Coppola and Halm Supplemental Exhibit 1), and the Judgment. He concluded:

> 1. The flexibility offered by CTG in the context of the negotiations of the 2012 Agreement would not have excused DEP from satisfying the annual delivery obligation that was already in effect and would potentially have imposed an absolute minimum stockpile obligation.
>
> 2. The financial viability of the CTG manufacturing facility at Roxboro would have been highly dependent on an adequate supply of gypsum.

According to witness Gaynor, it is, therefore, reasonable and consistent with industry practice in similar situations that CTG would have obtained supply certainty from DEP in order to ensure that CTG could maximize production at its facility. Witness Gaynor further testified that once CTG had obtained supply certainty, as it did under the 2004 Agreement, and actually constructed the wallboard facility, he did not believe that CTG would have proposed or accepted any contract modification that would have materially reduced its long-term certainty of supply. Tr. Vol. 3, 254-255.

DISCUSSION AND CONCLUSION

The Commission gives substantial weight to witness Gaynor's testimony, based largely on his experience and expertise in the wallboard manufacturing industry. Further, the Commission agrees with his premise that the CTG manufacturing plant would be highly dependent on an adequate supply of gypsum, and that it is consistent with industry practice to obtain a regular and dependable supply of gypsum.

In its Post-Hearing Brief DEP contended that because of CTG's investment in the Roxboro wallboard plant and other commercial considerations, as discussed by witness Gaynor, CTG would not have considered any contract changes that would eliminate a requirement that DEP deliver at least 600,000 tons, measured annually, of gypsum. DEP Brief, at 17-18. According to DEP the basic premise of the 2011-2012 negotiations was that DEP would be unable to modify the annual minimum quantity requirement, even if it had been possible to negotiate some flexibility with respect to quantities delivered from month-to-month. The Commission accepts that premise, and concludes that it is not reasonably likely that CTG would have voluntarily relinquished the supply certainty that induced its original investment in the facility.

The Commission also gives weight to the particular facts of CTG's situation, which led to CTG's desire to negotiate in the 2011-2012 timeframe. Those facts included:

> (1) Having entered into the 2004 Agreement and a plan to build a wallboard plant at the Roxboro site, by 2008 CTG had accepted no gypsum from DEP, and its plant was not built. As a result, CTG and DEP negotiated a new contract, the 2008 Agreement;

(2) While working on its $200 million investment in the Roxboro plant, between 2008 and 2012 CTG paid approximately $32 million to dispose of gypsum it could not accept;

(3) The Great Recession of 2008 had demonstrated to CTG its vulnerability to a downturn in the housing market;

(4) In 2011, CTG's Roxboro plant was still not completed; and

(5) In 2011, CTG, for the second time in seven years, sought to renegotiate its contract with DEP.

Nonetheless, the above facts do not outweigh the fact that CTG invested $200 million in its wallboard manufacturing facility adjacent to DEP's Roxboro plant, an investment that was predicated on the 2004 and 2008 Agreements that provided CTG an assured supply of gypsum from DEP.

Based on the foregoing, the Commission finds and concludes that CTG had a reasonable business basis to maintain its entitlement under the 2004 and the 2008 Agreements to supply certainty. As a result, the starting point under which DEP and CTG were negotiating in 2011 was that CTG would require that same degree of supply certainty- 50,000 MMQ or a corresponding annual equivalent of 600,000 tons.

EVIDENCE AND CONLUSIONS FOR FINDINGS OF FACT NOS. 9-17

The evidence supporting these findings of fact and conclusions is contained in the Commission's dockets for the merger of Duke Energy Corporation and Progress Energy, Inc., Docket Nos. E-2, Sub 998 and E-7, Sub 986, the direct and supplemental testimony of Public Staff witness Lucas, the rebuttal and supplemental rebuttal testimony of Company witnesses Coppola and Halm, and the testimony of Engelhardt during the Business Court trial.

Summary of the Evidence

The DEP Panel and Public Staff witness Lucas testified to the negotiations between DEP and CTG from October 2011 through February 2012 on modifications to the 2008 Agreement. Public Staff witness Lucas testified that Engelhardt provided a list of proposed modifications to the 2008 Agreement entitled "Roxboro Stockpile Scenarios" (Roxboro Scenarios) to DEP witness Coppola. The Roxboro Scenarios were attached to witness Lucas' testimony as Confidential Lucas Supplemental Exhibit 2. The same document was entered into evidence during the Business Court trial as Exhibit 24. Witness Lucas testified that Engelhardt discussed the Roxboro Scenarios with witness Coppola. Tr. Vol. 3, 18; DEP Lucas Cross Examination Exhibit 4, p. 236 [Trial Transcript, Vol. 2].

During the Business Court trial Engelhardt stated that he was thinking about flexibility for CTG in the amount of gypsum that it had to accept and flexibility for DEP in the amount of gypsum that it had to supply when he prepared the Roxboro Scenarios. Trial Tr., Vol. 2, 136-37. According to Engelhardt, he tried to include the concepts of the Roxboro Scenarios in a draft redlined agreement (CTG Redline) that he sent to Company witness Coppola in October 2011. The CTG Redline was introduced into evidence in the Business Court as Exhibit 23, and before the Commission as DEP Supplemental Exhibit 1. The following is the exchange between Engelhardt and CTG's counsel regarding the timing of the Roxboro Scenarios and CTG Redline, and Engelhardt's testimony as to witness Coppola's response to them.

> Q. All right. So you sent Exhibit 23 [CTG Redline] to Ms. Coppola in October of 2011, correct?
>
> A. That's correct.
>
> Q. And what happened after that?
>
> A. Well, we -- I had sent her the scenarios as well. And we had a call -- I don't remember exactly -- maybe a week later, to discuss the scenarios page that I had sent her. And from then, there wasn't a lot of activity going back and forth. They were reviewing the contract. Barbara did tell me when we reviewed the scenarios that she preferred to stay with the contract -- the minimum monthly requirements and those numbers as they were stated in the 2008 agreement.
>
> Q. Take a look, if you would, at Exhibit 25, please, Mr. Engelhardt.
>
> A. Okay.
>
> Q. And are you familiar with this document?
>
> A. Yes.
>
> Q. And is this a series of emails between you and Ms. Coppola?
>
> A. Yes, it is
>
> Q. And in the email -- there's an email -- the first email at the bottom of the page is dated October 24, 2011. Do you see that?
>
> A. That's correct
>
> Q. That's 2 weeks after you sent her -
>
> A. Yes.
>
> Q. -- your draft; is that right?
>
> A. That's correct

Q. And does she make a statement in this agreement about what Duke would like to do with regard to the volumes?

A. Yes. She said: "In general, we would like to leave the volume obligation as is. We can discuss."

Q. All right. When did Duke respond to your October 2011 draft?

A. They sent a draft back in February of 2012.

Q. And after you had a conversation with Ms. Coppola in October about your scenarios, can you describe the level and nature of communication between Duke and CTG about this contract?

A. There really wasn't any -- any significant communications. We really never sat down and discussed any further -- after the scenarios discussion, we didn't really discuss anything further. There might have been one or two phone calls in there on "where are you, " "where do we stand on this, " but that would have been the extent of it.

Lucas Exhibit 4, pp. 157-59.

The October 24, 2011 email from witness Coppola that Engelhardt referenced was attached to witness Lucas' supplemental direct testimony as Confidential Lucas Supplemental Exhibit 3.

In response to questions from the Commission during the March 10, 2020 hearing, witness Coppola stated that she remembered receiving the Roxboro Scenarios and CTG Redline from Engelhardt in October 2011, and that there were numerous discussions around building some flexibility into the contract. Tr. Vol. 3, 210-12. However, in their supplemental rebuttal testimony Company witnesses Coppola and Halm asserted that in assessing whether it were imprudent for DEP to reject the majority of the changes proposed in the CTG Redline, it is necessary to understand the precise details of what CTG actually offered and to assess whether what CTG offered was better than what was already in effect. They explained that the delivery and acceptance obligations of the parties were measured in three distinct but related ways: (1) monthly delivery and acceptance quantifies, (2) annual delivery and acceptance quantities, and (3) minimum and maximum stockpile quantities. Tr. Vol. 3, 174.

Witnesses Coppola and Halm provided CTG's Redline changes as DEP Supplemental Exhibit 1 (introduced in the Business Court as Exhibit 23). According to witnesses Coppola and Halm, the modifications proposed by CTG were intended only to provide greater monthly variability but left in place the 600,000-ton annual quantity obligation and introduced new obligations related to DEP's obligation to maintain a minimum stockpile. They cited Finding of Fact No. 111 of the Judgment in which the Business Court concluded that CTG intended to allow for greater monthly variations while maintaining an annual quantity obligation and requiring a stockpile buffer. They opined that the reason CTG may have been interested in obtaining more flexibility with respect to the monthly delivery and acceptance obligations is that during the time period in which CTG's operations were ramping up, CTG was typically unable to accept enough gypsum to satisfy the MMQ. According to the DEP Panel, due to its contractual acceptance obligations CTG incurred more than $32 million disposing of gypsum that it was not able to receive and utilize at its facility. *Id.* at 174-75.

Witnesses Coppola and Halm stated that the CTG Redline proposed that DEP be obligated to maintain the stockpile at a minimum of 100,000 tons. They asserted that it would have been imprudent of the Company to accept CTG's proposed revisions because the proposal did not offer DEP significant advantages over the existing agreement – that is, it left in place a 600,000-ton annual delivery obligation and may have imposed obligations related to the stockpile that were potentially more onerous than those under the 2008 Agreement. Further, according to witnesses Coppola and Halm, even if DEP had accepted the CTG Redline exactly as proposed, DEP would still be in the exact same situation as it is today, and DEP would have been unable to satisfy the annual delivery requirements or maintain the minimum stockpile amounts without incurring substantial additional costs to obtain gypsum from sources other than the Roxboro and Mayo plants.. Further, they opined that DEP would still have had to exercise the right to discontinue supply and pay liquidated damages. *Id.* at 176-77.

Regarding the Roxboro Scenarios presented by the Public Staff as Lucas Confidential Supplemental Exhibit 2, witnesses Coppola and Halm contended that the Roxboro Scenarios represented an earlier iteration of CTG's perspective on possibilities related to delivery obligations. Witnesses Coppola and Halm asserted that like the CTG Redline the Roxboro Scenarios would have introduced a level of short-term flexibility while imposing firm obligations that were either the same or more onerous than was currently in effect under the 2008 Agreement. *Id.* at 177-78.

The 2012 Agreement was executed with an effective date of August 1, 2012. Tr. Vol. 3, 18-19. The 2012 Agreement was entered into evidence as Confidential FPWC Harrington Exhibit 1.[1]

In its Interim Order the Commission took note of the dates of several events described by witness Lucas in relation to the date that DEP entered into the 2012 Agreement. One such date was April 4, 2011, when Duke Energy Corporation and Progress Energy, Inc. filed the application for approval of their merger in Docket Nos. E-2, Sub 998 and E-7, Sub 986 (merger proceeding). The Commission further noted that attached to the merger application was a Joint Dispatch Agreement (JDA) (Exhibit 3), and that on June 29, 2012, the Commission issued its Order Approving Merger Subject to Regulatory Conditions and Code of Conduct (Merger Order). The Commission further observes that DEP employee Alexander Weintraub, who signed the 2012 Agreement, filed direct testimony on behalf of DEP on May 20, 2011, in the merger proceeding, and filed supplemental testimony on June 13, 2012.

[1] By letter dated April 20, 2020, the Public Staff informed the Commission that the Company agreed that the confidential designation for this document should be removed.

In his direct testimony Public Staff witness Lucas stated that under the JDA, which the companies entered into after the merger was approved, energy purchases between DEP and DEC are facilitated, thereby enabling the two companies to optimize the efficient dispatch of their combined generating fleets. Tr. Vol. 2, 63.

Also attached to the merger application, as Exhibit 4, was a Compass Lexecon Analysis of Economic Efficiencies Under Joint Dispatch (Compass Lexecon Study). The Compass Lexecon Study was introduced at the hearing as Public Staff Lucas Redirect Exhibit 3. Witness Lucas testified that the Compass Lexecon Study, and in particular Exhibit 1 to the Study, showed that beginning in 2012, assuming the merger was approved, the utilization of DEC's large coal-fired generating units would increase across the majority of months, while the utilization of DEP's large coal-fired generating units would decrease across the majority of months. Witness Lucas stated that the Study further found that during hours when DEC's high efficiency coal-fired generators have excess production capability they can provide lower cost energy compared to DEP's somewhat less efficient large coal-fired generators, such as Roxboro and Mayo.

In his supplemental testimony, witness Lucas noted that Ordering Paragraph No. 3 in the Commission's Merger Order issued on June 29, 2012, approved the JDA and that the Merger Order was issued more than one month before the effective date of the 2012 Agreement, August 1, 2012. Tr. Vol. 3, 26. Further, the Commission notes that on July 2, 2012, Duke Energy and Progress Energy filed a letter in the merger proceeding notifying the Commission that they accepted all of the terms and conditions of the Merger Order.

In their supplemental rebuttal testimony, witnesses Coppola and Halm asserted that negotiations regarding the 2012 Agreement commenced in June 2011, well before there was any degree of certainty regarding the outcome of the merger and before important aspects of the JDA were solidified. They further testified that the parties had largely resolved the major commercial terms of the 2012 Agreement by February 2012, well before there would have been certainty regarding the merger or the ultimate impact of the JDA. Tr. Vol. 3, 184. Further, witnesses Coppola and Halm stated that they had been advised that it was not possible to have finalized the JDA prior to the Commission's approval of the merger. They stated that DEP merger witness Weintraub stated in his initial testimony in the merger proceeding that DEC and DEP could not share proprietary information prior to approval of the merger. They also asserted that while the Compass Lexecon Study projected total savings from the JDA over a five-year period, it also described the complexity of the JDA and that many issues other than fuel costs had to be considered. Witnesses Coppola and Halm testified that many of these issues could not be resolved until the merger was approved and proprietary information could be shared and analyzed. Tr. Vol. 3, 184-185.

Finally, witnesses Coppola and Halm testified that the JDA did not reduce the amount of generation at Mayo and Roxboro; rather, the primary cause of the reduced generation was lower gas prices. They noted that during the Business Court trial DEP witness Eric Grant testified that the JDA had not caused the reduction in dispatch from Roxboro and Mayo, that Grant testified that 80% of the megawatt hours had flowed from DEP to DEC under the JDA, and that the court rejected the position that the JDA caused a reduction in DEP's production of synthetic gypsum. *Id.* at 186.

Public Staff witness Lucas testified as to what the Company's 2010 and 2012 avoided cost data showed regarding DEP's planned dispatch of coal-fired units. He testified that in DEP's responses to data requests in the 2010 and 2012 Avoided Cost proceedings, the latter being more than two months before DEP signed the 2012 Agreement on August 1, 2012,[1] DEP stated that it anticipated that dispatch of its coal plants would play a lesser role going forward in meeting energy requirements. According to witness Lucas, this evidences that DEP knew that less frequent dispatch of its coal plants would mean reduced gypsum production, and that DEP should have taken that information into account when negotiating and signing the 2012 Agreement. *Id.* at 22-23.

Further, Public Staff witness Lucas testified in detail about DEP's and DEC's extensive pre-2011 efforts at converting from generating electricity with coal to generating with natural gas. Witness Lucas opined that this evidence shows that well before negotiating and executing the 2012 Agreement DEP was aware that it was retiring coal-fired units and replacing them with natural gas-fired generation. Tr. Vol. 3, 28-29.

Public Staff witness Lucas also testified regarding DEP's gypsum forecasts. He stated that in a forecast performed on December 15, 2011, attached to his testimony as Lucas Supplemental Exhibit 4, DEP was not forecasting production of more than 50,000 dry tons of gypsum per month from Roxboro and Mayo for any month in 2012. Witness Lucas also attached to his testimony Lucas Supplemental Exhibit 5, which was a gypsum forecast that DEP provided to CTG on May 23, 2012, more than two months before DEP executed the 2012 Agreement. According to witness Lucas, the document shows that as of May 2012 DEP was not forecasting 50,000 tons of gypsum a month from Roxboro and May through the end of 2013. *Id.* at 29.

In addition to the gypsum forecasts, witness Lucas provided evidence of the actual production of gypsum at Roxboro and Mayo leading up to the execution of the 2012 Agreement. Attached to his testimony as Lucas Supplemental Exhibit 1 was a table which showed that for 2008, 2009, 2010, and 2011, the highest annual production at both plants combined averaged 37,748 wet tons per month (2010), which he testified equates to about 35,280 dry tons per month. According to witness Lucas, in 2012 the two plants averaged 51,023 wet tons per month, which equates to 47,686 dry tons per month at a 93.46% wet-to-dry reduction. Witness Lucas asserted that the gypsum forecasts and actual production history demonstrate that in 2012 DEP knew or should have known that it was not producing and was not expected to produce 50,000 net dry tons of gypsum a month at Roxboro and Mayo. *Id.* at 29-30.

During the hearing, witness Lucas testified that DEP overcommitted in the 2012 Agreement. He asserted that DEP had plenty of information on hand to cause it to realize that it was not going to be able to meet the 50,000-ton MMQ. According to witness Lucas, this included the fact that in the three years prior to 2012 the Roxboro and Mayo Plants had not come close to making 50,000 tons of gypsum per month, and that in the 2010 avoided cost proceeding DEP predicted that coal-fired plants would be dispatched less frequently going forward. Witness Lucas further cited DEP's 2010 prediction that its 2011 coal dispatch would be about 92% less than in

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[1] According to witness Lucas, presumably DEP ran the models that produced these numbers well in advance of filing its 2012 Avoided Cost data.

2010, and its prediction of reduced dispatch until about 2017, when coal dispatch would go down to 63% of DEP's 2010 level. Witness Lucas also testified that around 2009 natural gas prices had plummeted, and that they were still low in 2012. He stated that DEP had two natural gas-fired high efficiency plants under construction at the time that could have displaced Roxboro and Mayo's generation. Tr. Vol. 3, 22, 45-46.

Witness Lucas further asserted that DEP had every reason to believe it could never meet the 50,000 tons, and every reason to at least examine the option of not committing itself to supply 50,000 tons of gypsum to CTG per month. He testified that he did not know if DEP would have ended up in the same place had they accepted CTG's proposed revisions, but that it would have been less likely. *Id.* at 70-71. Witness Lucas testified that he had not performed any analysis or examination to determine whether or not DEP would have been able to avoid a breach of the provisions of the CTG Redline had it accepted those provisions and reduced them to a final executed agreement. Tr. Vol. 3, 131-135.

Company witnesses Coppola and Halm acknowledged in their supplemental rebuttal testimony that generation from DEP's coal-fired plants was generally declining over the period 2010-2012. They also acknowledged that the Company was retiring some of its smaller, less efficient coal-generating units during that time frame. They asserted, however, that it is a leap of tremendous proportion to conclude from these facts that the Company had sufficient information to definitively conclude that it would be unable to satisfy its gypsum supply obligation over a 17-year period. They contended that it was not accurate to assume that gypsum production bears a linear relationship to capacity factors, and there are many factors that influence actual gypsum production. They stated that coal with a 3% sulfur content (e.g. Illinois Basin coal) will produce three times as much gypsum as 1% sulfur content (e.g. Central Appalachian coal) for the same volume of coal burn with similar heat content. Similarly, they testified that limestone purity and sulfur dioxide (SO2) removal efficiency can have a material impact on the amount of synthetic gypsum produced from a coal-fired unit independent of the unit's capacity factor. They stated that during the time period in which the parties were negotiating the 2012 Agreement DEP was performing testing of various combinations of Illinois Basin coal at Roxboro and Mayo and that use of that lower cost, higher sulfur coal would, all things being equal, increase the amount of gypsum being produced even at a reduced level of generation. Tr. Vol 3, 182-183.

With respect to the Company's gypsum forecasts presented by witness Lucas, while agreeing that the two forecasts projected gypsum production levels lower than the Fixed MMQ over a short-term period, witnesses Coppola and Halm stated that two factors should be taken into account. First, during the 2011-2012 time period, the gypsum stockpile was near the maximum capacity and therefore, there was no scenario where DEP would be deemed to have failed to provide the MMQ in the short term, even if the actual gypsum production from Roxboro and Mayo was less than 50,000 tons per month. Therefore, they asserted that the fact that the short-term forecasts show monthly production less than 50,000 tons does not mean that DEP did not have confidence in its ability to satisfy the Fixed MMQ in the short term. Second, according to witnesses Halm and Coppola the issue is not whether DEP would have been able to satisfy its delivery obligation over a single year, but whether it could satisfy its obligation over the entire term of the 2012 Agreement. Id. at 187-188.

DISCUSSION AND CONCLUSIONS

Legal Standard

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.

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.

Order Granting Partial Increase in Rates and Charges, *Application by Carolina Power & Light Company for Authority to Adjust and Increase Its Rates and Charges*, No. E-2, Sub 537, at 14 (N.C.U.C. Aug. 5, 1988), *rev'd in part on other grounds and remanded, Utils. Comm'n v. Thornburg*, 325 N.C. 484, 385 S.E.2d 463 (1989) (Harris Order).

In the Harris Order the Commission stated that challenging prudence requires a detailed and fact intensive analysis, and the challenger is required to (1) identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives; and (3) quantify the effects of the imprudence on ratepayers. Harris Order, at 252.

As a general rule, if the utility presents evidence supporting the reasonableness and prudence of an act and no evidence challenging the reasonableness or prudence is presented, then a prima facie case is made as to reasonableness and prudence. *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 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. In the Interim Order the Commission concluded that all of these facts were known to DEP when it entered into the 2012 Agreement with CTG on August 1, 2012. Nevertheless, DEP negotiated and signed the 2012 Agreement that committed it to deliver 50,000 tons of gypsum per month from the Roxboro Plants through April 2029, and to maintain a gypsum stockpile of 250,000 tons for that same period of time. The Commission concluded that the evidence presented by Public Staff witness Lucas regarding the JDA, natural gas prices, and DEP's and DEC's conversion from coal-fired generation to natural gas-fired generation was substantial evidence that rebutted DEP's *prima facie* case of the prudence and reasonableness of its decisions and actions in connection with the 2012 Agreement. As a result, the burden of proof on this issue remained with DEP.

With respect to whether DEP acted prudently in entering into the 2012 Agreement, witness Lucas stated that

> The Public Staff concludes that it was unreasonable and imprudent for DEP to enter into the 2012 Agreement as it was written, especially when, as was concluded in the lawsuit, DEP was offered the opportunity to enter into a more flexible arrangement. Therefore, at least some of the costs arising out of the lawsuit with CertainTeed should be excluded from recovery.

Tr. Vol. 3, 30

On the other hand, the DEP Panel concluded that DEP's actions were reasonable and prudent. Tr. Vol. 3, 164.

Specific and Discrete Instances of Imprudence

The Commission finds and concludes that at the time that the 2012 Agreement was being negotiated by DEP and CTG, and before it was signed in August 2012, DEP's management knew, or reasonably should have known, that the effect of the merger, and specifically the JDA, was projected to result in the increased dispatch of the more efficient DEC coal units and the decreased dispatch of the DEP coal units, including Roxboro and Mayo. In connection with this finding the Commission gives substantial weight to the Compass Lexecon Study, and in particular Exhibit 1 to the Study showing that beginning with 2012 the utilization of DEC's large coal-fired generating units would increase across the majority of months, while the utilization of DEP's large coal-fired generating units would decrease across the majority of months. The Commission further notes that the Study was filed as Exhibit 4 of the merger application as a public document. Obviously, witness Coppola had access to the Study. Further, Company management was obviously aware of the Study.

The Commission further finds and concludes that at the time the 2012 Agreement was being negotiated by DEP and CTG, and before it was signed in August 2012, DEP was engaged in a steady transition from the use of coal-fired generation to the use of natural gas-fired generation, including the retirement of coal-fired plants as soon as gas-fired CCs came online to replace the coal plants. The Commission gives substantial weight to Public Staff witness Lucas's testimony on this point. The Commission also notes that the DEP witnesses presented no substantial evidence to refute this point.

In addition, the Commission gives significant weight to witness Lucas' testimony about the drop in natural gas prices that began around 2009 and was continuing, or at a minimum was sustained, through August 2012. The DEP Panel testified that, "Specifically, due to the decrease in natural gas prices, the dispatch of Roxboro and Mayo Generating Stations decreased and therefore the amount of synthetic gypsum produced decreased." Tr. Vol. 2, 146. Yet, they provided no testimony about how, or whether, the sustained decrease in natural gas prices from around 2009 to August 2012 was used by them in assessing whether DEP could meet the Fixed MMQ under the 2012 Agreement.

Based on the evidence concerning natural gas prices, the potential effects of the JDA, and DEP's conversion to natural gas-fired generation, the Commission concludes that DEP should have been cautious in assessing whether these developments would reduce its coal-fired generation substantially; and, consequently, could result in DEP's failing to meet the Fixed MMQ for the 17-year term of the 2012 Agreement. That level of cautiousness is not apparent from the evidence presented by DEP regarding its negotiations with CTG. In particular, the evidence tends to show that after DEP received the Roxboro Scenarios and the CTG Redline it did not engage in significant negotiations with CTG around the possibility of additional flexibility in its supply obligation and CTG's acceptance obligation. According to Engelhardt, DEP's response to the CTG Redline was essentially that it did not want to negotiate further because it was satisfied with the quantity terms of the 2008. Lucas Exhibit 4, pp. 157-59

In addition, in response to questions from the Commission about why DEP rejected CTG's offer to set the stockpile minimum at 100,000 tons, witness Coppola stated

> Yeah. So there certainly was a potential for the 100,000-ton stockpile to be a requirement with damages. It's hard to say because we didn't get down to that level of granularity in the negotiations because we took a different path, the path that we finally ended up with in the 2012 Agreement[.]

Tr. Vol. 3, 212.

As the Commission has previously concluded, CTG was not reasonably likely to give up the supply certainty established in the 2004 and 2008 Agreements, even though the Roxboro Scenarios and the CTG Redline suggest that CTG may have been willing to consider some flexibility with respect to month-to-month quantities delivered. Nevertheless, the Commission would have found it instructive to have some evidence from DEP as to why DEP did not explore the possibility of more flexibility in meeting its obligation. CTG initiated negotiations for a revision of the 2008 Agreement with proposals that signaled possible receptiveness to some degree of flexibility, but DEP offered the Commission no explanation whatsoever as to why it declined to explore the extent of CTG's possible openness to flexibility. The only substantive change resulting from the negotiations was DEP's agreement to establish a minimum stockpile obligation of 250,000 tons, an obligation that did not exist in the 2008 Agreement. This result leaves the Commission wondering what DEP received and CTG gave up, if anything, in return for this new minimum stockpile obligation on DEP.

Further, in both the Business Court and before the Commission DEP witness Coppola testified that the intent of DEP and CTG was to negotiate and enter into a variable supply contract. Tr. Vol. 2, 165-66; Judgment, Finding of Fact No. 107. As the Business Court concluded, the 2012 Agreement was ambiguous on that point, leading the court to take extensive testimony on the intent of the parties and ultimately to conclude that the 2012 Agreement was intended by DEP and CTG to be a fixed supply contract requiring DEP to deliver 50,000 tons per month. *Id.*, Finding of Fact Nos. 120-131. It would not appear difficult for DEP to have drafted language that unambiguously stated the parties' intent that DEP would deliver and CTG would accept the amount of gypsum produced at the Roxboro Plants. The Commission expects DEP to exercise more care in drafting its contract language in the future.

With respect to whether the evidence of record in this proceeding demonstrates imprudence by DEP, the Commission concludes that DEP presented substantial evidence of its prudence and the Public Staff presented substantial evidence tending to show DEP's imprudence. Ordinarily, the Commission would continue its analysis by weighing the competing evidence and making a determination of prudence or imprudence from a preponderance of the evidence. In this instance that determination is made more difficult by the very sparse evidence concerning the parties' motives, objectives, or evaluation of possible options. However, ultimately, the Commission has found that it need not engage in the exercise since the dispositive elements are the second and third *Harris* criteria.

Existence of Prudent Alternatives

As previously discussed, the Roxboro Scenarios and CTG Redline were an invitation by CTG for the exploration of more flexibility in the contract between the parties. The Roxboro Scenarios included three concepts relating to gypsum supply and acceptance by the parties. . . From the four corners of the document setting out the scenarios it would appear that CTG was potentially willing to contemplate flexibility not only with respect to monthly delivery quantities but also, possibly, with respect to the annual minimum delivery requirement. The Commission is unable to conclude from this, however, that the Roxboro Scenarios document can carry the weight the Public Staff ascribes to it. There is no evidence that any significant negotiations were premised on the Roxboro Scenarios, and the Commission cannot engage in speculation about what would have happened during any hypothetical negotiations around the Roxboro Scenarios or whether those negotiations might have ultimately led to an executed agreement more favorable to DEP, one with quantity terms that could have been performed by DEP over an extended period without breach. Contract negotiations involving complex commercial agreements such as the one at hand in this case often take unexpected or unpredictable turns; the positions of parties change and morph as different competing considerations are weighed, and what starts out as a simple concept sheet may become in the end an elaborate document whose terms bear only a small resemblance to where the negotiations began.

The Roxboro Scenarios were followed almost immediately by Engelhardt providing to DEP the CTG Redline. That contract proposal can be read as a definite and firm offer for DEP's consideration, but it does not track the Roxboro Scenarios and, most importantly of all, it stipulates a minimum 600,000 annual ton delivery requirement. Whatever flexibility the CTG Redline may have offered DEP with respect to monthly quantities and stockpile levels, it did not offer the prospect of dropping the fixed minimum annual quantity. In some respects, the annual 600,000-ton gypsum supply obligation proposed by CTG in the CTG Redline might have been less burdensome than the 50,000-ton Fixed MMQ agreed to by DEP in the 2012 Agreement. If there is one certainty in the electric utility business it is that the generation levels of electric plants vary from month to month based on a myriad of factors, including weather, maintenance needs, and the availability of other generating plants. Thus, for example, it might have been helpful for DEP to have the flexibility of making up quantities of gypsum missed during the months of January and February due to a mild winter with quantities produced in July and August as the result of a hot summer. Standing alone, the choice of an annual requirement of 600,000 tons of gypsum versus a monthly requirement of 50,000 tons might be the reasonable choice.

However, as DEP maintained in its testimony the terms of the CTG Redline had to be considered by DEP in their entirety, not piecemeal. In particular, the DEP Panel testified that one reason DEP rejected the CTG Redline was that it "introduced new and potentially onerous provisions concerning DEP's obligation to maintain a minimum Stockpile." Tr. Vol. 3, 174. As an example of this, in its Post-Hearing Brief DEP discussed the lack of a defined monthly supply/acceptance amount in the CTG Redline, and contended, therefore, that the CTG Redline would enable CTG to take any amount of gypsum off of the stockpile at any time, thus potentially requiring DEP to replenish the stockpile on a regular basis. DEP also cited the Business Court Judgment as reaching this conclusion. DEP Brief, at 11-12.

In addition, the CTG Redline liquidated damages provisions offered nothing substantively different from the corresponding section of the 2012 Agreement. In the 2012 Agreement, the liquidated damages provision stated the following grounds for CTG's receipt of liquidated damages, in pertinent part:

> Discontinued Supply bv Progress Energy. If Progress Energy ...(b) takes any action that prevents or will prevent Progress Energy from supplying at least fifty percent (50%) of the Minimum Monthly Quantity each month over a five (5) year period, or (c) takes any other action that causes Progress Energy to supply 300,000 Net Dry Tons or less Gypsum Filter Cake per year in two (2) consecutive Contract Years [.]

In subsection (b), the CTG Redline struck the word "Monthly" and replaced it with "Annual." At first glance, this would appear to be an advantage, as instead of being liable for liquidated damages if DEP missed delivering 25,000 tons during just one month a year in five consecutive years under subsection (b) of the 2012 Agreement, under the CTG Redline DEP would only be liable for liquidated damages if it failed to supply 300,000 tons every year for five consecutive years. However, the CTG Redline also retained subsection (c), thus cancelling any advantage that subsection (b) may have provided. The confused drafting in this provision reinforces the need for caution in drawing any conclusion about whether or not the CTG Redline would have led to a final, executed agreement on terms more favorable to DEP than the 2012 Agreement itself.

Based on a consideration of all the evidence the Commission is unable to identify a specific alternative agreement that would have resulted from DEP's attempt to negotiate based on the Roxboro Scenarios or the CTG Redline <u>and that</u> would have contained final, executed terms more favorable to DEP than the 2012 Agreement. In particular, the Commission concludes from the evidence that there was no reasonable likelihood that any alternative agreement resulting from such negotiations would not have contained both (i) a 600,000 ton minimum annual quantity commitment, and (ii) a provision putting DEP in breach if it failed to deliver at least 50% of the minimum annual quantity, or at least 300,000 tons, for two consecutive years.[1]

Quantification of Alleged Imprudently Incurred Costs

Witness Lucas testified that on March 9, 2017, DEP sent CTG a letter notifying CTG that the gypsum stockpile would fall below the required minimum under the 2012 Agreement. He further testified that DEP failed to meet the 50,000 tons per month requirement in May and June 2017, and September 2017 through January 2018. Tr. Vol. 2, 64.

The DEP Panel testified that even if DEP had chosen to accept the terms of the CTG Redline it would have ended up defaulting and paying liquidated damages. Tr. Vol. 3, 247-48. Further, the DEP Panel testified as follows:

> Q How did the Company go about deciding whether or not to elect to discontinue supply under the Agreement at the time it did so?
>
> A We evaluated the long-term forecast, the short and long-term forecast, and it did not appear that we would be making enough material to satisfy the Agreement and that it would drop to substantially lower numbers, drop well below 50 percent of the obligation, and that we had reviewed what the cost would be associated with getting alternate material from other sources, we looked internally and externally, and found that material would not be available consistently enough and the price was - exceeded our other options that we had per, I believe, Section 6.2.

Tr. Vol. 3, 246. This is the substance of DEP's position that had it accepted the CTG Redline, which was the only definite offer made by CTG in the 2011-2012 negotiations, it still would have ended up in a position of breach, termination, and payment of liquidated damages. In evaluating this contention and applying the third Harris Order criterion the Commission thus has sought to consider what, if anything, would have happened differently in the time period 2018-2019 had DEP been subject to the quantity and delivery performance standards under the CTG Redline.

During the hearing, Public Staff witness Lucas was asked questions by the Commission about whether DEP would have defaulted on the contract if DEP had accepted the terms of the CTG Redline, in particular the 100,000-ton stockpile minimum, rather than the 250,000-ton minimum agreed upon in the 2012 Agreement. Witness Lucas testified that the Public Staff had not performed an assessment of whether DEP would have defaulted under the terms of the CTG

[1] During the hearing the Commission explored whether DEP had options available to it in 2011 other than negotiating a modified agreement and continuing performance under such modified agreement, including options such as attempting to identify potential breaches of the 2008 Agreement by CTG to use either as grounds for terminating the 2008 Agreement entirely or as leverage in negotiating a more favorable new agreement. The DEP Panel testified that DEP had explored such options but had concluded that it did not have grounds to declare CTG in default or in breach of the 2008 Agreement. Tr. Vol. 3, 200-202. The Public Staff witnesses did not dispute this testimony.

Redline. Tr. Vol. 3, 131-135. This lack of analysis by the Public Staff places the Commission in a position of uncertainty and speculation as to whether ratepayers would have been better off if DEP had decided to accept the terms of the CTG Redline. The Commission must make its decisions based on substantial evidence, not on speculation.

In consequence of the Public Staff's failure to analyze the likely outcome of DEP performance under the CTG Redline and in order to probe the DEP Panel's contention concerning that outcome on May 28, 2020, the Commission entered its Order Requiring Filing of Post-Hearing Exhibit, that exhibit being an affidavit that had been filed by witness Halm in the Business Court (Halm Affidavit). Mr. Halm referred to that affidavit in his testimony before the Commission in response to questions about whether DEP would have been able successfully to maintain performance under the CTG Redline. The Halm Affidavit, dated February 28, 2018, tends to support DEP's position that it would have ended up being in breach of the either the CTG Redline or the 2012 Agreement in the long-term. In summary, the Affidavit showed that DEP was steadily losing ground in its effort to supply at least 300,000 tons of gypsum per year, the trigger level, if sustained for two consecutive years, for a potential default and breach by DEP of the 2012 Agreement. The Halm Affidavit showed that during 2017 CTG accepted an average of 37,679 tons of gypsum per month, and that DEP was able to meet this demand and maintain the stockpile at the required 250,000 tons by bringing 20,000 tons of gypsum from DEC's Belews Creek plant from July 2017 through January 2018. In addition, the affidavit stated

> DEP forecasts that its Roxboro and Mayo Plants will produce 57,565 net dry tons of Gypsum Filter Cake between March 2018 through June 2018, a total of 213,365 net dry tons of Gypsum Filter Cake in 2018, and a total of 241,099 net dry tons of Gypsum Filter Cake in 2019.

Halm Affidavit, at 6.

DEP's forecast of 2018 and 2019 gypsum production from the two plants, if considered alone and if actually achieved, would have fallen short of both the 600,000 ton annual commitment contained in the 2012 Agreement and in the CTG Redline and, more importantly, the 300,000 ton annual threshold for triggering potential default and remedies under both the 2012 Agreement and the CTG Redline.

The Commission must, however, also consider the availability of gypsum previously produced by DEP and stockpiled under the agreement. The analysis here is different with respect to the 2012 Agreement and the CTG Redline. Under the 2012 Agreement DEP was to keep the minimum stockpile level at no less than 250,000 tons. The Halm Affidavit establishes that after March, 2017, and for the remainder of 2017 the stockpile (above grade and base quantities combined) never exceeded 206,000 tons and that in June, 2017, it fell as low as approximately 121,000 tons. At the beginning of 2018, the stockpile (combined amounts) stood at approximately 158,000 tons. While this amount could have been drawn upon during 2018 and 2019 to supplement production of gypsum from the two plants, and thereby enable DEP's deliveries to remain above, but only just barely above, the 300,000 ton annual triggering point, drawing down the stockpile for that purpose would only have put DEP further in violation of its obligation to maintain a minimum stockpile of 250,000 tons.

Under the proffered CTG Redline the minimum stockpile level was reduced to 100,000 tons. The Halm Affidavit indicates that at all times during 2017 and at the beginning of 2018 the below grade, or "base," stockpile contained an estimated 120,842 net dry tons. While this amount, considered in isolation, would have been sufficient to satisfy DEP's 100,000 ton minimum stockpile obligation, it would have left very little above ground quantities available for DEP to use to supplement production from the two generating plants. In January, 2018, the above ground portion of the stockpile contained only 37,391 dry tons. This was manifestly inadequate to enable DEP to maintain a minimum annual delivery of 300,000 tons during 2018 and 2019, assuming its production forecast proved accurate. Moreover, as already noted, even if DEP had exhausted the entire stockpile available to it as of January 2018, it would only barely have been able to deliver 300,000 tons to CTG in 2018 and again in 2019. Based on the Halm Affidavit it thus appears that the more favorable terms of the CTG Redline with respect to the minimum required stockpile level would, at the very best, have bought DEP only a few months more time before it would have faced the same situation of potential default and breach that faced it in 2018. With respect to the third Harris Order criterion the Commission concludes from the preponderance of the evidence that even if DEP had accepted the CTG Redline exactly as it was tendered, DEP would have been unable to perform for the remaining term of the agreement and would, by some time likely in 2018 or 2019, have been facing the same choice whether to continue under the agreement or to terminate and pay liquidated damages that confronted it after the Business Court rendered its judgment.

Based on the evidence in the record, the Commission finds and concludes that by 2018 or 2019 DEP would have been in the same position under the terms of the CTG Redline as it was under the terms of the 2012 Agreement. As a result, DEP's rejection of the terms of the CTG Redline does not result in a quantifiable difference to ratepayers.

Because the Commission has concluded that neither the second nor the third criteria in the Harris Order are satisfied on this record, DEP's request for recovery in its fuel rider of the amount of damages awarded by the Business Court and the liquidated damages paid to CTG are not subject to disallowance on grounds of imprudence, even if the Commission were to find that DEP's failure to negotiate for more flexibility in the supply terms of the 2012 Agreement was imprudent.

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

The evidence supporting these findings of fact and conclusions is contained in the direct and supplemental testimony of Public Staff witness Lucas, the pre-filed direct testimony of Company witness Dana Harrington, the rebuttal and supplemental rebuttal testimony of Company witnesses Coppola and Halm, and the Business Court Judgment.

On August 28, 2018, the Business Court ruled in CTG's favor, and ordered DEP to pay $1,084,216 to reimburse CTG for the cost of transportation that DEP had charged CTG for bringing replenishment gypsum from Belews Creek from July 2017 through January 2018, and to provide a replenishment plan for meeting the 2012 Agreement's supply requirements within 90 days. Judgment, at 77-82.

Witness Lucas testified that DEP and CTG reached a settlement on October 1, 2018, in which DEP agreed to pay liquidated damages in return for being released from its remaining obligations under the 2012 Agreement, except for a commitment to deliver a minimum amount of gypsum for approximately two years. Tr. Vol. 2, 65-68. The settlement was introduced into evidence as Confidential FPWC Harrington Cross-Exam Exhibit 4.

In prefiled direct testimony, DEP witness Dana Harrington testified regarding the Company's proposed adjustment relating to liquidated damages being paid over a ten-year period by DEP. Witness Harrington testified that DEP was requesting that the North Carolina retail portion of the liquidated damages be recovered from ratepayers over the next ten years, and that DEP had reflected this amount in its fuel cost application in this docket by: (1) a $6.6 million addition to the proposed Experience Modification Factor (EMF), and (2) a $5 million addition to DEP's proposed prospective fuel rates for December 2019 through November 2020. Tr. Vol. 1, 96-97. The DEP Panel testified that the Company ultimately determined that discontinuing supply under the 2012 Agreement and paying liquidated damages was the most prudent option for customers. Tr. Vol. 3, 165-66. Public Staff witness Lucas agreed. *Id.* at 21. In addition, the DEP Panel testified that CTG is today continuing to accept gypsum from DEP pursuant to an Interim Supply Agreement. Tr. Vol. 2, 194-96; Confidential FPWC Harrington Cross-Exam Exhibit 4.

In its Post-Hearing Brief DEP explained that the contract damages ordered in the Judgment, $1,010,938.20, was a reimbursement to CTG of the transportation costs for gypsum transported by DEP from Belews Creek to replenish the stockpile, as noted above in the DEP Panel's testimony. These transportation costs were paid by CTG under protest, subject to resolution in the court case. DEP stated that the North Carolina portion of the transportation costs requested for recovery in this case is $619,225.99. DEP Brief, at 34.

DISCUSSION AND CONCLUSIONS

Based on a preponderance of the evidence, the Commission finds and concludes that it is reasonably likely that DEP would have incurred the transportation costs of bringing replenishment gypsum from Belews Creek to Roxboro even if DEP had chosen to accept the terms of the CTG Redline. Therefore, DEP should be allowed to recover the North Carolina portion of the transportation costs from its ratepayers.

Further, the Commission finds and concludes that after entry of the Business Court Judgment it was reasonable and prudent for DEP to pay the contract damages ordered by the court and to terminate the 2012 Agreement and pay liquidated damages to CTG. As a result, DEP should be allowed to recover in its fuel costs the North Carolina allocable portion of the liquidated damages being amortized over a ten-year period, as testified to by DEP witness Harrington.

IT IS, THEREFORE, ORDERED as follows:

1. That DEP's request to recover the liquidated damages paid and remaining owing to CTG from ratepayers shall be, and is hereby, approved;

2. That DEP shall be, and is hereby, allowed to recover the North Carolina portion of its gypsum transportation costs, $619,225.19, from ratepayers; and

3. That DEP shall add the North Carolina allocable portion of the liquidated damages being amortized over a ten-year period and the gypsum transportation costs of $619,225.19 to its Experience Modification Factor in its 2020 fuel adjustment proceeding presently pending in Docket No. E-2, Sub 1250.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of July, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

DOCKET NO. E-2, SUB 1251

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 North Carolina General Statute § 62-133.8 and Commission Rule R8-67	))))))	ORDER APPROVING REPS AND REPS EMF RIDERS AND 2019 REPS COMPLIANCE REPORT

HEARD: Tuesday, September 15, 2020, at 10 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina (Public Witness Hearing, Hearing Examiner Heather Fennell, Presiding)

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

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

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For Carolina Utility Customers Association, Inc.:

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For Carolina Industrial Group for Fair Utility Rates II:

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

For North Carolina Sustainable Energy Association:

Peter H. Ledford, General Counsel, 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:

Gina C. Holt, Staff Attorney and Nadia L. Luhr, Staff Attorney,
Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On June 9, 2020, Duke Energy Progress, LLC (DEP or the Company), filed its 2019 REPS Compliance Report and application seeking an adjustment to its North Carolina retail rates and charges pursuant to N.C. Gen. Stat. § 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 Renewable Energy and Energy Efficiency Portfolio Standard (REPS), N.C.G.S. §§ 62-133.8(b), (d), (e) and (f) and to true up any underrecovery or overrecovery of compliance costs. DEP's application was accompanied by the testimony and exhibits of Megan W. Jennings, Renewable Compliance Manager and Veronica I. Williams, Rates and Regulatory Strategy Manager. In its application and prefiled testimony, DEP sought approval of its proposed REPS Rider, which incorporated the Company's proposed adjustments to its North Carolina retail rates.

On June 29, 2020, 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 DEP rebuttal testimony; required the provision of appropriate public notice; and mandated compliance with certain discovery guidelines.

The North Carolina Sustainable Energy Association, the Carolina Industrial Group for Fair Utility Rates II, 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 August 7, 2020, the Commission issued an Order Scheduling Remote Hearings for Expert Witness Testimony due to the COVID-19 pandemic. All parties subsequently filed their consent to a remote hearing.

On August 25, 2020, the Public Staff filed the affidavit of June Chiu, Staff Accountant in the Accounting Division, and the testimony of Jay B. Lucas, Manager, Electric Section – Operations and Planning in the Energy Division.

On September 4, 2020, DEP and the Public Staff filed a joint motion to excuse all witnesses from the evidentiary hearing. On September 11, 2020, the Commission issued an Order granting the joint motion; cancelling the expert witness hearing; receiving into evidence all prefiled testimony, affidavits, and exhibits from the DEP and Public Staff witnesses; and directing that proposed orders be filed by October 16, 2020.

On September 14, 2020, DEP filed the required affidavits of publication for the public notice in accordance with the Commission's June 29, 2020 Order.

The public witness hearing was held on September 15, 2020. No witnesses appeared.

On October 16, 2020, DEP and the Public Staff filed a joint proposed order.

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 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 2019, the Company must generally supply an amount of 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 2019, 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 other North Carolina electric suppliers, 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 statewide North Carolina retail sales. In its December 16, 2019 Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief, and its February 13, 2020 Errata Order, (2019 Delay Orders), issued in Docket No. E-100, Sub 113, the Commission modified the 2019 swine waste set-aside requirement for DEP, Duke Energy Carolinas, LLC (DEC) and Dominion Energy North Carolina to 0.04% of prior year North Carolina retail sales, and delayed for one year the scheduled increases to the requirement. In addition, the 2019 Delay Orders modified the 2019 statewide poultry waste set-aside requirement to 500,000 MWh, and delayed the subsequent scheduled increases by one year.

4. DEP complied with the 2019 solar set-aside requirement by submitting for retirement 77,375 renewable energy certificates (RECs) procured or generated from solar electric facilities and metered solar thermal energy facilities. DEP also complied with the 2019 poultry waste set-aside requirement by submitting for retirement 134,105 poultry waste RECs and 2,822 Senate Bill 886 RECs (SB 886 RECs), which are credited as 5,644 poultry waste RECs, for a total of 139,749 poultry waste RECs. The Company complied with the 2019 swine waste set-aside requirement by submitting for retirement 15,475 swine waste RECs. Finally, DEP submitted for retirement 3,636,128 general requirement RECs, representing the Company's total 2019 compliance requirement net of the set-aside requirements detailed above.

5. DEP met its total 2019 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. The Company is positioned to comply with its poultry waste set-aside requirement for compliance year 2020. Compliance beyond 2020 is dependent on the performance of current poultry waste-to-energy contracts, including two that are expected to ramp up production over the next few years.

7. DEP's ability to comply with the 2020 swine waste set-aside requirement is uncertain, as current contracts have not been able to deliver expected production, and new contracts have not come online nor delivered expected production in the timeframes originally planned.

8. DEP's REC inventory available for future use properly includes RECs generated from net metering customers receiving electric service under schedules other than time-of-use schedules with demand rates (NMNTD customers).

9. 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 12-month period beginning April 1, 2019 and ending March 31, 2020 (Test Period). The billing period for this proceeding is the 12-month period beginning December 1, 2020, and ending November 30, 2021 (Billing Period).

10. 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 will be approved for this proceeding.

11. The research activities funded by DEP during the Test Period are recoverable under N.C.G.S. § 62-133.8(h)(1)(b) and are within the $1 million annual limit established by the statute.

12. No costs associated with the implementation of DEP's Competitive Procurement of Renewable Energy (CPRE) Program are included for recovery in this REPS proceeding. DEP's costs associated with procurement of CPRE renewable energy resources and for the implementation of the Company's CPRE Program were submitted for recovery in its pending CPRE rider in Docket No. E-2, Sub 1254.

13. Section 62-133.8(h) authorizes electric power suppliers 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 G.S. 62-133.9." The term "avoided costs" includes both avoided energy costs and avoided capacity costs.

14. Under Commission Rule R8-67(e)(2), the total costs reasonably and prudently incurred during the Test Period to purchase unbundled RECs constitute incremental costs. The projected costs to purchase such RECs during the Billing Period constitute forecasted incremental costs.

15. DEP appropriately calculated its avoided costs and incremental REPS compliance costs for the Test Period and Billing Period.

16. For purposes of establishing the REPS experience modification factor (EMF) rider in this proceeding, the Company's incremental REPS compliance costs for the Test Period were $39,775,219, and these costs were reasonably and prudently incurred. The Company's projected incremental costs for the Billing Period are $39,413,260. DEP's Test Period REPS expense undercollection was $55,386 for the residential class. DEP's overcollections, including interest, were $(1,748,915) for the general service class and $(139,328) 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 $(48,478) for residential, $(43,376) for general service, and $(2,646) for industrial. Including credits for contract-related receipts, the net Test Period cost was $6,908 for the residential class, and net Test Period credits were $(1,792,291) for the general service class and $(141,974) for the industrial class. All amounts exclude the North Carolina regulatory fee (regulatory fee).

17. DEP's North Carolina prospective Billing Period expenses for use in this proceeding are $19,596,968, $18,656,884, and $1,159,408, for the residential, general service, and industrial classes, respectively, excluding the regulatory fee.

18. The appropriate monthly REPS EMF riders, excluding the regulatory fee, to be (credited to) or charged to customer accounts during the upcoming Billing Period are $0.00 for residential accounts, $(0.74) for general service accounts, and $(6.67) for industrial accounts.

19. The appropriate prospective REPS riders per customer account, excluding the regulatory fee, to be collected during the Billing Period are $1.29 for residential accounts, $7.71 for general service accounts, and $54.49 for industrial accounts.

20. 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 $1.29 for residential accounts, $6.97 for general service accounts, and $47.82 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 $1.29 for residential accounts, $6.98 for general service accounts, and $47.88 for industrial accounts.

21. DEP's REPS incremental cost rider, including the regulatory fee, to be charged to each customer account for the 12-month Billing Period is within the annual cost cap established for each class in N.C.G.S. § 62-133.8(h)(4).

22. As approved or modified by the Commission, the REC sales price calculation proposed by DEC and the Public Staff in DEC's REPS rider proceeding in Docket No. E-7, Sub 1229, shall also be applicable to any animal waste REC sales made by DEP to other electric power suppliers. Continued annual review of the calculation is appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

The evidence supporting these findings of fact appears in DEP's 2019 REPS Compliance Report, in the direct testimony and exhibits of DEP witnesses Jennings and Williams, in the testimony of Public Staff witness Lucas, and in the affidavit of Public Staff witness Chiu. 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 from a new renewable energy facility; (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 2019, DEP was required to 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 2019 is 0.20%.

Sections §§ 62-133.8(e) and (f) require DEP and the other North Carolina electric suppliers, 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 2019 Delay Orders, the Commission modified the 2019 swine waste set-aside requirement to require only the electric public utilities to comply, set the requirement at 0.04% of North Carolina retail sales, and delayed for one year the scheduled increases in the requirement for all electric power suppliers. In addition, the 2019 Delay Orders also modified the 2019 statewide poultry waste set-aside requirement to 500,000 MWh and delayed by one year the scheduled increases in the requirement. (Jennings Direct at 6)

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-7

The evidence supporting these findings of fact appears in DEP's 2019 REPS Compliance Report, which was admitted into evidence as Jennings Exhibit No. 1, in the direct testimony and exhibits of DEP witness Jennings, and in the testimony of Public Staff witness Lucas. In addition, the Commission takes judicial notice of the information contained in NC-RETS.

Witness Jennings testified that the 2019 REPS Compliance Report provided the information required by Commission Rule R8-67(c) for the calendar year 2019. (Jennings Direct at 8)

Witness Jennings further testified that the Company submitted for retirement 3,863,083 RECs, which includes 2,822 SB 886 RECs, each of which counts for two poultry waste and one general REC, to meet its total compliance requirement of 3,868,727 RECs. Within this total, the Company submitted for retirement: 77,375 RECs to meet the solar set-aside requirement; 134,105 RECs, along with 2,822 SB 886 RECs (which count as 5,644 poultry waste set-aside RECs), to meet the poultry waste set-aside requirement of 139,749 RECs; and 15,475 RECs to meet the swine waste set-aside requirement. (Jennings Direct at 8)

Witness Jennings' testimony states that the Billing Period for this Application covers two separate compliance reporting periods with different requirements for each period. In 2020, the Company estimates that it will be required to submit for retirement 3,793,823 RECs to meet its total compliance requirement. Within this total, the Company expects to be required to retire the following: 75,877 solar RECs, 26,557 swine waste RECs, and 195,649 poultry waste RECs, to meet the requirements set out in N.C.G.S. §§ 62-133.8(d), (e), and (f), respectively. In 2021, the Company estimates that it will be required to submit for retirement 4,690,561 RECs to meet its total compliance requirement. Within this total, the Company expects to be required to retire the following: 75,049 solar RECs, 26,268 swine waste RECs, and 251,548 poultry waste RECs, to meet the requirements set out in N.C.G.S. §§ 62-133.8(d), (e), and (f), respectively. (Jennings Direct at 8)

Witness Jennings testified that DEP met its 2019 solar set-aside requirement by procuring and earning 77,375 solar RECs and that, pursuant to the NC-RETS Operating Procedures, the Company submitted these RECs for retirement by transferring these RECs from the NC-RETS Progress Energy Electric Power Supplier Account to the Progress Energy Compliance Sub-Account. (Jennings Direct at 14-15)

Witness Jennings testified that DEP met the modified 2019 poultry waste set-aside requirement of 139,749 RECs. Pursuant to NC-RETS Operating Procedures, the Company submitted for retirement 134,105 poultry RECs and 2,822 SB 886 RECs (which count as 5,644 poultry waste RECs). Accordingly, the equivalent of 139,749 RECs were submitted for retirement by transferring them from the NC-RETS Progress Energy Electric Power Supplier Account to the Progress Energy Compliance Sub-Account. (Jennings Direct at 15-16)

Witness Jennings testified that DEP met the modified 2019 swine waste set-aside requirement of 15,475 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. (Jennings Direct at 16-17)

Witness Jennings further testified that the Company complied with its general requirement for 2019 by submitting 3,636,128 RECs for retirement by transferring them from the NC-RETS Progress Energy Electric Power Supplier Account to the Progress Energy Compliance Sub-Account. (Jennings Direct at 9)

Witness Jennings testified that DEP is in position to comply with its 2020 poultry waste set-aside requirement, and that future-year compliance is dependent on the performance of energy developers on current contracts. Two such contracts are expected to ramp up production over the next few years. She testified that the Company is taking various steps to secure poultry waste-to-energy resources to meet its future requirements, including: continuing direct negotiations for additional supplies and executing contracts; working with developers to overcome technological, permitting, and operating risks, and amending existing contracts to reflect more realistic outcomes; exploring expansion of use of poultry waste resources to produce thermal, multi-fuel, or directed biogas RECs; and searching the broker market for out-of-state RECs. (Jennings Direct at 16-17)

Witness Jennings testified that the Company's compliance with the swine waste set-aside requirement is uncertain, as existing contracts have not been able to reach contracted levels of production, and new contracts have not come online in the timeframes originally planned and have taken longer than expected to ramp up production. She stated that the degree to which DEP will be able to meet its established near-term future compliance requirements is dependent on a new facility coming online as scheduled, and all facilities producing REC quantities at fully contracted levels. Witness Jennings further cited circumstances currently creating challenges for suppliers in meeting contracted swine waste REC production levels, including: local opposition to facility siting, lack of firm and reliable feedstock quantities that were anticipated to deliver contracted RECs, and the various negative effects of the COVID-19 pandemic further interrupting the availability of swine waste resources. 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, among other efforts: negotiations for in-state and out-of-state supplies; working extensively with potential suppliers to overcome production risks or amend contracts to accommodate changing circumstances, or both; and pursuing new biomass and biogas swine resource options. (Jennings Direct at 18-20)

Public Staff witness Lucas recommended that the Commission approve DEP's 2019 REPS Compliance Report. (Lucas Testimony at 3) Specifically, he testified that for 2019 compliance, DEP needed to pursue retirement of a sufficient number of eligible RECs and energy efficiency certificates (EECs) so that the total equaled 10% of its 2018 North Carolina retail electricity sales. Witness Lucas stated that DEP needed to pursue retirement of sufficient solar RECs to match 0.20% of its retail sales in 2018. In addition, he testified that the 2019 Delay Orders modified the requirements for swine and poultry energy established in N.C.G.S. §§ 62-133.8 (e) and (f), requiring retirement of a quantity of swine waste-derived RECs equal to 0.04% of DEP's 2018 retail sales, and retirement of an amount of poultry waste-derived RECs matching the pro-rata share of the 500,000 MWh (or the thermal equivalent) statewide requirement allocated to DEP. (Lucas Testimony at 2-3)

No party disputed that DEP had fully complied with the applicable REPS requirements or argued that DEP's 2019 REPS Compliance Report should not be approved.

Based on the evidence presented and the entire record herein, the Commission finds and concludes that DEP has fully complied with the REPS requirements for 2019, as modified by the Commission's 2019 Delay Orders, and that DEP's 2019 REPS Compliance Report should be approved. The Commission further concludes that the RECs and EECs in the related NC-RETS compliance sub-accounts should be permanently retired.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 8

The evidence supporting this finding of fact is found in the testimony of DEP witness Jennings. In addition, the Commission takes judicial notice of its November 19, 2019 Order

Approving REPS and REPS EMF Riders and 2018 REPS Compliance Report issued in Docket No. E-2, Sub 1205.

Witness Jennings 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. She further stated the Company performed site visits and complied with the other 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. (Jennings Direct at 10-12) No party to this proceeding contested this testimony.

Based on the foregoing and the entire record herein, the Commission finds and concludes that the RECs generated by the net metering facilities as described above are properly included in DEP's inventory of RECs available for future REPS compliance use.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 9

The evidence supporting this finding is procedural in nature, found in the testimony and exhibits of DEP witness Williams, the testimony of Public Staff witness Lucas, and the affidavit of Public Staff witness Chiu, 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 12-month period ending March 31 of each year. Company witness Williams testified that the Test Period or EMF period used for this proceeding was the 12 months beginning on April 1, 2019 and ending on March 31, 2020. (Williams Direct at 3) 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 further 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. (Williams Direct at 4-5) Witness Williams also testified that the Billing Period for the REPS rider requested in the Company's application is the 12 months beginning on December 1, 2020, and ending on November 30, 2021. (Williams Direct at 3) 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. (Williams Direct at 4-5) The Test Period and the Billing Period proposed by DEP were not challenged by any party.

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

The evidence for these findings of fact can be found in the testimony and exhibits of DEP witnesses Jennings and Williams, the testimony of Public Staff witness Lucas, and the affidavit of Public Staff witness Chiu.

Based on the foregoing and the entire record herein, the Commission concludes that, consistent with Commission Rule R8-67(e)(3), the Test Period for this proceeding is the 12 months beginning on April 1, 2019, and ending on March 31, 2020.

Witness Jennings sponsored Confidential Jennings Exhibit Nos. 2 and 3 to her testimony, wherein she identified the renewable energy and REC costs, as well as "Other Incremental," "Solar Rebate Program," and "Research" costs that the Company has incurred or projects to incur in association with REPS compliance. With respect to research costs, Confidential Williams Exhibit No. 1 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 Jennings provided testimony and exhibits on the results and status of various studies, the costs of which DEP is including for recovery as research in its incremental REPS cost for the Test Period. (Jennings Direct at 25-33)

In his testimony, witness Lucas discussed the research costs submitted by the Company and stated the costs were within the $1,000,000 maximum annual limit allowed, and met the definition of costs qualified to be incurred for research as defined by N.C.G.S. § 62-133.8(h)(1)(b). (Lucas Testimony at 4)

Witness Jennings describes in her 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 by agreed-upon liquidated damages paid by sellers for failure to meet contractual milestones, and amounts paid for administrative contractual amendments requested by sellers. (Jennings Direct at 21-22)

Witness Jennings also testified that, pursuant to N.C.G.S. § 62-155(f), DEP developed a Solar Rebate Program, and she discussed the processes in place to pay rebates, and the resulting effect on the payments made each year. (Jennings Direct at 22-23) She further testified that the incremental costs incurred to "provide incentives to customers, including program costs, incurred pursuant to N.C.G.S. § 62-155(f)" are allowed to be recovered under N.C.G.S. § 62-133.8(h). Therefore, DEP has included for recovery in this filing costs incurred during the EMF period, and projected to be incurred in the Billing Period, related to the implementation of the Solar Rebate Program. These costs include the annual amortization of incentives paid to customers and program administration costs, which include labor, information technology, and marketing costs. (Jennings Direct at 24)

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.

The Commission concludes based on the foregoing and the entire record herein that the research activities funded by DEP during the Test Period are renewable research 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 further concludes that the Company has complied with the prior Commission orders requiring filing results of such research studies. In addition, the Commission finds that the research information DEP provided is helpful. Therefore, the Commission finds 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 the 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 also concludes the costs identified as Other Incremental and Solar Rebate Program are properly recoverable in the REPS EMF and REPS riders calculated in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 12

The evidence for this finding of fact is found in the testimony of DEP witness Jennings and in the testimony of Public Staff witness Lucas.

In her direct testimony, witness Jennings describes how the CPRE Program will affect DEP's future compliance with its general requirement, and how the program is reflected in compliance planning. She states that because the Company will use the RECs acquired through the CPRE Program for REPS compliance, CPRE Program implementation costs could be recovered through the REPS rider. She also notes, however, that the Company has elected to recover reasonable and prudently incurred costs incurred to implement the CPRE Program through the CPRE rider in Docket No. E-2, Sub 1254, as contemplated under Commission Rule R8-71(j). (Jennings Direct at 13-14)

In his testimony, witness Lucas confirms DEP is not requesting recovery of CPRE Program costs in this current REPS proceeding. He states that he does not agree with the recovery of any CPRE costs in a REPS rider, but notes that it is difficult to definitively make such a conclusion before the Commission fully considers CPRE costs in CPRE Program rider filings or other proceedings. Witness Lucas further cites comments filed jointly by DEC and DEP in Docket No. E-100, Sub 150 (page 13) specifically addressing cost recovery of bundled CPRE Program RECs through the CPRE Program rider mechanism, and reflecting CPRE Program-generated RECs used for REPS compliance at zero cost in REPS proceedings. Witness Lucas confirmed the Public Staff's position that it is appropriate to recover CPRE Program implementation costs in a CPRE Program rider filing pursuant to Commission Rule R8-71(j). (Lucas Testimony at 5-6)

The Commission concludes that the matter of the inclusion of any CPRE Program implementation costs in the REPS rider is more appropriately considered in the current CPRE Program cost recovery proceeding currently in process in Docket No. E-2, Sub 1254.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-15

The evidence for these findings of fact is found in DEP's Application and in the testimony and exhibits of DEP witnesses Jennings and Williams, the testimony of Public Staff witness Lucas, and the affidavit of Public Staff witness Chiu.

Section § 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 Jennings. Witness Williams also described in detail the methods used by the Company to determine the appropriate avoided cost to apply to REPS compliance purchased power agreements and the Company's biogas purchases used to produce renewable energy at its generating stations. (Williams Direct at 5-6)

In her affidavit, witness Chiu described the Public Staff's investigation and review of the Company's filing, including its evaluation of DEP's per books incremental costs and revenues, as well as the annual revenue cap for REPS requirements, for the Test Period. (Chiu Affidavit at 2-3) Based on her review of costs submitted for recovery, witness Chiu recommended approval of DEP's proposed monthly and annual REPS EMF increment rider for the residential customer class, and DEP's proposed EMF decrement riders for the general service and industrial customer classes. (Chiu Affidavit at 3) In his testimony, witness Lucas stated that the Public Staff agreed with the EMF and REPS monthly riders requested by DEP in its application filed with the testimonies of Company witnesses Jennings and Williams on June 9, 2020. (Lucas Testimony at 11)

Based on the foregoing and the entire record herein, the Commission concludes that DEP's total incremental costs incurred during the Test Period are $39,775,219, and that DEP's estimated incremental costs for the Billing Period are $39,413,260.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-21

The evidence supporting these findings of fact appears in DEP's Application, in the testimony and exhibits of DEP witnesses Jennings and Williams, the testimony of Public Staff witness Lucas, and the affidavit of Public Staff witness Chiu.

Williams Exhibit No. 2, Page 2 shows an EMF Period undercollection of $55,386 for the residential class, and EMF overcollections including interest of $(1,748,915) for the general service class and \$(139,328) for the industrial class. Williams Exhibit No. 4 shows additional credits for contract receipts by customer class of \$(48,478) for residential, \$(43,376) for general service, and \$(2,646) for industrial. The EMF period undercollection net of contract-related credits is \$6,908 for the residential class. The total EMF period overcollections including interest and contract-related credits, by customer class, are \$(1,792,291) for general service and \$(141,974) for industrial. As reflected on Williams Exhibit No. 4, witness Williams calculated a monthly per-account REPS EMF amount (excluding the regulatory fee) of \$0.00 for residential accounts, and monthly per-account REPS EMF credits (excluding the regulatory fee) of \$(0.74) for general service accounts and \$(6.67) for industrial accounts. Also on Williams Exhibit No. 4, she calculated the projected REPS costs for the Billing Period of \$19,596,968 for the residential class, \$18,656,884 for the general service class, and \$1,159,408 for the industrial class. 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 \$1.29 for residential accounts, \$7.71 for general service accounts, and \$54.49 for industrial accounts. The combined monthly REPS and REPS EMF rider charges per customer account, excluding the regulatory fee, to be collected during the Billing Period are \$1.29 for residential accounts, \$6.97 for general service accounts, and \$47.82 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 \$1.29 for residential accounts, \$6.98 for general service accounts, and \$47.88 for industrial accounts. Witness Williams testified that the Company's REPS incremental cost rider to be charged to each customer account for the 12-month Billing Period is within the annual cost cap established for each customer class in N.C.G.S. § 62-133.8(h)(4). (Williams Direct at 10)

Public Staff witness Chiu stated in her affidavit that as a result of its investigation, the Public Staff is recommending annual REPS EMF increment or decrement riders of \$0.01, \$(8.89), and \$(80.08) per customer account for DEP's residential, general service, and industrial customers, respectively, excluding the North Carolina regulatory fee. Excluding the regulatory fee, the corresponding monthly REPS EMF increment or decrement rider amounts are \$0.00, \$(0.74), and \$(6.67) per customer account for DEP's residential, general service, and industrial customers, respectively. (Chiu Affidavit at 3)

Public Staff witness Lucas recommended that the Company's proposed prospective monthly REPS rider amounts per customer account, excluding the regulatory fee, of \$1.29 for residential accounts, \$7.71 for general service accounts, and \$54.49 for industrial accounts be approved. Combined with the monthly EMF rider amounts recommended by witness Chiu, witness Lucas recommended approval of the following total monthly REPS charge per customer account, excluding the regulatory fee: \$1.29 for residential accounts, \$6.97 for general service accounts, and \$47.82 for industrial accounts. (Lucas Testimony at 11)

The Commission concludes that DEP's calculations of its REPS and REPS EMF riders are reasonable and appropriate. Accordingly, the Commission finds 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 Williams Exhibit No. 4, are appropriate. Finally, the Commission 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).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 22

The evidence supporting this finding of fact appears in the testimony of Public Staff witness Lucas and the affidavit of Public Staff witness Chiu.

Witness Lucas testified that, over the past four years, DEC has sold set-aside RECs to other electric power suppliers to assist them with their REPS compliance. He further described the sales price calculation and noted the Public Staff's concern with an aspect of the method used to determine the sales prices. Witness Lucas referred to productive discussions held between DEC and the Public Staff, resulting in an agreement between DEC and the Public Staff on the method to calculate the price of RECs for such sales. The method was proposed for Commission approval in DEC's recent REPS rider proceeding in Docket No. E-7, Sub 1229. Witness Lucas reiterated in this current DEP REPS proceeding that the Public Staff agrees with this proposal, and recommends that any decision by the Commission on DEC's REC sales also apply to DEP. (Lucas Testimony at 7-9)

Witness Chiu also testified that the Public Staff recommends that approval of the same sales price calculation as proposed by DEC and the Public Staff in DEC REPS Docket No. E-7, Sub 1229, apply to any sales of RECs by DEP to other electric suppliers to assist in their compliance with the requirements of N.C.G.S. §§ 62-133.8(e) and (f). She further testified that the Public Staff recommends continued annual review of the calculation to verify it is working as designed. (Chiu Affidavit at 3-4)

Based on the foregoing and the entire record herein, the Commission concludes the REC sales price calculation proposed by DEC and the Public Staff in DEC's REPS rider proceeding in Docket No. E-7, Sub 1229, as approved or modified by the Commission, shall also be applicable to any animal waste REC sales made by DEP to other electric power suppliers. The Commission also determines that annual review of the calculation is appropriate.

IT IS, THEREFORE, ORDERED as follows:

1. That DEP shall establish the following monthly REPS riders per account (excluding the regulatory fee) that shall remain in effect for a 12-month period beginning on December 1, 2020, and expiring on November 30, 2021: $1.29 for residential, $7.71 for general service, and $54.49 for industrial;

2. That DEP shall establish the following monthly EMF riders per account (excluding the regulatory fee) that shall remain in effect for a 12-month period beginning on December 1, 2020, and expiring on November 30, 2021: $0.00 for residential class, $(0.74) for general service, and $(6.67) for industrial;

3. That DEP shall file the appropriate rate schedules and riders with the Commission in order to implement the provisions of this Order as soon as practicable, but not later than ten days after the date that the Commission issues orders in this docket as well as in Docket Nos. E-2, Sub 1250; E-2, Sub 1253; and E-2, Sub 1254;

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 1250; E-2, Sub 1253; and E-2, Sub 1254, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten days after the Commission issues orders in all four dockets;

5. That DEP's 2019 REPS Compliance Report is hereby approved, and the RECs in DEP's 2019 compliance sub-accounts in NC-RETS shall be retired;

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 continue to include detail on its primary compliance cost exhibits 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 30th day of November, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

DOCKET NO. E-2, SUB 1252

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Progress, LLC for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to N.C. Gen. Stat. § 62-133.9 and Commission Rule R8-69	)))))	ORDER APPROVING DSM/EE RIDER, SUBJECT TO FILING OF FINAL BILLING FACTORS AND PROPOSED CUSTOMER NOTICE

HEARD: On Tuesday, September 15, 2020, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina (Public Witness hearing, Hearing Officer Heather Fennel, Presiding)

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

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

PARTIES AND COUNSEL:

For Duke Energy Progress, LLC:

Kendrick Fentress, Associate General Counsel, Duke Energy Corporation
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Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 E. Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For the Carolina Industrial Group for Fair Utility Rates III:

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

For the North Carolina Sustainable Energy Association:

Benjamin Smith, Regulatory Counsel, 4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

For the North Carolina Justice Center, North Carolina Housing Coalition, and the Southern Alliance for Clean Energy:

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

For the Using and Consuming Public:

Lucy E. Edmondson, Nadia L. Luhr, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: North Carolina General Statute § 62-133.9(d) authorizes the North Carolina Utilities Commission (Commission) to approve an annual rider to the rates of electric public utilities, outside of a general rate case, for recovery of all reasonable and prudent costs incurred for adoption and implementation of new demand-side management (DSM) and energy efficiency (EE) measures. The Commission is also authorized to award incentives to electric companies for adopting and implementing new DSM/EE measures, including, but not limited to, appropriate rewards based on (1) the sharing of savings achieved by the DSM and EE measures and/or (2) the capitalization of a percentage of avoided costs achieved by the measures. Commission Rule R8-69(b) provides that every year the Commission will conduct a proceeding for each electric public utility to establish an annual DSM/EE rider to recover the reasonable and prudent costs incurred by the electric utility in adopting and implementing new DSM/EE measures previously approved by the Commission pursuant to Commission Rule R8-68. Further, Commission Rule R8-69(b) provides for the establishment of a DSM/EE experience modification factor (EMF) rider to allow the electric public utility to collect the difference between reasonable and prudently incurred costs and the revenues that were realized during the test period under the DSM/EE rider then in effect. Commission Rule R8-69(c) permits the utility to request the inclusion of utility incentives (the rewards authorized by the statute), including net lost revenues (NLR), in the DSM/EE rider and the DSM/EE EMF rider.

Docket Proceedings

In the present proceeding, Docket No. E-2, Sub 1252, on June 9, 2020, Duke Energy Progress, LLC (DEP or the Company) filed an application for approval of its DSM/EE rider for 2021 (Application) and the direct testimony and exhibits of Shannon R. Listebarger, Manager – Rates and Regulatory Strategy for Duke Energy Carolinas, LLC and Robert P. Evans, Senior Manager – Strategy and Collaboration for the Carolinas in the Company's Market Solutions Regulatory Strategy and Evaluation group.

On June 29, 2020, the Commission issued an order scheduling a hearing for September 15, 2020, establishing discovery guidelines, providing for intervention and testimony by other parties, and requiring public notice.

On August 7, 2020, the Commission issued an order scheduling a remote hearing for expert witness testimony and requiring parties to file written statements of consent or objection by September 1, 2020, and to file potential cross-examination exhibits by September 10, 2020. All parties filed statements of consent to holding the expert witness hearing by remote means.

The intervention of the Public Staff – North Carolina Utilities Commission (Public Staff) is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e). Carolina Utility Customers Association, Inc. (CUCA), North Carolina Sustainable Energy Association (NCSEA), North Carolina Justice Center (NC Justice Center), North Carolina Housing Coalition (NC Housing Coalition), and Southern Alliance for Clean Energy (SACE), and Carolina Industrial Group for Fair Utility Rates III (CIGFUR) filed petitions to intervene which were granted by the Commission.

On August 17, 2020, DEP filed the supplemental testimony and Exhibit D of witness Evans.

On August 24, 2020, the Public Staff filed a motion for extension of time to file testimony. On August 25, 2020, the Commission granted the motion for extension.

On August 26, 2020, NC Justice Center, NC Housing Coalition and SACE (collectively NC Justice Center, *et al.*), filed the testimony and exhibits of Forest Bradley-Wright, the Energy Efficiency Director for SACE; and the Public Staff filed the testimony and exhibits of Michael C. Maness, Director of the Accounting Division, David Williamson, Utility Engineer in the Electric Section of the Energy Division, and John R. Hinton, Director, Economic Research Division. On August 28, 2020, the Public Staff filed a corrected Exhibit 2 to the testimony of witness Hinton.

On September 4, 2020, DEP filed the rebuttal testimony of Timothy J. Duff and witness Evans.

On September 10, 2020, DEP, the Public Staff, and NC Justice Center, *et al.*, filed a joint unopposed motion to excuse all witnesses from appearing at the September 15, 2020 expert witness hearing. On September 14, 2020, the Commission issued an order granting the motion, accepting all testimony and exhibits into the record, cancelling the expert witness hearing, and requiring the filing of proposed orders and briefs by October 16, 2020.

On September 14, 2020, DEP filed affidavits of publication of public notice as required by the Commission's June 29, 2020 Order.

On September 14, 2020, the Public Staff filed a letter advising the Commission that it had completed its review of DEP's Save Energy & Water Kit Program and found an error in the calculation of impacts which DEP agreed to correct in the Experience Modification Factor (EMF), in next year's DSM/EE rider proceeding.

The case came on for the public witness hearing as scheduled on September 15, 2020. No public witnesses appeared at the hearing.

On September 28, 2020, the Public Staff filed a Motion for Judicial Notice, requesting that the Commission take judicial notice of Late-Filed Exhibit No. 2, filed by DEC and DEP in Docket Nos. E-7, Sub 1214, and E-2, Sub 1219, on September 3, 2020. On October 6, 2020, DEP filed a letter stating that it had no objection to the Public Staff's Motion for Judicial Notice.

On September 30, 2020, the Public Staff filed a letter providing the Commission with the results of its review of the costs incurred for DEP's portfolio of DSM/EE programs during the 12-month period ended December 31, 2019. The Public Staff stated that it had completed its review of test year program costs and found no material differences between the program costs as filed by the Company and the costs as reflected in the supporting documentation examined. The Public Staff also stated that it is of the opinion that the Company has done a good job overall in preventing inappropriate costs from being recorded as DSM/EE program costs. The Public Staff stated that its recommended DSM/EE EMF billing rates remain the rates set forth in the direct testimony and exhibits of DEP witness Listebarger, and for the projected rates DSM/EE rates the rates set forth in the testimony and exhibits of Public Staff witness Maness.

On October 8, 2020, the Commission issued an Order granting the Public Staff's September 28, 2020 Motion for Judicial Notice.

On October 16, 2020, DEP and the Public Staff filed proposed orders, and NC Justice Center, *et al.*, filed a brief.

Cost Recovery Mechanism

On June 15, 2009, in Docket No. E-2, Sub 931, the Commission issued an Order Approving Agreement and Stipulation of Partial Settlement, Subject to Certain Commission-Required

Modifications in DEP's first DSM/EE rider proceeding (Sub 931 Order). In the Sub 931 Order, the Commission approved, with certain modifications, an Agreement and Stipulation of Partial Settlement (Stipulation) between DEP, the Public Staff, Wal-Mart Stores East, LP, and Sam's East, Inc. setting forth the terms and conditions for approval of DSM/EE measures and the annual DSM/EE rider proceedings pursuant to N.C.G.S. § 62-133.9 and Commission Rules R8-68 and R8-69. The Stipulation included a Cost Recovery and Incentive Mechanism for DSM and EE Programs (Original Mechanism), which was modified by the Commission in its Sub 931 Order and subsequently in its Order Granting Motions for Reconsideration in Part issued on November 25, 2009, in the same docket. The Original Mechanism as approved after reconsideration allowed DEP to recover all reasonable and prudent costs incurred and utility incentives earned for adopting and implementing new DSM and EE measures in accordance with N.C.G.S. § 62-133.9, Commission Rules R8-68 and R8-69, and the additional principles set forth in the Original Mechanism.

On January 20, 2015, in Docket No. E-2, Sub 931, the Commission issued an Order Approving Revised Cost Recovery and Incentive Mechanism and Granting Waivers. The Order approved an agreement between DEP, the Public Staff, Natural Resources Defense Council, and SACE proposing revisions to the Original Mechanism, generally to be effective January 1, 2016 (Revised Mechanism). The Revised Mechanism allows DEP to recover all reasonable and prudent costs incurred and utility incentives earned for adopting and implementing new DSM and EE measures in accordance with N.C.G.S. § 62-133.9, Commission Rules R8-68 and R8-69, and the additional principles set forth in the Revised Mechanism.

On November 27, 2017, in Docket No. E-2, Sub 1145 (Sub 1145), the Commission issued its Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice (Sub 1145 Order), in which it approved the agreement to revise certain provisions of the Revised Mechanism reached by the Company and the Public Staff. The Revised Mechanism, as revised by the Sub 1145 Order, is set forth in Maness Exhibit 1 filed in Sub 1145 and is referred to herein as the "Mechanism."

Based upon consideration of DEP's Application, the pleadings, the testimony, and exhibits received into evidence, and the record, 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 and South Carolina, and is subject to the jurisdiction of the Commission as a public utility. DEP is lawfully before this Commission based upon its application filed pursuant to N.C.G.S. § 62-133.9 and Commission Rule R8-69.

2. The test period for purposes of this proceeding extends from January 1, 2019 through December 31, 2019.

3. The rate period for purposes of this proceeding extends from January 1, 2021 through December 31, 2021.

4. DEP has requested approval for the recovery of costs, and utility incentives where applicable, related to the following DSM/EE programs:

Residential

- Appliance Recycling
- EE Education Program
- Multi-Family EE
- My Home Energy Report (MyHER)
- Neighborhood Energy Saver (Low-Income)
- Smart $aver EE Program (formerly, Home Energy Improvement Program)
- New Construction
- EnergyWise Home (Load Control)
- Save Energy and Water Kit
- Energy Assessment
- Low-Income Weatherization Pay for Performance

Non-Residential

- Smart $aver Energy Efficient Products and Assessments (formerly, EE for Business)
- Smart $aver Performance Incentive Program
- Small Business Energy Saver
- Commercial, Industrial, and Governmental (CIG) Demand Response Automation
- EnergyWise for Business

Residential and Non-Residential

- Distribution System Demand Response (DSDR)
- EE Lighting

These programs are eligible for cost and utility incentive recovery, where applicable.

5. For purposes of inclusion in this DSM/EE rider, the Company's portfolio of DSM and EE programs is cost-effective, and the Commission does not direct that any action be taken on any of these programs at this time.

6. Pursuant to Paragraph 19 of the Mechanism, the Neighborhood Energy Saver Program is not required to have a Total Resource Cost test (TRC) or Utility Cost Test (UCT) result greater than 1.0 in order to be eligible for inclusion in the Company's portfolio.

7. The Residential Smart $aver EE Program has failed to demonstrate a prospective TRC result greater than 1.0 in the current proceeding and in the previous five rider proceedings.

8. The transformation of the lighting market with respect to LED non-specialty lighting continues, but to sustain the benefit that low-income customers and multifamily residences obtain from energy efficient A-line bulbs, the Company shall continue to provide energy efficient A-line bulbs to low-income and multifamily residences through its traditional outlets.

9. The Company's proposed Grid Improvement Plan (GIP) has the potential to impact the cost effectiveness of the Company's DSM/EE programs.

10. Although customers are receiving additional and more precise data about their energy usage from smart meters or other channels, these channels do not provide the normative comparison of their usage to that of their peers nor do they empower customers to act on that data the way the Company's MyHER EE program does.

11. With the exception of Evans Exhibit C, the evaluation, measurement, and verification (EM&V) reports filed in this proceeding are acceptable for purposes of this proceeding and should be considered complete for purposes of calculating program impacts. With the exception of Evans Exhibit C, DEP has appropriately incorporated the results of these EM&V reports into the DSM/EE rider calculations.

12. The Company has complied with the Commission's requirement that DEP monitor the changes in annual ratios of allocations between non-DSDR and DSDR equipment and report the degree of change in its annual DSM/EE rider filing. Based on its review, the Company determined that the capacitor allocation ratio should be reduced from 21.08 to 20.48 and the regulator allocation ratio should be elevated from 78.50 to 78.56 percent.

13. The Company included what it termed a 17% reserve margin adder when calculating the avoided capacity costs for purposes of the Company's Vintage 2021 DSM and EE programs.

14. The Company's proposed seasonal allocation of avoided capacity value is consistent with the Commission's most recent avoided cost proceeding and is appropriate for use in this proceeding; however, the seasonal allocation factors should not be applied to the Company's legacy DSM participation and measures.

15. In its direct testimony and exhibits, DEP requested the recovery of NLR in the amount of $38,111,736 and PPI in the amount of $26,905,577 through the EMF component of the total DSM/EE rider, and NLR of $34,768,785 and PPI of $21,191,901 for recovery in the forward-looking, or prospective component of the total rider. DEP's proposed recovery of NLR and PPI is consistent with the Mechanism and is appropriate.

16. For purposes of the DSM/EE rider to be set in this proceeding and subject to review in DEP's future DSM/EE rider proceedings, the reasonable and appropriate estimate of the Company's North Carolina retail DSM/EE program rate period amounts, consisting of its amortized operations and maintenance (O&M) costs, depreciation, capital costs, taxes, amortized incremental administrative and general (A&G) costs, carrying charges, NLR, and PPI, is

$169,481,478 (excluding the North Carolina Regulatory Fee, or NCRF), and this is the appropriate amount to use to develop the forward-looking DSM/EE revenue requirement.

17. For purposes of the EMF component of its DSM/EE rider, DEP's reasonable and prudent North Carolina retail test period costs and incentives, consisting of its amortized O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, are $176,818,282. Therefore, the test period revenue requirement, as reduced by the test period revenues collected and miscellaneous adjustments, is $4,164,100, which is the test period under-collection that is appropriate to use as the DSM/EE EMF revenue requirement in this proceeding.

18. After assignment or allocation to customer classes in accordance with N.C.G.S. § 62-133.9, Commission Rule R8-69, and the Commission Orders in Docket No. E-2, Sub 931, the revenue requirements for each rate class, excluding the North Carolina Regulatory Fee (NCRF), are as follows:

DSM/EE PROSPECTIVE COMPONENT:

Residential	$ 101,755,267
General Service EE	$ 60,785,477
General Service DSM	$ 6,600,295
Lighting	$ 340,439
Total	$ 169,481,478

DSM/EE EMF:

Residential	$ 1,988,124
General Service EE	$ 3,131,509
General Service DSM	$ (931,458)
Lighting	$ (24,075)
Total	$ 4,164,100

19. The appropriate and reasonable North Carolina retail class level kilowatt hour (kWh) sales for use in determining the DSM/EE and DSM/EE EMF billing factors in this proceeding are:

Rate Class	kWh Sales
Residential	15,893,328,062
General Service EE	9,132,663,985
General Service DSM	9,064,020,676
Lighting	356,925,937

20. The appropriate DSM/EE EMF billing factors, excluding NCRF, are: 0.013 cents per kWh for the Residential class; 0.034 cents per kWh for the EE component of the General Service classes; (0.010) cents per kWh for the DSM component of the General Service classes, and (0.007) cents per kWh for the Lighting class. The factors do not change with the NCRF included.

21. The appropriate forward-looking DSM/EE rates to be charged by DEP during the rate period, excluding NCRF, are: 0.640 cents per kWh for the Residential class; 0.666 cents per kWh for the EE component of the General Service classes; 0.073 cents per kWh for the DSM component of the General Service classes; and 0.095 cents per kWh for the Lighting class. The appropriate forward-looking DSM/EE rates to be charged by DEP during the rate period, including NCRF, are: 0.641 cents per kWh for the Residential class; 0.667 cents per kWh for the EE component of the General Service classes; 0.073 cents per kWh for the DSM component of the General Service classes; and 0.095 cents per kWh for the Lighting class.

22. The appropriate total DSM/EE annual riders including the forward looking and the EMF rate (including NCRF) for the Residential, General Service, and Lighting rate classes are increments of 0.654 cents per kWh for the Residential class, 0.701 cents per kWh for the EE portion of the General Service class; 0.063 cents per kWh for the DSM portion of the General Service class, and 0.088 cents per kWh for the Lighting class.

23. DEP should continue to leverage its collaborative stakeholder meetings (Collaborative) to expand on the existing discussions related to the expansion and improvements of low-income EE programs, EM&V issues, and other program design issues raised in the testimony of NC Justice Center, *et al.*, witness Bradley-Wright and provide a summary of those discussions in the Company's next DSM/EE rider filing.

24. The Company should continue Collaborative meetings so that the combined DEP/Duke Energy Carolinas, LLC (DEC) Collaborative meets every two months.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact, which is supported by DEP's Application, is essentially informational, procedural, and jurisdictional in nature, and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2-3

No party opposed DEP's proposed rate period and test period. The rate period and test period proposed by DEP are reasonable and consistent with the Mechanism approved by the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact can be found in DEP's Application, the testimony and exhibits of DEP witnesses Listebarger and Evans, the testimony of Public Staff witness Williamson, and various Commission orders in program approval dockets.

DEP witness Listebarger's testimony shows the portfolio of DSM/EE programs that is associated with the Company's request for approval of this rider. (Listebarger at 4-7.) The direct testimony of DEP witness Evans lists the DSM/EE programs for which the Company is requesting cost recovery, and incentives where applicable, in this proceeding. (Evans Direct at 17-18.) Those programs are:

Residential

- Appliance Recycling
- EE Education Program
- Multi-Family EE
- MyHER
- Neighborhood Energy Saver (Low-Income)
- Smart $aver EE Program (formerly, Home Energy Improvement Program)
- New Construction
- EnergyWise (Load Control)
- Save Energy and Water Kit
- Energy Assessment
- Low-Income Weatherization Pay for Performance

Non-Residential

- Smart $aver Energy Efficient Products and Assessments (formerly, EE for Business)
- Smart $aver Performance Incentive Program
- Small Business Energy Saver
- CIG Demand Response Automation
- EnergyWise for Business

Residential and Non-Residential

- DSDR
- EE Lighting

(*Id.*)

In his testimony, Public Staff witness Williamson also listed the DSM/EE programs for which the Company seeks cost recovery and noted that each of these programs has received approval as a new DSM or EE program and is eligible for cost recovery in this proceeding under N.C.G.S. § 62-133.9. (Williamson at 6-7.)

Thus, the Commission finds and concludes that each of the programs listed by witnesses Evans and Williamson has received Commission approval as a new DSM or EE program and is, therefore, eligible for cost recovery in this proceeding under N.C.G.S. § 62-133.9.

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

The evidence for these findings can be found in the testimony and exhibits of Company witness Evans, the testimony and exhibits of Public Staff witness Williamson, and the testimony of NC Justice Center, *et al.*, witness Bradley-Wright.

DEP witness Evans testified that the Company reviewed the portfolio of DSM/EE programs and performed prospective analyses of each of its programs and the aggregate portfolio for the Vintage 2021 period, the results of which are incorporated in Evans Exhibit No. 7. (Evans Direct at 18-19.) He noted that the Company's aggregate portfolio continues to project cost-effectiveness. (*Id.*) DEP's calculations, however, indicate that the following programs do not pass the TRC threshold of 1.00: the Neighborhood Energy Saver Program, which was not cost-effective at the time of approval, but was instead approved based on societal benefits; Residential Smart $aver EE Program; and EnergyWise for Business. (Evans Ex. 7.)

Witness Evans noted that the cost-effectiveness for EnergyWise for Business Program is a concern with its 0.52 TRC score and reported that the Company is reviewing the program to determine if it can increase its cost-effectiveness or if discontinuation is appropriate. Witness Evans committed the Company to providing the Commission with further information regarding the program's continuation in the filing of its 2021 cost recovery request. (Evans Direct at 19.)

Public Staff witness Williamson stated in his testimony that he reviewed DEP's calculations of cost-effectiveness under each of the four standard cost-effectiveness tests – the Utility Cost (UC), TRC, Participant, and Ratepayer Impact Measure (RIM) tests. (Williamson at 10.) The Public Staff also compared the cost-effectiveness test results in previous DSM/EE proceedings to the current filing and developed a trend of cost-effectiveness that serves as the basis for the Public Staff's recommendation of whether a program should be terminated. (*Id.* at 12.) Witness Williamson testified that although many programs continue to be cost-effective, the TRC and UC scores as filed by the Company for all programs have a natural ebb and flow over time, mainly due to changes in avoided costs and updated EM&V and program participation. (*Id.* at 12-14 and Williamson Exhibit 2.) Witness Williamson concluded that the rolling record of cost-effectiveness results confirms that activities within the portfolio have been and continue to be reasonable. (*Id.* at 14.)

The Commission concludes that DEP's portfolio of DSM and EE programs is cost-effective and eligible for inclusion in the Company's DSM/EE rider. Below, the Commission makes specific findings and conclusions as to the individual programs that concern the Public Staff.

EE Lighting

Public Staff witness Williamson testified that the goal of utility-sponsored EE programs is to build customer acceptance and adoption of EE technologies. He further testified that as technologies become more energy efficient, costs decrease and consumer acceptance increases. (Williamson at 18.) With respect to EE lighting, he noted that the Public Staff had previously highlighted several trends in the adoption of EE lighting measures, including the likelihood that the non-specialty LED would become the baseline standard for general service bulb technologies by January 2020, thereby decreasing savings from any EE program that continued to include general service bulb technologies. He testified that the United States Department of Energy (DOE) had previously published final rules for the second phase of the 2007 Energy Independence and Security Act (EISA). These final rules, EISA 2020, were to become effective January 1, 2020, and they had adopted revised definitions for the general service lamp (GSL) and the general service incandescent lamp (GSIL). In 2019, however, the DOE ultimately determined that amending the energy conservation standards for GSILS would not be economically justified. (*Id.* at 17.) Witness Williamson stated that the Public Staff continues to believe that the EE lighting market has transformed at a faster rate than was initially recognized, as a result of EISA's changes to federal lighting standards since 2007 and customer preference for LEDs. Thus, he concluded that non-specialty LED lighting should be considered the baseline standard for general service bulb technologies. (*Id.* at 17-18.)

Witness Williamson relayed that the Company had begun to minimize the impacts of EISA 2020 in updating its programs that incorporate lighting-related products to offer specialty LED bulb technologies as the only lighting offering. The Public Staff agreed with this approach; however, based on its review of the Company's lighting-related EM&V reports for the last three years, the Public Staff recommended that the Commission require that, beginning in 2021, only specialty LED lighting be considered for recognition as energy efficiency. (*Id.* at 18-19.)

In his rebuttal testimony, Company witness Evans agreed that significant market transformation with respect to LED non-specialty lighting had taken place, but he disagreed that the transformation was universal. Witness Evans reported an ongoing need for non-specialty energy efficient A-line bulbs in both low-income and multifamily residences to enable those customers to participate in the benefits of energy efficient lighting. Therefore, the Company intended to continue to provide A-line bulbs to low-income customers through its direct install Neighborhood Energy Saver Program and to provide them through outlets such as Goodwill, Dollar General, Dollar Tree and Habitat Stores. Witness Evans also testified that the Company intended to replace inefficient lighting through its Multifamily direct install program. Future needs in low-income and multifamily residences will be closely monitored through independent EM&V studies for these programs to determine their saturation with standard high efficiency lighting. (Evans Rebuttal at 3-4.)

Grid Improvement Plan

With respect to DEP's proposed Grid Improvement Plan (GIP), which is pending approval in the DEP general rate case in Docket No. E-2, Sub 1219, witness Williamson testified that he was concerned that GIP would impact the MyHER program and the proposed conversion of DSDR to Conservation Voltage Control (CVR) and how that conversion would impact the current DSM and EE portfolio.

MyHER

Witness Williamson testified that GIP would enhance capacity, data analytics/collection, and power flow capabilities on almost all circuits within the service territory. He indicated that these GIP enhancements would thus impact the savings achieved through the DSM/EE portfolio, especially the savings associated with the MyHER program. Witness Williamson's concern resulted from his opinion that the success of that program relies on the Company's collection of individual customers' data and resulting analysis of that data in relation to similar, nearby customers. (Williamson at 22-23.) The deployment of Advanced Metering Infrastructure (AMI), which witness Williamson described as a "crucial component" of GIP, is expected to be used for better rate design opportunities and to provide customers with interval usage data. (*Id.* at 23.) Witness Williamson also discussed the Company's Energy Mobile App, which allows participants to see their usage comparison and disaggregation, as well as the new AMI usage charts, which show customers the difference in the average weekly usage by hour from one month to the next, both of which were launched in 2019. The Company has also recently made available to customers a functionality like Green Button Download, enabling customers to download their usage data in a standard format. (Williamson at 23-24.) Witness Williamson concluded that through these services and access to data, the MyHER program will duplicate the provision of the same data to customers in other forms, with the only incremental difference being the EE tips the MyHER report provides to customers. Thus, witness Williamson expressed skepticism that the cost and utility incentives associated with the MyHER program are justified. He recommended that the Company assess the costs and benefits of continuing to offer the MyHER program. (Williamson at 24-25.)

In his rebuttal testimony, witness Evans disagreed with witness Williamson's recommendation on MyHER, noting that his testimony ignores that the MyHER report provides the normative comparison of a customer's usage to the usage of a similar group of customers, as well as to a model Efficient Home. The normative comparison is not included in the other methods of simply viewing customer usage data he referenced in his testimony. Instead witness Evans noted that customers' ability to see their own usage in comparison to their peers and the modeled Efficient Home is a value to customers. In support, he stated that the Commission recognized that value when concluding that MyHER has the potential to encourage EE by providing participants with periodic personalized reports containing comparative usage date for similar residences in the same geographic area and personalized recommendations. (Evans Rebuttal at 5-6.) Witness Evans concluded that, although customers may access their own AMI data to monitor their own usage, without having a way to compare their usage to their peers and Efficient Home, they have no way to otherwise understand their own usage in the context of how they compare to similar customers. (Evans Rebuttal at 6.)

Proposed CVR Conversion

Witness Williamson's other concern with the Company's planning to modernize the grid is the impact these enhancements could have on DSM/EE programs and cost recovery. Witness Williamson testified that the proposed CVR component of the Company's GIP proposal will begin in 2021. This conversion will allow the current assets of DSDR to deliver a constant and consistent voltage reduction on the electric grid across all circuits designed to operate under CVR. Witness Williamson explained that the Company anticipated that the CVR mode will be active approximately 90% of the time and that when it is activated, it will provide two percent voltage reduction to 98% of the DSDR circuits across the North Carolina service territory. (Williamson at 26.) He indicated that the Company had not assessed the potential impacts of the reduced energy or demand savings that will result from the CVR initiative, but he said the Company noted that the impacts will be reflected in future cost-effectiveness evaluations. Witness Williamson predicted that if the CVR conversion resulted in impacts to energy and demand savings, then energy and demand savings for all DSM and EE programs, including DSDR, will be reduced "to some degree." (Williamson at 26-27.) Witness Williamson described DSDR as intertwined with the Company's day-to-day grid activities, which produce certain efficiencies for customers. He noted that DSDR had allowed DEP to achieve peak shaving voltage reduction throughout the DEP distribution system during its activation. DEP's significant circuit conditioning, including the installation of substation and distribution voltage regulating devices and capacitators, telecommunications and IT infrastructure, and some balancing of load on distribution circuits, enabled these peak shaving voltage reductions. (Williamson at 27.)

Witness Williamson also relayed that the Company detailed how the CVR capabilities are critical to enable greater application of Distributed Energy Resources on the grid and that these capabilities depend on the DSDR infrastructure. According to witness Williamson, because of the differences in cost recovery mechanisms, DSDR is treated differently than normal operational efficiency improvements. DSDR, he testified, receives "special" rate making treatment in DEP's DSM/EE rider, which some customers may opt out of, unlike normal and routine grid work, where costs are depreciated and allocated to all customer classes. (Williamson at 30-31.) He then opined that the need to differentiate between DSDR grid support work and GIP grid support work may no longer be needed.

Witness Williamson had also highlighted the potential for overlap between the Company's GIP and DSDR in the last DEP rider proceeding, and, in this proceeding, he identified specific overlaps in Capacitor Bank Controls, 2G/3G modem replacements to support 4G/5G and Gid/WAN Core routers. He also noted that a portion of the sensor equipment is being retired from DSDR and replaced as part of the Self-Optimizing Grid (SOG) and he specified that the costs associated with SOG are not charged to DSDR. (Williamson at 31.)

Witness Williamson did not recommend the removal or adjustment of any costs to be recovered from the Company's proposed DSM/EE rider based on his GIP concerns. Because the Company continues to implement GIP and as its grid capabilities and services continue to evolve, he recommended that the Commission direct the Company to:

- Analyze GIP to explain how it will affect DSM/EE programs' ability to produce peak demand and energy savings and file the results no later than the Company's next DSM/EE rider proceeding;

- Explain how the Company will distinguish peak demand and energy saving resulting from GIP from those resulting from DSM/EE in the next DSM/EE rider proceeding;

- List GIP projects that have been implemented and how they have affected the Company's DSM/EE portfolio's performance if at all.

In his rebuttal testimony, Company witness Evans disagreed with Public Staff witness Williamson's recommendations and responded to his concerns. With respect to the recommendation that the Company analyze how GIP will affect the performance of DSM/EE programs and include reporting on GIP implementation in the next DSM/EE rider proceeding, witness Evans noted that the Company had already provided voluminous amounts of data to the Public Staff in response to their and other intervenors' data requests in the pending DEP rate case and the pending Duke Energy Carolinas, LLC rate case with respect to the Integrated Volt/Var Controls (IVVC). The Company does not oppose providing information about the DSDR conversion to CVR and has already agreed to work with the Public Staff on reporting GIP programs as outlined in the Company's Second Amendment and Partial Settlement with the Public Staff in the pending DEP rate case. Moreover, the direct and rebuttal testimony of Duke witness Jay W. Oliver in the pending rate cases addressed GIP status extensively. Witness Evans noted that because the DSM/EE programs and the GIP were separate initiatives with different goals, integrating additional GIP status reporting would likely lead to confusion. Further, because no party, including the Company, has recommended that the Company file any GIP program for consideration as part of the DSM/EE rider, witness Evans did not support using the DSM/EE rider proceeding as an appropriate forum for the types of information Public Staff witness Williamson recommended for inclusion in the next DSM/EE rider proceeding. Thus, witness Evans concluded that additional analysis recommended by the Public Staff would be duplicative and is not necessary. He further stated that any influence or interaction between GIP and DSM/EE programs will be evaluated and captured in existing reporting protocols. (Evans Rebuttal at 9-10.)

Witness Evans also stated that Public Staff witness Williamson's recommendation that the Company explain in its next DSM/EE rider filing how it will distinguish peak demand and energy savings resulting from the GIP from those resulting from the DSM/EE portfolio is premature. Deferral accounting for the GIP program remains pending in DEP's general rate case. Thus, the Company has not completed testing and analysis of changing its operational strategy from DSDR to CVR. (Evans Rebuttal at 10-11.)

Neighborhood Energy Saver Program

Witness Evans testified that the Neighborhood Energy Saver (NES) Program, which was not cost-effective at the time of Commission approval, is not projected to be cost-effective for the Vintage 2021 period. (Evans Direct at 19.)

Pursuant to Paragraph 19 of the Mechanism (which provides an exception for low-income programs and other non-cost-effective programs with similar societal benefits), the NES program is not required to pass the TRC or UCT tests to be eligible for inclusion in the Company's portfolio. Accordingly, the Commission finds and concludes that no further action by the Company is required with respect to this program.

Residential Smart $aver EE Program

In his direct testimony, DEP witness Evans indicated that the Residential Smart $aver EE program is not projected to be cost-effective for the Vintage 2021 period. (*Id.*) The Company projected a TRC score of 0.40 for the program for Vintage 2021. (Evans Exhibit 7)

Witness Williamson described the Public Staff's review of the Residential Smart $aver program, which offers rebate options to customers for a variety of EE measures related to home heating and cooling to encourage energy efficiency. (Williamson at 37.) In 2016, to offset costs associated with this program and to improve its cost-effectiveness, the Commission approved the Company implementing a referral channel as part of this program. Additionally, witness Williamson noted that an on-line option store was added in 2017. Witness Williamson testified that the referral channel now includes referrals beyond its original scope of focusing on HVAC equipment referrals. The referral channel, under the name FindItDuke, now includes referrals to rooftop solar systems, plumbing and tree removal services. All funds that DEP receives from customers participating in the FindItDuke, including funds from referrals for services that are beyond the original scope of the channel, are used to offset the Smart$aver program costs. Witness Williamson noted that funds from the rooftop solar and tree service contractors are only a very small portion of the overall revenues received. (Williamson at 38-40.) The Public Staff did not contend that the Company had violated any Commission Rules or Flexibility Guidelines in expanding the referral channel, but did opine that the expansion of referrals beyond DSM and EE programs seemed as if it should have been brought to the NCUC's review in advance of the change. The Public Staff will continue to discuss this matter with the Company, but it did not recommend that the Commission take any other actions with respect to this program. (*Id.* at 40-41.)

The Commission, however, notes that the Residential Smart $aver EE program has failed to demonstrate a prospective TRC result greater than 1.0 in the current proceeding and in the last five rider proceedings: Subs 1070, 1108, 1145, 1174, 1206, and 1252. Paragraph 23 of the Mechanism requires the Company, in each annual DSM/EE cost recovery filing, to perform prospective cost-effective test evaluations for each of its approved DSM and EE programs. Pursuant to Paragraph 23B of the Mechanism, when a program initially demonstrates a prospective TRC of less than 1.0, the Company must include a discussion in its annual DSM/EE rider proceeding concerning actions being taken to maintain or improve cost-effectiveness, or, alternatively, plans to terminate the program. Pursuant to Paragraph 23C, if a program demonstrates a prospective TRC of less than 1.0 in a second DSM/EE rider proceeding, the Company must include a discussion in its annual filing concerning what actions it has taken to improve cost-effectiveness. Pursuant to Paragraph 23D, if a program demonstrates a prospective TRC of less than 1.0 in a third DSM/EE rider proceeding, the Company must terminate the program, unless otherwise ordered by the Commission. Despite numerous modifications over recent years[1] the Residential Smart $aver EE program has now demonstrated a prospective TRC of less than 1.0 in a sixth consecutive DSM/EE rider proceeding. The Commission is of the opinion that it is necessary to determine whether there are steps that can be taken to improve the cost-effectiveness of the program, or whether the program should be terminated.

Based on the foregoing, the Commission determines that no changes are required to the Company's Residential Smart $aver EE program. The Commission also finds and concludes that if the program continues to demonstrate a prospective TRC result of less than 1.0 for the Vintage 2022 forecast in the next rider proceeding, the Company should include in its next rider filing a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program.

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[1] On February 9, 2016, in Docket No. E-2, Sub 936, the Commission approved the Company's request to implement a referral channel to offset some of the costs associated with the program. On September 11, 2017, in the same docket, the Commission approved the conversion of Home Energy Improvement Program (HEIP) into what is now known as the Smart $aver program. Most recently, on February 25, 2019, the Commission in Dockets E-2 Sub 936 and E-2 Sub 1174 approved modifications to the program to reduce costs, implement a three-year transition to a referral-only channel and introduce an online channel.

Conclusions

No party challenged inclusion of the above listed programs in the Company's DSM/EE rider for cost recovery. Because the Commission is concerned that low-income and multifamily residences continue to share in the benefits of energy efficient lighting, it declines to adopt the Public Staff's recommendation that it consider only specialty LED lighting for recognition as energy efficiency in these proceedings. Instead, to sustain the benefit that low-income customers and multifamily residences obtain from A-line bulbs, the Commission directs the Company to continue to provide A-line bulbs to low-income customers through its direct install Neighborhood Energy Saver program and to provide them through outlets such as Good Will, Dollar General, and Habitat stores. The Commission further approves the Company's proposal to continue replacing inefficient lighting through its Multifamily direct install program. The Company should continue to closely monitor the future needs of low-income and multifamily residences as independent EM&V studies for these programs to determine their saturation with standard high efficiency lighting.

With respect to witness Williamson's recommendations concerning the GIP, the Commission finds and concludes that the potential impacts of the Company's proposed GIP on the cost effectiveness of the Company's DSM/EE programs warrants further examination. The Commission has received and reviewed voluminous evidence on GIP implementation in the pending general rate cases, especially through the direct and rebuttal testimony of Jay W. Oliver. Additional status reporting in the DSM/EE docket will only duplicate reporting done in other proceedings and complicate the already extensive reporting requirements in the DSM/EE proceedings. As witness Evans proposed, the more effective method for conveying GIP impacts on the DSM/EE portfolio for purposes of the DSM/EE rider proceedings is through EM&V reporting protocols that are already submitted in these proceedings.

With respect to the question of whether the additional analyses recommended by witness Williamson will be adequately covered by EM&V analyses, the Commission is not persuaded that a yearly analysis of any impacts on cost effectiveness will be essential to evaluating the Company's DSM/EE portfolio during each year's rider proceeding, and concludes that the existing EM&V reporting protocol is sufficient. The Commission further concludes that some information concerning the status of its GIP initiatives and their effects on DSM/EE programs could be helpful in its DSM/EE rider proceedings and, therefore, finds that the Company shall in the next rider proceeding (1) explain how the Company will distinguish peak demand and energy savings between GIP and DSM and EE programs; and (2) provide a list of GIP projects that have been implemented and explain how those projects have affected the performance of the Company's DSM/EE portfolio, if at all.

With respect to the recommendation that the Company explain in its next rider proceeding how it will distinguish peak demand and energy savings resulting from the GIP from those resulting from the DSM/EE Portfolio, the Commission agrees that the shift from DSDR to CVR would affect the amount of maximum peak shaving capability. However, with the pending CVR component not beginning until 2021, the Company has not yet had time to test and analyze data related to the reduction in peak shaving and will likely not have time before the next rider proceeding. Thus, the Commission concludes that compelling DEP to include information on projected future impacts on the DSM/EE portfolio is premature and unnecessary at this time. The Commission recognizes that there is a distinction between a customer receiving additional and more precise data about their energy usage from smart meters or from the smart meter usage applications, which do not act as energy efficiency programs, and a utility program, like MyHER, that engages customers through normative comparison of their usage to that of their peers and empowers customers to act on that data. The Commission acknowledged that distinct and critical component of the MyHER program when it approved the program for DEC, stating that MyHER "has the potential to encourage EE by providing participants with periodic personalized reports containing comparative usage data for similar residences in the same geographic and personalized recommendations for more efficient use of energy in their homes, which should motivate participants to better manage and reduce their energy consumption." Order Approving Program, Docket No. E-7, Sub 1015, issued Sept. 11, 2012 at 6. Therefore, the Commission declines to accept the Public Staff's request to direct the Company to reassess continuing its successful MyHER program at this time.

Finally, the Commission agrees with Public Staff witness Williamson that the Company has not violated the flexibility guidelines or any Commission rules or orders in implementing the Residential Smart $aver EE Program's referral channel. The Commission directs the Public Staff and the Company to continue to discuss the matter as recommended by witness Williamson. To the extent that the program continues to demonstrate a prospective TRC result of less than 1.0 for vintage 2022, the Company should include in its next rider filing a discussion of the actions being taken to maintain or improve cost effectiveness, or alternatively, its plans to terminate the program.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this finding of fact can be found in the testimony and exhibits of DEP witness Evans and the testimony of Public Staff witness Williamson.

DEP witness Evans testified regarding the EM&V process, activities, and results presented in this proceeding. (Evans Direct at 22-25.) He explained that the EMF component of the Company's DSM/EE rider incorporates actual customer participation and evaluated load impacts determined through EM&V and applied pursuant to the Revised Mechanism. (*Id.*) In this proceeding, the Company submitted, as exhibits to witness Evans' testimony, detailed completed EM&V reports or updates for the following programs:

- My Home Energy Report – June 2017 through May 2018 (Evans Exhibit A)
- Neighborhood Energy Saver Program – 2018 (Evans Exhibit B)
- Save Energy and Water kits – 2018-2019 (Evans Exhibit C)
- Commercial, Industrial, and Governmental Demand Response Automation Program - 2018 (Supplemental Evans Exhibit D)

In his testimony, Public Staff witness Williamson testified that the Company is complying with the various Commission orders regarding EM&V of their DSM/EE portfolio. He did, however, make recommendations to the Commission on the EM&V report for the Residential

Income-Qualified EE program (NES) (Evans Exhibit B) and the Save Energy and Water Kit (SEWK) program (Evans Exhibit C.) (Williamson at 42.)

With respect to the NES program, witness Williamson described his review of Evans Exhibit B, which evaluated the performance of the NES program from June 1, 2017 through June 30, 2018. (*Id.*) He testified that Evans Exhibit B is acceptable for purposes of verifying the NES program savings. (Williamson at 45.) Witness Williamson recommended, however, that the evaluator of the NES program use a billing analysis to determine program savings in the next evaluation of the NES program in 2021. (Williamson at 45.) Witness Williamson explained that the evaluator used an engineering analysis that relied on information from other sources. Witness Williamson reported that the evaluator had indicated that a billing analysis was not appropriate in this evaluation because of the difference in usage patterns between the treatment group and the control group and the differences in weather patterns between pre- and post-treatment periods. Witness Williamson testified that a billing analysis was preferable to an engineering analysis, however, because a billing analysis is more accurate on program performance. He further indicated that the engineering analysis in this case produces per participant savings that are double the savings from the previous evaluation. (Williamson at 42-43.)

Witness Williamson also testified that the engineering analysis in this case assumes a net-to-gross (NTGR) of 1.0, which is standard practice for income-qualified programs. The Public Staff recognizes this to be a standard practice, although witness Williamson noted that lighting accounts for 37% of NES's gross savings and the lighting market has significantly changed in recent years. The evaluation indicates that many bulbs could not be installed because efficient bulbs were already present. He testified that the issue was further complicated because the engineering analysis assumes baseline wattage is equal to the federal standard (equivalent to a halogen bulb) when at the time of the evaluation, halogen bulbs likely only represented a small fraction of shelf space at stores selling bulbs to prospective lighting purchasers. During 2017-2018, LEDs and CFLs were already occupying much of the available shelf-space at big box stores. To witness Williamson, this suggested that the NTGR assumption as well as the presumed baseline wattage in the engineering analysis may over-estimate the LED bulb savings component of the program. (Williamson at 43-44.) Witness Williamson concluded that the Company should perform the next evaluation of the NES program as soon as possible, and reported that the Company had agreed to do so. (*Id.*)

Company witness Evans testified in rebuttal that DEP agreed with Public Staff witness Williamson that a billing analysis method is preferable to an engineering evaluation method to determine program savings for the NES program. He requested flexibility, however, if the results of the billing analysis determined that methodology was not appropriate. Witness Evans stated that the independent evaluator anticipates utilizing a billing analysis for the next NES evaluation; however, witness Evans added caveats for this methodology. First, he cautioned that, should the billing analysis determine that inherent consumption differences cannot be controlled between the group of participants being evaluated (treatment group) versus the control group, utilizing an engineering analysis is better because he agreed that an engineering analysis is an acceptable method. (Evans Rebuttal at 7-8.) Witness Evans also testified that an NTGR is standard practice for income-qualified programs; the independent evaluator will examine whether NTGR is applicable for this program, and more specifically, this jurisdiction. If feasible, the evaluator will investigate framing free ridership questions as they relate to the broader lighting market and will review whether a baseline wattage assumption is appropriate given the region, target population, and types of lamps included in the program. Finally, witness Evans clarified that the Company did not agree that the Company would conduct an NES evaluation as soon as possible with a target completion date on or before 2021. Because of the COVID-19 pandemic, the Company suspended in-home NES operations in March 2020 and has not yet resumed normal operations. Witness Evans committed to work through the evaluation activities as quickly as possible after suspension but noted that it may be impossible for the Company to complete the evaluation with a 2021 timeframe. (Evans Rebuttal at 8-9.)

On September 14, 2020, the Public Staff filed a letter advising the Commission that it had completed its review of DEP's SEWK and found an error in the calculation that DEP agreed to correct in the EMF of next year's DSM/EE rider proceeding.

With the exception of Evans Exhibit C, no party contested the EM&V information submitted by the Company. The Commission therefore finds that the EM&V reports filed as Evans Exhibits A and B and Evans Supplemental Exhibit D are acceptable for purposes of this proceeding and should be considered complete for purposes of calculating program impacts. Further, the Commission concludes that DEP is appropriately incorporating the results of Evans Exhibits A and B and Evans Supplemental Exhibit D into its DSM/EE rider calculations.

With respect to Evans Exhibit C, the Commission will hold open review of the SEWK Program EM&V report until the Company's 2021 DSM/EE rider proceeding.

The Commission additionally concludes that the evaluator of the NES program should use a billing analysis to determine program savings in the next evaluation of the NES program, but, as requested by DEP witness Evans, the evaluator shall maintain flexibility if the results of the billing analysis establish that the methodology was not appropriate. The Commission further directs DEP to conduct an evaluation of NES as soon as possible, but recognizes that with the suspension of in-home NES operations, an evaluation may not be able to be completed with a 2021 timeframe.

Based upon the testimony and evidence cited above, the Commission finds the net energy and capacity savings derived from the EM&V to be reasonable and appropriate. Further, the Commission concludes that DEP is appropriately incorporating the results of EM&V into the DSM/EE rider calculations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence for this finding of fact can be found in the testimony of DEP witness Evans.

The Commission's Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice, issued November 16, 2015, in Docket No. E-2, Sub 1070, directed DEP to file all changes in annual ratios of allocations between non-DSDR and DSDR equipment, report the degree of change in its annual DSM/EE rider filing, and provide such changes to the Public Staff as they become available. Witness Evans informed the Commission that the Company conducted a review of 2018 units during the summer of 2019 and determined that the capacitor allocation ratio should be reduced from 21.08% to 20.48%, and the regulator allocation ratio was elevated from 78.50% to 78.56%. Witness Evans indicated that the 2019 units would be reviewed during summer 2020, and any further changes would be communicated to the Public Staff and implemented on January 1, 2021. (Evans Direct at 14-15.) The Commission concludes that DEP should continue to file reports of changes to its allocations between non-DSDR and DSDR equipment in future proceedings and provide the Public Staff with information on any changes to the allocation factor as they become available.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this finding of fact can be found in the testimony and exhibits of DEP witness Duff and the testimony of Public Staff witnesses Hinton and Williamson.

The Public Staff opposed the Company's inclusion of what it called a 17% reserve margin adder for the demand reduction benefits created by energy efficiency programs. Public Staff witness Hinton acknowledged that prior to the 2012 merger of DEP's parent corporation with Duke Energy Corporation, DEP maintained that its use of the Strategist Model included a reserve margin adjustment. Since the merger, however, DEP's IRP process had largely followed modeling practices of DEC, which, until its 2020 DSM/EE rider filing in Docket No. E-7, Sub 1230, had not proposed a reserve margin adjustment for demand-side resources.

Witness Hinton explained that in DEP's Integrated Resource Plan (IRP), DEP reduces its peak load by the amount of the demand reduction from EE programs, which DEP considers to be a demand-side resource, as shown in the Load, Capacity, and Reserve (LCR) Tables included in DEP's IRP. He acknowledged the Company's argument that since it increases the amount of supply-side resources required to meet the projected peak load by a 17% reserve margin, a similar reserve margin adjustment would be appropriate for demand-side resources, but ultimately, witness Hinton was not persuaded that a 17% reserve margin adder to the avoided capacity cost is appropriate. (Hinton at 8.) To illustrate the reserve margin adjustment's effect on the IRP, witness Hinton referred to DEP's 2018 IRP Winter Projections from the LCR table for years 2019-2025. He explained that in 2021, DEP projected generating reserves of 2,405 MW, for an actual reserve margin of 17.0 percent. If DEP had 100 MW less EE during 2021, the load forecast would be increased by 100 MW 14,251. By shifting to a supply side resource, DEP maintained that, from a planning standpoint, it would effectively increase its 2021 load serving capacity by 117 MW to 2,522 MW. (Hinton at 9-10.)

Witness Hinton acknowledged that "from a resource planning perspective" DEP had a theoretical basis, as shown in the table in his testimony, for valuing MW reductions from EE programs differently from DSM programs. He questioned, however, whether it was logical for customers to pay 17% more for the same MW reduction from an EE program as they did for a DSM program. In other words, witness Hinton pointed out that the weakness in DEP's argument is the inequity of asking customers to pay 17% more for the same MW reduction from an EE program versus from a DSM program. Again, witness Hinton acknowledged that DEP has a theoretical basis from a planning standpoint, but he described it as deficient from a ratemaking standpoint. (Hinton at 11.) Witness Hinton disagreed that customers benefit from DEP's inclusion of the reserve margin in the short-run and testified it was unclear if they would realize any value in the long-run. He noted that the Company's EE reductions from their EE program were not any greater, but he stated that the resource was instead awarded a higher value from a planning perspective, which he contended resulted in the Company's increasing the avoided cost benefits. This, he testified, ultimately would increase the Company's PPI and result in higher earnings. (Hinton at 10-11.)

Finally, witness Hinton argued that including the 17% reserve margin was inconsistent with the Mechanism, which provides how capacity benefits should be determined. The Mechanism provides that the PPI would be derived from the underlying resource plan, production cost model and cost inputs that generated the avoided capacity and avoided energy credits reflected in the Biennial Determination of Avoided Cost Rates from Electric Utility Purchase from QFs as of December 31 of the year immediately preceding the date of the annual DSM/EE rider filing. Witness Hinton cited his previous testimony in another docket to further support his contention that this proceeding is not the appropriate one to evaluate such a significant change to the avoided capacity costs; instead, according to witness Hinton, changes to the dollar savings of avoided energy costs benefits should be evaluated in the context of the Mechanism. (Hinton at 15.) Witness Hinton testified that the reserve margin was not a component of current Biennial Determination of Avoided Cost Rates. Moreover, witness Hinton argued that the proposal effectively increases what customers will pay for the avoided capacity cost benefits of the EE programs by increasing the avoided capacity cost rate above the approved rates. The approved rate is composed of an approved annual combustion turbine (CT) carrying cost and, among other factors, a Performance Adjustment Factor (PAF). Witness Hinton testified that the approved PAF of 5% is a multiplier that increases the annual CT carrying cost which, according to DEP, should be increased by an additional 17%. From this perspective, the impact of this adjustment increases the value of the avoided demand reduction benefits by approximately 23% over the cost of a CT. (Hinton at 12-13.)

DEP witness Duff testified that addition of the reserve margin factor in determining the avoided cost value of EE programs for Vintage 2021 reflects their treatment in the IRP. He explained that because EE is treated as a load reduction resource in the IRP, instead of a load serving resource, it should have a 17% planning reserve margin factor. For every KW of load reduction that comes from EE, the Company does not need to plan for 1.17 KW of load serving capacity. Thus, witness Duff concluded that applying a 17% reserve margin factor to the avoided capacity associated with EE programs was logical and prudent from a planning standpoint. (Duff Rebuttal at 22.) Witness Duff also pointed out that witness Hinton's contention that the Company's proposal effectively increases what customers will pay for the avoided capacity cost benefits of the EE programs by increasing the avoided capacity rate above the approved rate is inaccurate. Witness Duff stated that this assertion ignored the Company's application to the reserve margin of the avoided capacity associated with EE savings and does not impact the avoided capacity rate applied to supply side resources in the resource plan, but rather reduces the magnitude of the supply side resources needed in the plan. (Duff Rebuttal at 26.)

Witness Duff confirmed that pre-dating the Company's merger with Duke Energy the Company had included a reserve margin adjustment to model EE cost-effectiveness. (Duff Rebuttal at 21.) He added that the inclusion continued after the 2012 merger. He reported that for all vintage years through 2014, DEP used the Strategist model to evaluate EE cost-effectiveness. Strategist included a variable for annual peak kW savings and a variable called deferred generation, which multiplied a reserve margin factor (of 1 + planned reserve margin) times the annual peak kW savings. Beginning with vintage year 2015, DEP began to use the DSMore tool for cost-effectiveness evaluations, but all the avoided cost inputs used for that vintage year continued to use the Strategist-based avoided costs, which included the adjustment for deferred generation described above. (Duff Rebuttal at 23.)

Although he acknowledged that DEP had not included the reserve margin since vintage year 2016, Witness Duff explained that the avoided capacity rates in that year's proceeding included a 1.20 PAF, which was also referred to as a 20% reserve margin adjustment. Thus, he concluded, it was no longer necessary for DEP to include its own reserve margin factor, so long as the 1.20 PAF was applied. Avoided capacity rates no longer contained the 1.20 PAF after the 2016 avoided cost proceeding, however, because the 1.20 PAF was lowered to 1.05. Instead of representing a 20% reserve margin, witness Duff explained, the PAF now accounts for a 5% forced outage rate. Thus, witness Duff concluded that because of that change in the PAF, and because DEP's IRP process treats EE peak load as a reduction to the load forecast, it is necessary to include the 17% reserve margin adjustment.

Witness Duff testified that even if the Commission determined that the PAF already included in the avoided capacity rates in this proceeding appropriately reflect a reserve margin, and not simply an effective forced outage rate, the Company should not be required to remove the 17% reserve margin adder. On the contrary, according to witness Duff, if the Commission determined that PAF represented a reserve margin, it would only account for a portion of the appropriate adjustment for the reserve margin associated with avoided capacity coming from EE programs. (Duff Rebuttal at 29.) In that case, witness Duff explained, an appropriate adjustment would be to only apply an 11.429% reserve margin adder to the avoided capacity to make the reduction reflect the 17% reserve margin after factoring in the 5% PAF already included in the Company's approved avoided capacity rate in Docket No. E-100, Sub 158. (Duff Rebuttal at 29.)

Witness Duff also disputed witness Hinton's assertion that customers will not see any benefit from this adjustment. Witness Duff noted that, although the 2018 IRP shows DEP's actual reserve margin as equal to more than 17% in the near term, that does not mean that there is no capacity value to building new EE resources several years before the in-service date of a new generating unit. Most EE measures in DEP's vintage 2021 have a longer life than six years, which is about the time that DEP's 2018 IRP includes a need for a new combustion turbine.

With respect to the Company's application of the reserve margin adder to the calculation of avoided capacity costs associated with EE programs, the Commission concludes that there is indeed a theoretical basis for such an adjustment, as noted by witness Hinton. (Hinton at 11.) The Commission notes that EE is treated as a load resource in the Company's IRP and agrees that with every kW of load reduction that comes from EE, the amount of load serving capacity for which the Company must plan is reduced by more than one kW. However, exactly what the reserve margin adjustment should be is not supported by substantial evidence in this docket. The Commission concludes that, for purposes of calculating the avoided capacity cost benefits for

DSM/EE programs, deviation from the approved methodology for calculating the avoided capacity costs that form the basis for rates paid to QFs is appropriate and that this matter should be studied by the Collaborative. Therefore, the Commission directs the parties to endeavor to identify an appropriate reserve margin adjustment to be used for EE programs in future proceedings.

In support of its conclusion, the Commission notes that application of a reserve margin factor is hardly novel. Although it appears that there was a gap of approximately four years in its inclusion, DEP has included a reserve margin adjustment since prior to 2012 in its determination of avoided cost value associated with the Company's EE programs. As evidenced by Duff Rebuttal Exhibit No. 1, DEP used a 14.5% minimum planned reserve margin adjustment as reflected in its then IRP for vintage year 2015 DSMORE evaluations, and a 1.2 PAF for vintage year 2016. At the time DEP stopped including the reserve margin adjustment for vintage 2016, DEP's avoided cost rates included a 1.20 PAF, which had been referred to as a 20% reserve margin adjustment in the past; thus, inclusion of the reserve margin was no longer necessary. In Docket No. E-100, Sub 148, the 2016 Biennial Avoided Cost proceeding, by order issued October 11, 2017, the PAF was revised from 1.20 to 1.05 and intended to account for only a 5% forced outage rate, instead of a 20% reserve margin. Although the Commission agrees that there is a theoretical basis for adding a reserve margin adjustment, it understands and agrees with the Public Staff's concerns about the Mechanism setting expectations on how the Company recovers its program costs, net lost revenues, and PPI. The Mechanism refers to the most recent avoided cost case as a guide to how the Company calculates if cost-effectiveness for programs. The Commission, however, must establish avoided cost rates based on the economic and regulatory circumstances present every two years. Therefore, avoided cost methodologies may change from time to time. The PAF is a good example of evolving avoided cost policies and methodologies in North Carolina. The Mechanism cannot foresee and account for all these potential future changes in avoided cost methodologies, and it does not make sense to wait for the Mechanism to expressly provide for such changes before the Commission can consider them in the context of a DSM/EE recovery proceeding. Therefore, to better enable the Commission and interested parties to address whether a proposed change is supported by the Mechanism and to account for interim changes in avoided methodologies driven by changing economic and regulatory circumstances, the Commission directs the Company in future DSM/EE rider proceedings to specifically address in its direct testimony whether it has altered its methodology for calculating avoided energy and capacity costs from the previous proceeding and, if so, identify how the most recent avoided cost proceeding justifies that change.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence for this finding of fact can be found in the testimony and exhibits of DEP witness Duff and Public Staff witness Hinton.

In his direct testimony, Public Staff witness Hinton opposed DEP's application of 100% summer seasonal allocation weighting to the avoided capacity benefits from the approximately 400 MW of DSM programs. Witness Hinton explained that DEP distinguished between "legacy" and "incremental" DSM programs in the evaluation of its DSM portfolio and cost-effectiveness. Legacy DSM is the level of DSM activation capability that was originally projected for the year 2021 in the 2018 IRP. Incremental means all activation capability that is above the MW projected in the year 2018 for year 2021. (Hinton at 16.) The Company values incremental measures and participation using the seasonal allocation weightings of 100% winter and 0% summer. (*Id.* at 4.)

With respect to seasonal allocation weightings, Witness Hinton agreed that the Company is winter planning, and he agreed to the Company's treatment of incremental DSM programs, but he opposed the Company's treatment of its legacy DSM programs. Because the Company is now winter planning, he concluded that the value of summer DSM is diminished for resource planning purposes in terms of a capacity resource at the expected time of peak and the dollar per kW associated with the demand reductions. Witness Hinton stated that this shift to winter planning, and the resulting recent change in the seasonal allocation factors, should "take precedence over the MW reductions" projected in the 2018 IRP. Therefore, witness Hinton recommended that the Company treat its legacy DSM as it had treated its incremental DSM. (Hinton at 18-19.)

Witness Hinton also supported his recommendation by testifying that his proposal would provide "added motivation" to the Company to find ways to reduce winter peak and predicted that "the allocation of seasonal capacity value to all of the DSM programs would appropriately direct the Company to emphasize programs that focus on reducing load during the winter season." (Hinton at 19.) He acknowledged, however, that DEP had already begun such an investigation aimed at reducing winter peak loads and had, prior to his testimony, filed modifications to its Residential Load Control Rider in Docket No. E-2, Sub 927, that would provide a winter-focused load control program. (*Id.*)

Witness Hinton also supported his recommendation that the Company not use the 100% seasonal allocation for its DSM programs by illustrating that the Company's highest cost for generation typically occurs in the winter, therefore activating DSM programs during that period was in the Company's best interest. He further indicated that activations of DEP's EnergyWise and other DSM programs (2015-2019) most often occurred in the winter. Witness Hinton did not intend to imply that DSM programs are not valuable, but instead to point out that their capacity value has changed relevant to the shifting of the seasonal weighting capacity needs from summer to winter. (Hinton at 28.) Thus, witness Hinton concluded that the Commission should deny DEP's proposal to give its legacy DSM/EE programs a 100% summer weighting under the current IRP winter planning scenario and require DEP to recalculate its cost-effectiveness and its PPI using 100% winter and 0% summer allocation of avoided capacity benefits. In making this recommendation, witness Hinton acknowledged that using the 0% summer allocation of avoided capacity benefits reduces the cost-effectiveness of the programs and overall cost-effectiveness of the portfolio. (Hinton at 29.)

Company witness Duff supported DEP's calculation of its avoided capacity costs using the seasonal allocation approved in the most recent avoided cost proceeding by first summarizing the agreement that DEP had reached with the Public Staff in Docket No. E-2, Sub 1145 (Sub 1145 Agreement). He testified that the Sub 1145 Agreement did not change the methodology by which the Company was to calculate avoided capacity costs and he confirmed that, consistent with the Sub 1145 Agreement, DEP had derived the avoided energy and avoided capacity using the underlying resource plan, production cost model, and cost inputs approved in the Company's most recent avoided cost proceeding, Docket No. E-100, Sub 158. (Duff Rebuttal at 8.)

Witness Duff disputed that the Sub 1145 Agreement changed how the Company calculated its avoided capacity costs to evaluate existing programs, already approved by the Commission, already part of the Company's existing portfolio of programs, and already factored into the Company's IRP. Witness Duff explained that to recognize the growing need for winter capacity and to encourage EE and DSM programs that will provide winter capacity savings, the Company made a change to its application of avoided capacity costs in this proceeding as compared to previous proceedings. Beginning with Vintage 2021, the Company voluntarily applied the 100% winter 0% summer seasonal allocation weightings approved in the most recent avoided cost proceeding to avoided capacity savings for all new incremental participation in EE programs and new incremental participation in DSM programs where the projected DSM summer peak capability exceeds the levels forecasted in the 2018 IRP. (*Id.* at 10-11.)

In addition to encouraging winter DSM, witness Duff believed that this approach aligned better with how new QFs receive capacity value from the last avoided cost proceeding. He pointed out that this approach is consistent with how new QF capacity is treated in the Commission's Notice of Decision and April 15, 2020 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* in Docket No. E-100, Sub 158 (Sub 158 Order). In the Sub 158 Order, the Commission acknowledged that the currently high solar penetrations in Duke's service territory, which are expected to continue into the future, will impact summer versus winter loads net of solar contribution differently than in the past. (Duff Rebuttal at 11.)

Witness Duff acknowledged that neither the Commission's Sub 158 Order nor the Sub 1145 Agreement expressly required adoption of the seasonal allocation for this cost-recovery proceeding, but he believed that the Company's application of the seasonal allocation factor to new and incremental DSM programs is appropriate here. He testified that the Company's treatment of legacy DSM programs is consistent with the treatment of existing QFs with respect to application of the Commission's determinations in its recent avoided cost proceeding. The Commission has previously concluded that the net benefits and financial incentives for DEP's DSM/EE programs are linked, although not identical, to the avoided cost rates DEP pays QFs for avoided energy and capacity. Witness Duff recalled that the Commission itself noted in its Sub 158 Order that seasonal allocation factors may change based on the then prevailing circumstances reviewed in the biennial cost proceedings. Therefore, witness Duff concluded that just as the Commission approved applying the seasonal allocation factors of 100% winter and 0% summer to future QF capacity in its Sub 158 Order, the Company applied the approved seasonal allocation factors to new and incremental DSM programs in this proceeding. As a corollary, just as the Commission did not retroactively apply its Sub 158 seasonal allocation factors to QFs that had previously established power purchase agreements at avoided cost rates that were approved based on past prevailing circumstances, the Company did not retroactively apply the seasonal allocations approved in Sub 158 to its legacy DSM programs. (*Id.* at 14.)

Moreover, witness Duff testified that the Commission's review of the Company's 2018 DSM/EE application supports the Company's treatment of its legacy DSM/EE in this proceeding. In that proceeding, Docket No. E-2, Sub 1174, the Public Staff recommended that the Commission assign zeros to capacity for legacy DSM programs until the first year of need as shown in the Company's IRP, based on the Commission's order in the then preceding avoided cost case, Docket No. E-100, Sub 148, and House Bill 589's recent amendments to N.C.G.S. § 62-156(b)(3). The

Company opposed this recommendation, arguing that the MW reductions of those programs were already included in the IRP and that its DSM programs had been established over several years and were a useful resource. Witness Duff indicated that he is not arguing that existing DSM capacity must be valued the same as existing QF capacity. Instead he argued that, just as it would be improper and contrary to the Commission's policies under the Public Utility Regulatory Policies Act (PURPA) to change the avoided capacity value for an existing QF, it would be likewise improper to change the avoided capacity value for an existing DSM resource (*Id.* at 14-15.)

Witness Duff also stated that DEP's legacy DSM programs were viewed from an IRP standpoint as a "dispatchable resource that is available for the entire fifteen-year planning period." (*Id.* at 16.) Specifically, he cited EnergyWise, which is available to dispatch into the evening hours when net load is still high due to diminished solar output, a circumstance known as the "duck curve." Conversely, he indicated that, if solar is lost due to midafternoon cloud cover, demand response can be used to make up for diminished irradiance. As an IRP resource, both existing demand response and existing solar resources are oriented toward summer peak demand reduction, helping to meet customer peak demand in the summer. The capacity value from these resources is at least in part the reason incremental resource decisions are now geared toward winter peak demand needs.

Witness Duff also noted that witness Hinton had disagreed in the recent DEC DSM/EE proceeding DSM/EE rider proceeding (Sub 1230) that DSM resources in legacy DSM programs are short-lived and, hence, each year's participation is new and incremental. Witness Hinton, however, had not continued with that argument in this proceeding. As witness Duff had explained in Sub 1230, although DEC and DEP use similar hardware on the residential side and similar contractual agreements on the non-residential side with respect to their legacy DSM programs, differences in cost-recovery mechanisms between the Companies result in DEC's using a one-year measure life and DEP's using a 25-year measure life. Witness Duff explained that regardless of the measure life for cost recovery purposes, legacy DSM resources have been built over time and the terms of implicit contract with customers more closely resemble the life of the load control switch than they do a one-year measure life. The Company's legacy DSM programs retain customers year after year, with only an approximate 1% annual net attrition rate. (Duff Rebuttal at 17.)

Witness Duff next disputed witness Hinton's contention that the capacity value of the legacy summer DSM resources has changed because of changes in the Company's system lambda. As witness Duff explained, changes in the Company's system lambdas could just as easily be explained by the milder 2017-19 summers when compared to the summer of 2016, where summer DSM programs were activated a significant number of times. Witness Duff stated that his cursory examination of historical temperatures indicated that the summer of 2016 was much hotter than normal. Moreover, the full value of a summer DSM resource occurs during extreme weather days where the ability to dispatch a summer DSM program provides peak load reduction less expensive to customers than starting up and running more expensive peaking generation. (Duff Rebuttal at 19.)

Witness Duff also stated that the Public Staff's recommended approach was not necessary to better encourage the Company to promote winter-focused DSM and EE programs. He did not understand how an approach that devalued the Company's existing, approved summer resource, which is relied upon in system planning, in any way encourages more winter capacity savings. The recognition of full capacity value for an existing Summer legacy resource does not influence the emphasis the Company places on promoting new participation and savings in a winter resource. In support, witness Duff cited the Company's recently filed request for approval of a winter-focused modification to its Residential Load Control in Docket No. E-2, Sub 927. (Duff Rebuttal at 19-20.)

Finally, witness Duff contested Public Staff witness Hinton's contention that applying the seasonal allocation factor to legacy DSM programs should not matter because the programs still project to be cost-effective afterward. He cautioned that with witness Hinton's recommendation, the avoided costs associated with the legacy resource must come from avoided transmission and distribution (T&D) value. T&D rates are required by the Commission to be studied and updated prior to 2022. Given this uncertainty, witness Duff believed that the Commission should decline to adopt witness Hinton's recommendation because it might result in the programs no longer being cost-effective if there is a decline in T&D values.

The Company and the Public Staff agree that the seasonal allocation weightings approved by the Commission in the most recent avoided cost proceeding in Docket No. E-100, Sub 158 should be applied to new and incremental DSM programs; therefore, the issue before the Commission is whether it should approve the Public Staff's recommendation to extend the newly-approved seasonal allocation weightings to pre-existing legacy DSM capacity. The record before the Commission, however, does not support approval of the Public Staff's recommendation.

The Commission agrees that the Company's distinction between legacy DSM (the capacity resource that has been built from historic and planned DSM programs or the amount of DSM capacity in the Company's 2018 IRP forecast as a load serving resource) and incremental or new DSM capacity (the capacity resources that are built from new participation in DSM programs that were not factored into the Company's IRP as a load serving resource) is appropriate for purposes of this proceeding. The Commission further concludes that DEP's legacy DSM programs should not be treated as new or incremental. DEP's legacy DSM programs are viewed as a dispatchable resource that is available for the entire 15-year IRP planning horizon and the DSM programs in the DSM/EE IRP block are "expected to continue for the foreseeable future." (Duff Rebuttal at 18.) As an IRP resource, both existing demand response and existing solar QF resources are oriented toward summer peak demand reduction, helping to meet customer peak demand in the summer. The capacity value from these resources is at least in part why incremental resource decisions are now geared toward winter peak demand needs. This does not mean that the existing summer-oriented resources have less value, but recognizes that *incremental* additions to those resources, whether they are solar or DSM, would have diminished incremental value.

As noted by DEP witness Duff, the Commission previously reviewed an almost identical issue in the DEC DSM/EE rider proceeding. In that proceeding, DEC argued in its brief and proposed order that the Public Staff's recommendation to extend the seasonal allocation weightings beyond new and incremental DSM capacity to its existing, approved legacy DSM simply ignored the value of that existing, approved legacy DSM. DEC noted that the Public Staff's recommendation relied in part upon the fact that DEC's DSM measures had only a one-year measure life, meaning that all DSM capacity was "incremental" and that the Mechanism did not provide for application of seasonal allocation weightings in DSM/EE cost recovery proceedings. The Public Staff has not continued with those arguments in this proceeding, but it still argues that applying the seasonal allocations to all existing DSM would motivate the Company to promote winter capacity focused DSM and EE programs.

The Commission recognizes that the Company voluntarily undertook applying the seasonal allocations for new incremental programs and participation in this proceeding to encourage the development and specific promotion of EE and DSM programs that provide winter capacity savings. There is no evidence to support, however, the Public Staff's claim that additionally applying a 0% seasonal allocation factor to *an existing Summer legacy* resource somehow better encourages the Company's development or promotion of new participation in winter focused programs. In fact, the Company's recent filing for approval of its winter-focused modification to its Residential Service Load Control in Docket No. E-2, Sub 927, belies the Public Staff's claim. In sum, the Commission does not see any nexus between applying 0% seasonal allocation factor to an existing, approved summer DSM resource and motivating the Company to pursue more winter-focused DSM programs. Nor does the Commission believe it must adopt the Public Staff's position that the seasonal allocational weightings must be applied to *both* new and incremental DSM and EE participation and resources and legacy summer resources to better encourage the Company to promote winter-focused DSM and EE, when the Company is already doing so.

The Commission is also not persuaded that DEP's legacy summer DSM programs should have the 0% seasonal allocation weighting because DEP has had fewer activations of them in the past four years. As witness Duff testified, that decrease in activations could be explained by the milder 2017-19 summers when compared to the summer of 2016, where summer DSM programs were activated a significant number of times. Witness Duff's cursory examination of historical temperatures indicated that the summer of 2016 was much hotter than normal. No party contested witness Duff's testimony in this regard. Moreover, the full value of a summer DSM resource occurs during extreme weather days where the ability to dispatch a summer DSM program provides peak load reduction that is less expensive to customers than starting up and running a more expensive peaking generation. In short, the value of the summer capacity is having it available, and it should not be valued with a 0% seasonal allocation weighting.

The Commission is additionally concerned that the Public Staff's approach to legacy DSM programs makes them less cost-effective. Although the Public Staff's approach does not result in the Company's legacy DSM programs not being cost-effective for Vintage 2021, the approach does have potential adverse long-term impacts on this important legacy summer resource. With 0% of the avoided capacity value being recognized under the Public Staff's approach, most of the avoided costs associated with this legacy resource come from avoided T&D value. If T&D costs decrease, it would further imperil the cost-effectiveness of these programs. Given that uncertainty, the Public Staff's approach jeopardizes the cost-effectiveness of these programs, and thereby potentially jeopardizes their continuation.

Finally, the Commission concludes that legacy DSM programs are a desirable resource that is not only encouraged but mandated by the State. Senate Bill 3 was passed in August 2007 "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS)." N.C.G.S. § 62-2(10). The stated goals of the legislation are to diversify the resources used to reliably meet the energy needs of consumers in the State, provide greater energy security through the use of indigenous energy resources available within the State, encourage private investment in renewable energy and EE, and provide improved air quality and other benefits to energy consumers and citizens of the State. Id. To this end, Senate Bill 3 provides that electric utilities "shall implement demand-side management and energy efficiency measures and use supply-side resources to establish the least cost mix of demand reduction and generation measures that meet the electricity needs of its customers." *See* N.C.G.S. § 62-133.9. This legislation provides that the utilities shall be compensated for their DSM/EE efforts and allows incentives to be awarded, including rewards based upon shared savings and avoided costs achieved by DSM/EE measures. *See* N.C.G.S. § 62-133.9. Therefore, it is inconsistent with North Carolina policy to reduce the Company's incentive based on the Public Staff's method. The Commission approves the Company's seasonal allocation methodology.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-22

The evidence for these findings of fact can be found in the direct testimony and exhibits of DEP witness Listebarger and the direct testimony and exhibits of Public Staff witness Maness.

DEP witness Listebarger calculated proposed North Carolina retail NLR in the amount of $38,111,736 and a PPI in the amount of $26,905,577 for the EMF component of the total DSM/EE rider, as reflected in Listebarger Exhibit 2, page 6, and North Carolina retail NLR of $34,768,785 and a PPI of $21,191,901 for the forward-looking, or prospective component of the total rider, as reflected on Listebarger Exhibit 2, page 3. Witness Listebarger testified that, for purposes of the EMF component of its DSM/EE rider, DEP's reasonable and prudent North Carolina retail test period costs and incentives, consisting of its amortized O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, are $176,818,282. Witness Listebarger's testimony and exhibits also indicated that the amount of test period DSM/EE rider revenues and miscellaneous adjustments to take into consideration in determining the test period DSM/EE under- or over-recovery is $172,654,182. Therefore, the test period revenue requirement, as reduced by the test period revenues collected and miscellaneous adjustments, is $4,164,100, which is the test period under-collection that is appropriate to use as the DSM/EE EMF revenue requirement in this proceeding. (Listebarger at 7.)

Witness Listebarger also calculated DEP's estimate of its North Carolina retail DSM/EE program rate period amounts, consisting of its amortized O&M costs, depreciation, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, as $169,661,531. (Listebarger at 8.) The $169,661,531 revenue requirement includes, (1) $22,456,410 for anticipated rate period program expenses; (2) amortizations and carrying costs associated with deferred prior period costs totaling $74,404,105, (3) recovery of DSDR depreciation and capital costs totaling $16,840,330, (4) net lot revenues for the rate period totaling

$34,768,785 for vintage years 2018 through 2021, and (5) PPI totaling $21,191,901 associated with vintage years 2012 through 2021. (Listebarger at 8-9.)

According to the exhibits of DEP witness Listebarger, after assignment or allocation to customer classes in accordance with N.C.G.S. § 62-133.9, Commission Rule R8-69, and the Commission Orders in Docket No. E-2, Sub 931, the revenue requirements for each class, excluding NCRF, are as follows:

DSM/EE PROSPECTIVE COMPONENT:	
Residential	$101,854,909
General Service EE	60,865,888
General Service DSM	6,600,295
Lighting	340,439
Total	$169,661,531

DSM/EE EMF:	
Residential	$1,988,123
General Service EE	3,131,509
General Service DSM	(931,458)
Lighting	(24,075)
Total	$4,164,100

(Listebarger Exhibit 2, p. 1 of 7, p.2 of 7, p. 4 of 7 and p.5 of 7)

Witness Listebarger's exhibits also set forth the North Carolina retail class level kWh sales that DEP believes are appropriate and reasonable for use in determining the DSM/EE and DSM/EE EMF billing factors in this proceeding. She adjusted the kWh sales to exclude estimated sales to customers who have opted out of participation in DEP's DSM/EE programs. (Listebarger at 15-16.) Based on her exhibits, the appropriate and reasonable North Carolina retail class level kilowatt-hour (kWh) sales for use in determining the DSM/EE and DSM/EE EMF billing factors in this proceeding are:

Rate Class	kWh Sales
Residential	15,893,328,062
General Service EE	9,132,663,985
General Service DSM	9,064,020,676
Lighting	356,925,937

(Listebarger Exhibit 2, p.1-2 of 7.)

Witness Listebarger testified that the proposed DSM/EE rates recover costs forwarded to be incurred from January 1, 2021 through December 31, 2021. The DSM/EE EMF is a true-up mechanism recognizing costs and recoveries for the test period of January 1, 2019 through December 31, 2019. She further testified that DEP proposed the following total DSM/EE billing factors, excluding NCRF: 0.654 cents per kWh for the Residential class; 0.700 cents per kWh for the EE component of the General Service classes; 0.063 cents per kWh for the DSM component of the General Service classes, and 0.088 cents per kWh for the Lighting class. Witness Listebarger next testified that, including the NCRF, the appropriate DSM/EE billing factors are 0.655 cents per kWh for the Residential class and 0.701 cents per kWh for the EE component of the General Service classes. The DSM/EE billing factors for the DSM component of the General Service classes and the Lighting classes do not change when the NCRF is included. (Listebarger at 19.)

Witness Listebarger also testified that DEP had incorporated a placeholder for the return of excess deferred income taxes (EDIT) into Rider 11 to mitigate potential overcollection with respect to the Company's DSM/EE Rider by including a reduction of $5 million to Year 2020 lost revenues collected from Vintage 2017, Vintage 2018, Vintage 2019, and Vintage 2020. She noted that this would be trued up to the actual EDIT impact on the lost revenue in the next DSM/EE rider filing after an Order is issued in DEP's pending base rate case, Docket No. E-2, Sub 1219. (Listebarger at 14.)

Public Staff witness Maness indicated that the focus of the Public Staff's investigation of DEP's filing in this proceeding was whether the proposed DSM/EE rider was calculated in accordance with the Mechanism and otherwise adhered to sound ratemaking concepts and principles. (Maness at 11.) The Public Staff's investigation included a review of the Company's current filing and relevant prior Commission proceedings and orders, and workpapers and source documentation used by the Company to develop the proposed billing rates (including the selection and review of a sample of source documentation for test period costs included by the Company for recovery). (*Id.* at 11-12.)

Excepting the adjustments recommended by Public Staff witnesses Hinton and Williamson regarding removal of the reserve margin adder and including an adjustment for seasonal allocation, witness Maness testified that he believed that the Company has calculated its proposed prospective DSM/EE and DSM/EE EMF billing factors in a manner consistent with N.C.G.S. § 62-133.9, Commission Rule R8-69, and the Mechanism. (*Id.* at 12.)

Other Adjustments to Rate Calculations

Witness Maness testified that Public Staff witnesses Williamson and Hinton have each filed testimony and exhibits in this proceeding that recommend certain changes to the calculations of avoided cost savings for estimated vintage 2021 DSM/EE participation. The first recommended change involves the elimination of a reserve margin that the Company has added to avoided capacity benefits for vintage 2021 EE measures and the second involved the seasonal allocation weightings. (Maness at 13.) He also noted that witness Williamson had filed testimony addressing other factors in this proceeding, but they did not necessitate an adjustment to the Company's billing factor calculations. (Maness at 15.)

Witness Maness concluded that other than these issues, the Public Staff found no errors or other issues necessitating an adjustment to DEP's proposed billing factors. As discussed above, Public Staff witness Williamson filed testimony in this proceeding discussing several EM&V-related topics and issues related to the Company's filing. Aside from the items discussed above, none of these topics and issues necessitates an adjustment to the Company's billing factor calculations.

Based on the foregoing, with the exception of the Company's proposed 17% reserve margin adder as discussed above, the adjustments are approved by the Commission. The Commission concludes that DEP has complied with N.C.G.S. § 62-133.9, Commission Rule R8-69, and the Commission's orders in Docket Nos. E-2, Sub 931 and Sub 1145, regarding calculating costs and utility incentives for the test and rate periods at issue in this proceeding.

Therefore, the Commission concludes that for purposes of the DSM/EE EMF billing rates to be set in this proceeding, DEP's reasonable and prudent North Carolina retail test period costs and incentives, consisting of its amortized DSM/EE O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, are $176,818,282 (excluding the NCRF). The reasonable and appropriate amount of test period DSM/EE rider revenues and adjustments to take into consideration in determining the test year and prospective period DSM/EE under- or over-recovery is $172,654,182(excluding the NCRF). Therefore, the aggregate DSM/EE under-recovery for purposes of this proceeding is $4,161,100. (Listebarger at 7.).

For purposes of the DSM/EE rider to be set in this proceeding, and subject to review in DEP's future DSM/EE rider proceedings, the Commission concludes that DEP's reasonable and appropriate estimate of its North Carolina retail DSM/EE program rate period amounts, consisting of its amortized O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI is $169,481,478 (excluding the NCRF) which is the appropriate amount to use to develop the DSM/EE revenue requirement.

For the revenue requirements per class, the Commission concludes that after assignment or allocation to customer classes in accordance with N.C.G.S. § 62-133.9, Commission Rule R8-69, and the orders in Docket No. E-2, Sub 931, the revenue requirements for each class, excluding NCRF, are as follows:

DSM/EE PROSPECTIVE COMPONENT:	
Residential	$101,755,267
General Service EE	60,785,477
General Service DSM	6,600,295
Lighting	340,439
Total	$169,481,478

DSM/EE EMF:	
Residential	$1,988,123
General Service EE	3,131,509
General Service DSM	(931,458)
Lighting	(24,075)
Total	$4,164,100

Furthermore, the Commission finds that the appropriate and reasonable North Carolina retail class level kWh sales for use in determining the DSM/EE and DSM/EE EMF billing factors in this proceeding are as follows: Residential class - 15,893,328,062; General Service class

EE - 9,132,663,985; General Service class DSM - 9,064,020,676, –and Lighting class - 356,925,937. (Listebarger Exhibit 2, pages 1 and 2 of 7.)

Based on the testimony and exhibits of witnesses Listebarger and Evans, the testimony and exhibits of witness Maness, and the entire record in this proceeding, the Commission finds and concludes that the DSM/EE EMF billing factors as proposed by DEP and the Public Staff are appropriate and the forward-looking DSM/EE rates to be charged during the rate period for the Residential, General Service, and Lighting rate schedules are as follows:

DSM/EE PROSPECTIVE COMPONENT (¢/kWh):		
	Excluding NCRF	Including NCRF
Residential	0.640	0.641
General Service EE	0.666	0.667
General Service DSM	0.073	0.073
Lighting	0.095	0.095

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 23-24

The evidence for these findings of fact can be found in the testimony of NC Justice Center, et al. witness Bradley-Wright, Public Staff witness Williamson, and DEP witness Evans.

Company witness Evans reported that during vintage 2019, DEP's DSM/EE programs delivered over 409 million kWh of energy savings and close to 351 MW of capacity savings, which produced a net present value of avoided cost savings of close to $215 million. (Evans Direct at 21.) Three residential programs—Residential Energy Efficient Appliances and Devices Program; Residential Multi-Family Energy Efficiency Program; and the Residential New Construction Program—did not achieve energy savings in excess of those forecasted for 2019. He noted that the primary drivers for the underperformance of these programs are changes in the estimated impacts and the mix of program measures. Additionally, three non-residential programs—Non-Residential Smart $aver Performance Incentive; the Small Business Energy Saver; and EnergyWise for Business program—also failed to meet energy savings expectations–. (*Id.* at 22-23.)

Witness Evans also described the Collaborative's activities since the previous DSM/EE cost recovery proceeding. He noted that in the DSM/EE cost recovery rider proceedings in 2019, the Commission ordered that DEP and the Collaborative participants should give attention to the five directives stated by the Commission. Witness Evans quoted these five directives from the Commission's order as follows:

- DEP and the Collaborative participants should continue working to ensure that all interested persons have a reasonable and timely opportunity to contribute ideas for consideration, especially with respect to proposals for new programs or modifications to existing programs;

- The Collaborative should continue to place emphasis on developing EE programs to assist low-income customers in saving energy, and in developing EE programs that target savings in new construction, and especially in multi-family housing and manufactured housing.
- The forecasted decline in DEP's DSM/EE savings in 2020 is a matter of concern. Consequently, the Collaborative should examine the reasons for the forecasted decline and explore options for preventing or correcting a decline in future DSM/EE savings.
- The Collaborative should study the development of a standard annual reporting protocol. In addition, the Commission concludes that it would be helpful for DEP to include in its annual DSM/EE application a table that shows DEP's test period DSM/EE cost and savings, and that shows the same information for the previous five years.
- With respect to the recommendation by the NC Justice Center, et al., DEP is pursuing and has discussed with the Collaborative an expansion of the Neighborhood Energy Saver to include weatherization measures. Furthermore, the Company intends to file proposed modifications to the program to be effective in early 2020. If the modifications filed by DEP in 2020 do not satisfy the weatherization changes sought by NC Justice Center, DEP should continue to discuss the adoption of an Income-Qualified Weatherization program comparable to DEC's.

(Evans Direct at 8-9.) Witness Evans reported that the Collaborative meets every other month in person, or, more recently due to the COVID-19 pandemic, via video conferencing, and discusses on separate conference calls individual topics that cannot be explored adequately during the meetings. The Collaborative spends time exploring avenues for expanding low-income programs and for increasing the participation of low-income customers in all available programs. Witness Evans also described how the Collaborative met every other month to explore opportunities for expanding program impacts and participation. In late 2019, members compiled a list of potential programs to research and propose to the Company during 2020, and the Company is investigating these suggestions. The Collaborative has struggled, according to witness Evans, however, to offer program suggestions that would make up for the reductions that the Company anticipates because the forecasted decline is driven by a combination of falling avoided costs, higher federal equipment standards, and increased market penetration of energy efficiency measures, all factors outside of the Collaborative's sphere of influence. (*Id.* at 13.)

Witness Evans did confirm that the Collaborative studied the development of a standard annual reporting protocol and the Company included in its application a table that shows DEP's test period DSM/EE costs and savings and the same information for the previous five years. This was attached as Evans Exhibit 12. (*Id.* at 13.)

Witness Evans also testified that, due to the pandemic, the Neighborhood Energy Saver had been suspended. However, witness Evans was confident that many low-income customers will receive enhanced weatherization services through this program. The Collaborative continues to discuss adopting an income-qualified weatherization program in DEP. (*Id.* at 14.)

Witness Evans also described how opt-outs by qualifying non-residential customers have impacted DEP's overall non-residential participation and the associated impacts. For Vintage 2019, DEP had 5,868 eligible customer accounts opt out of participating in DEP's non-residential portfolio of EE programs and 5,759 eligible customers accounts opt out of participating in DEP's non-residential portfolio of DSM programs. This represented an increase for opt-outs for both EE and DSM programs from 2018. The Company, however, is continuing its efforts to attract program participants from opt-out customers. It does so by evaluating and revising its non-residential programs to accommodate new technologies, eliminating program gaps, removing barriers to participation, and making programs more attractive. (*Id.* at 27.)

NC Justice Center *et al.* witness Bradley-Wright testified that DEP's efficiency savings were lower in 2019 than they had been in the previous two years. In 2019, DEP delivered 353.2 gigawatt-hours (GWh) of efficiency savings at the meter, equal to 0.78% of the previous year's retail sales. Witness Bradley-Wright noted that DEP still had not reached the 1% annual savings target and continues to lag DEC, but he nevertheless commended DEP for delivering savings to its customers, particularly when avoided costs are declining and changes have occurred in DEP's efficiency baselines. (*Id.* at 7.)

Witness Bradley-Wright noted that in 2019, approximately 56% of the non-residential load opted out of DEP's energy efficiency rider. Opt-outs lead to uncertainty about how much efficiency savings are being captured by customers that opt out. (*Id.* at 9.)

With respect to low-income efficiency savings, witness Bradley-Wright testified that DEP's Neighborhood Energy Saver program increased its savings modestly from 2018 to 2019. He noted that the Company also captured savings from its Pay for Performance low income pilot program. Continued growth of efficiency savings for low-income customers has been a consistent focus at the Collaborative and DEP has shown a willingness to engage on this issue. However, the impact of programs that aim to specifically serve low-income customers at DEP lags behind DEC's programs. He recommended that DEP try to match the recent DEC performance. (*Id.* at 10, 19-20.)

Witness Bradley-Wright further testified that DEP has not achieved the 1% target annual savings threshold, even though DEC has exceeded this target in 2017 and 2018 and nearly reached it in 2019. He acknowledged, however, that the COVID-19 pandemic creates additional uncertainty and warrants additional action. In witness Bradley-Wright's opinion, DEP has not fully provided an explanation for its decline in projected energy savings, as requested in DEP's previous rider proceeding. He indicated that Witness Evans discussed falling avoided cost, higher federal equipment standards and increased market penetration of energy efficiency measures as drivers of declining savings, but he recommended that the Company provide updated information and options for preventing or correcting this decline. Witness Bradley-Wright urged the Company to work on identifying these options in the Collaborative and to provide written reports on status. (*Id.* at 13.)

Witness Bradley-Wright also recommended that the Commission should direct DEP to:

- Explain forecasted declines, when applicable, and show what steps are being taken to prevent them in future filings.
- Provide a detailed plan in subsequent DSM/EE Rider filings for how it could achieve the 1% annual savings in any year projections fall short.
- Work with the Collaborative to annually prepare a corresponding report aimed at assisting DEP to prevent or correct future savings declines and meet the 1% annual savings levels.

(*Id.* at 17-18.)

Witness Bradley-Wright also discussed achieving greater efficiency savings for low-income customers. He contrasted DEC's success with DEP's, indicating that DEC achieved greater success for its low-income customers in 2019. DEC, he indicated, spends more on low-income programs than DEP. (*Id.* at 19.) Witness Bradley-Wright urged DEP to expand its programs for low-income customers and noted that if the Commission approves the partial settlement agreement and stipulation in the pending DEP rate case, there will be additional low-income efficiency programs for DEP and members of the Collaborative to consider. (*Id.* at 20.) With respect to low-income customer programs, Witness Bradley-Wright recommended that the Commission:

- Express support for DEP pursuing higher levels of efficiency savings for low-income customers
- Direct DEP to provide a plan in its next DSM/EE rider showing how it could ramp up low-income efficiency savings over the next three to five years.

(*Id.* at 24.)

Witness Bradley-Wright referred to the COVID-19 pandemic and its implications for energy efficiency as well. He stated that DEP has not developed an overarching plan to adapt its energy efficiency approach to the COVID-19 era. Discussions about the relationship between COVID-19 and DEP's energy efficiency programs are in the early states at the Collaborative. Witness Bradley-Wright referred to the Michigan Public Service Commission's response to the COVID-19 pandemic and its resulting direction to staff to identify: (i) potential impacts on meeting energy and demand savings targets and ways to mitigate such impacts and ensure program continuity and (ii) best practices for continuing to serve low- to moderate-income households, including those impacted directly by COVID-19. (*Id.* at 27-28.)

Witness Bradley-Wright also updated the Commission on the Collaborative's work on the five directives. He agreed that the Collaborative had continued to meet bi-monthly, but he indicated that the Collaborative had more work to do on the five directives. Collaborative members have raised several new program concepts that were captured in the Portfolio Level Opportunities and Challenges Summary Report. He further reported that DEP continues to work with the Collaborative to provide useful topline, trend, and comparative data through its program performance reporting to the Collaborative. He recommended that DEP continue to work with the Collaborative to refine its data reporting. He also recommended that the Collaborative establish timelines and project schedules and provide written status reports on them.

DEP witness Evans responded to witness Bradley-Wright's concern regarding DEP's projection of savings below 1% of prior retail sales. He explained that the 1% target is an aspirational goal, and that other metrics exist to evaluate portfolio performance, such as demand reductions, ratio of costs to benefits, or differentiating between savings across customer segments. DEP remains committed to achieving all cost-effective energy savings up to and exceeding 1% when possible, but it is also focused on maximizing the performance of individual programs year over year and striving to achieve the most benefits for customers. (Evans Rebuttal at 11-12.)

Witness Evans disagreed that the Collaborative must prepare written reports and develop project schedules and timelines to be effective, although he welcomed any report a member submitted or prepared to the Company for the Collaborative's consideration. To be mindful of the members' time and other professional duties, however, he noted that the Company avoided asking Collaborative members to perform unnecessarily burdensome tasks. (Evans Rebuttal at 12.)

In response to witness Bradley-Wright's call for a specific DSM-EE COVID-19 strategy, witness Evans noted that Duke Energy Corporation has launched a corporate strategy to address the needs of customers in the aftermath of the pandemic; thus, DEP does not need to file a COVID-19 specific plan. He acknowledged that the Company had to suspend some programs temporarily, almost all programs have now resumed with additional safety protocols. Only two have not resumed, due to their increased risk to customers and contractors – Neighborhood Energy Saver and Multifamily Direct Install. The Company is working on resuming these programs, however, once risks can be mitigated. Finally, witness Evans testified that the Company has not adjusted its projections based on staffing and achievable energy savings potential in the market, neither of which has substantially changed as a result of the COVID-19 pandemic.

In its post-hearing Brief, NC Justice Center, *et al.*, stated its concern that DEP's EE savings were lower in 2019 than in the previous two years, and that DEP has repeatedly not achieved the agreed upon annual-energy savings target of 1% of prior year retail sales, reaching only 0.78% in 2019. NC Justice Center, *et al.*, stated that this represents a decline from 2018, when DEP reported annual savings of 0.88% of prior year retail sales, and that, in contrast, DEP's sister utility, DEC, achieved 794.9 GWh of savings in 2019, equal to savings of 0.98% of prior-year retail sales. NC Justice Center, *et al.*, stated, however, that the Company's DSM/EE programs continue to provide strong value for its customers.

Further, NC Justice Center, *et al.*, stated that DEP is forecasting only a modest increase in savings to 0.85% in 2021. It reiterated the testimony of witness Bradley-Wright on several points, including his concern about DEP's forecast of declining energy savings. In that regard, it recommended several steps to improve DEP's performance, and stated that it continues to promote the establishment of new energy savings targets.

In addition, NC Justice Center, *et al.*, discussed several options that it contends DEP can pursue to reverse what NC Justice Center, *et al.*, views as a lackluster performance in serving the EE needs of low income customers.

Moreover, NC Justice Center, *et al.*, stated that it is encouraged by progress made within the Collaborative during the last year, and that DEP has worked with stakeholders to shape priorities for the year, and the agendas for individual Collaborative meetings. However, it stated that it continues to believe that Commission engagement and enhanced accountability of the Collaborative will be important to improve upon that progress in the future. Finally, it reiterated the other recommendations made by witness Bradley-Wright in his testimony.

The Commission has fully reviewed the issues raised and recommendations made by NC Justice Center, *et al.*, witness Bradley-Wright and concludes the following:

(1) The current and forecasted decline in DEP's DSM/EE savings in 2021 is a matter of concern. Consequently, the Collaborative should examine the reasons for the forecasted decline and explore options for preventing or correcting a decline in future DSM/EE savings.

(2) The Collaborative should continue to emphasize developing EE programs to assist low income customers in saving energy and reducing their energy burdens.

(3) Due to the uncertainty and risks posed by the COVID-19 pandemic, the Commission is unwilling to direct DEP to file a plan to increase efficiency assistance; however, the Commission urges DEP to continue its efforts to benefit its customers in the form of reduced energy burdens and report on those efforts in its 2021 DSM/EE rider application.

(4) In lieu of a report from the Collaborative, the Company should continue reporting on Collaborative activities in its testimony filed in these proceedings. Other parties are encouraged to address Collaborative activities through future interventions.

IT IS, THEREFORE, ORDERED as follows:

1. That the appropriate DSM/EE EMF billing factors, excluding NCRF, for the Residential, General Service, and Lighting rate classes are: 0.013 cents per kWh for the Residential class; 0.0034 cents per kWh for the EE component of General Service classes; (0.010) cents per kWh for the DSM component of General Service classes; and (0.007) cents per kWh for the Lighting class. The factors do not change with the NCRF included;

2. That the appropriate forward-looking DSM/EE rates to be charged by DEP during the rate period for the Residential, General Service, and Lighting rate classes (excluding NCRF) are: 0.640 cents per kWh for the Residential class; 0.666 cents per kWh for the EE component of General Service classes; 0.073 cents per kWh for the DSM component of General Service classes; and 0.095 cents per kWh for the Lighting class;

3. That the appropriate total DSM/EE annual riders including the DSM/EE rate and the DSM/EE EMF rate (including NCRF) for the Residential, General Service, and Lighting rate classes are increments of 0.654 cents per kWh for the Residential class, 0.701 cents per kWh for the EE portion of the General Service classes, 0.063 cents per kWh for the DSM portion of the General Service classes, and 0.088 cents per kWh for the Lighting class;

4. That DEP shall file appropriate rate schedules and riders with the Commission to implement these adjustments as soon as practicable. Such rates are to be effective for service rendered on or after January 1, 2021;

5. That DEP shall work with the Public Staff to prepare a joint proposed Notice to Customers giving notice of rate changes ordered by the Commission herein, and DEP shall file such proposed notice for Commission approval as soon as practicable;

6. That the Public Staff shall continue to observe DSDR and the development of the Grid Improvement Plan and report on any overlap of the two, as necessary;

7. That DEP shall continue to leverage its Collaborative to discuss the EM&V issues and program design issues raised in the testimony of NC Justice Center, *et al.* witness Bradley-Wright as discussed herein and the results of these discussions shall be reported to the Commission in the Company's 2021 DSM/EE rider filing;

8. That DEP and the Collaborative shall discuss the issue of an appropriate way to reflect the full avoided capacity of its EE programs including avoided reserve capacity and present those findings to the Commission in its next DSM/EE rider proceeding; and

9. That continuing in 2021, the combined DEC/DEP Collaborative shall meet every other month.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of December, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Joann R. Snyder, Deputy Clerk

DOCKET NO. E-2, SUB 1253

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 Purchased from Joint Power Agency Pursuant to N.C. Gen. Stat. § 62-133.14 and Rule R8-70	)))))	ORDER APPROVING JOINT AGENCY ASSET RIDER

HEARD: Tuesday, September 15, 2020, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina (Public Witness Hearing, Hearing Examiner Heather Fennell, Presiding)

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

APPEARANCES:

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For the Using and Consuming Public:

Gina Holt, Staff Attorney, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

BY THE COMMISSION: On June 9, 2020, 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 prefiled testimony, DEP sought approval of the proposed rider, which incorporated the Company's proposed adjustments in its North Carolina retail rates.

On June 29, 2020, 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 June 17, 2020, Carolina Utility Customers Association, Inc. filed its petition to intervene. The Commission granted the petition on June 18, 2020. On August 25, 2020, Carolina Industrial Group for Fair Utility Rates II filed its petition to intervene. The Commission granted the petition on August 25, 2020. The intervention and participation by the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

To assist in preventing the spread of COVID-19, on August 7, 2020, the Commission issued an order scheduling a remote hearing for expert witness testimony and requiring parties to file written statements of consent by September 1, 2020. All parties filed statements of consent.

On August 28, 2020, the Public Staff filed the affidavit of Michael C. Maness – Director of the Accounting Division of the Public Staff.

No other party prefiled testimony in this docket.

On September 8, 2020, DEP and the Public Staff filed a Joint Motion to Excuse All Witnesses from appearing at the September 15, 2020, expert witness hearing in this proceeding. The Commission granted this motion on September 10, 2020, cancelled the expert witness hearing, and required that proposed orders be filed by October 16, 2020. The Order also received the witnesses' prefiled testimony, exhibits, and affidavits into the record. The Commission's Order also excused the appearance of counsel.

On September 14, 2020, DEP filed its affidavits of publication for the public notice, as required by the June 29, 2020 Order.

This matter came on for the public witness hearing as scheduled on September 15, 2020. No public witnesses appeared.

On October 16, 2020, DEP and the Public Staff filed a Joint Proposed Order.

Based upon the foregoing, DEP's verified application, the testimony, exhibits, and affidavits that were received into the record prior to 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.G.S. § 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. Section 62-133.14 allows DEP 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, 2019 through December 31, 2019. 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 or a "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 2020 through November 2021, and a Joint Agency Asset RRF component that accomplishes the true-up of costs incurred through the test year ended December 31, 2019.

6. In its application and testimony in this proceeding, DEP requested a total of $154.703 million for the prospective component of its North Carolina retail revenue requirement, for the period December 1, 2020, through November 30, 2021, 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 $8.488 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.G.S. § 62-133.14(b)(1).

8. DEP requested an additional $20.660 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, 2020, to November 30, 2021, to be $69.088 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 $0.201 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 $154.703 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 effective March 16, 2018, in DEP's general rate case under 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 $27.572 million in its application and testimony in this proceeding through the Joint Agency Asset RRF component of its North Carolina retail revenue requirement charged during the period December 1, 2020, through November 30, 2021, related to the overrecovery of financing and non-fuel operating costs experienced through the test year ended December 31, 2019. The Commission finds the actual costs and credits underlying this true-up amount to be reasonable and prudent for purposes of this proceeding, and return of this amount to be reasonable and appropriate.

13. Under N.C.G.S. § 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 most recent 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	0.00459	(0.00080)	0.00379
Small General Service	SGS, SGS-TOUE	0.00559	(0.00198)	0.00361
Medium General Service	CH-TOUE, CSE, CSG	0.00439	(0.00170)	0.00269
Seasonal and Intermittent Service	SI	0.00468	(0.00402)	0.00066
Traffic Signal Service	TSS, TFS	0.00255	(0.00061)	0.00194
Outdoor Lighting Service	ALS, SLS, SLR, SFLS	-	-	-
Demand Rate Classes (dollars per kilowatt)				
Medium General Service	MGS, GS-TES, AP-TES, SGS-TOU	1.44	(0.38)	1.06

Rate Class	Applicable Schedule(s)	Prospective Rate	Rolling Recovery Factor	Combined Rate*
Non-Demand Rate Class (dollars per kilowatt-hour)				
Large General Service	LGS, LGS-TOU	1.50	0.06	1.56

*Incremental Rates, shown above, include North Carolina regulatory fee of 0.13%.

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.G.S. § 62-133.14, and Commission Rule R8-70.

Under N.C.G.S. § 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 calculated using 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.G.S. § 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 Michael C. Maness.

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 $8.488 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.

Section 62-133.14(b)(2) states that 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 his affidavit filed with the Commission, Public Staff witness Maness 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. He 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. He 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. However, 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. He 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 on the record, the Commission concludes that, pursuant to N.C.G.S. § 62-133.14(b)(1), DEP is 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 $8.488 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.G.S. § 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 Michael C. Maness.

The Company requested annual costs of $20.660 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, 2020, through November 30, 2021, and an estimated $69.088 million for annual non-fuel operating costs over the period December 1, 2020, to November 30, 2021. Under N.C.G.S. § 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 Maness did not oppose the recovery of these cost components in his 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 Agency 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 a decrease in DEP's regulatory fee to $0.201 million based on the decrease in the regulatory fee for the period December 1, 2020, through November 30, 2021. 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 Michael C. Maness.

Under N.C.G.S. § 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 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 reduction will not be included in JAAR revenue requirements from March 16, 2018 forward (effective date for new base rates). In this filing, the jurisdictional reallocation credit (revenue reduction) is not applicable for the test period January 2019 through December 2019 nor the prospective period December 2020 through November 2021.

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 Michael C. Maness.

The Company requested a Joint Agency Asset RRF decrement adjustment of $27.572 million related to the overrecovery of costs incurred through the test year ended December 31, 2019. 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.G.S. § 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 Maness did not oppose the return on this rate component in his 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 Michael C. Maness.

Pursuant to N.C.G.S. § 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-hour (kWh) or kilowatt (kW), to produce the rates reflected for each rate class, 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	0.00459	(0.00080)	0.00379
Small General Service	SGS, SGS-TOUE	0.00559	(0.00198)	0.00361
Medium General Service	CH-TOUE, CSE, CSG	0.00439	(0.00170)	0.00269
Seasonal and IntermittentService	SI	0.00468	(0.00402)	0.00066
Traffic Signal Service	TSS, TFS	0.00255	(0.00061)	0.00194
Outdoor Lighting Service	ALS, SLS, SLR, SFLS	-	-	-
Demand Rate Classes (dollars per kilowatt)				
Medium General Service	MGS, GS-TES, AP-TES, SGS-TOU	1.44	(0.38)	1.06
Large General Service	LGS, LGS-TOU	1.50	0.06	1.56

*Incremental Rates, shown above, include North Carolina regulatory fee of 0.13%.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

Public Staff witness Maness stated that based on its investigation of the Company's filing, the Public Staff found no adjustments that should be made to the calculations of either the prospective or RRF revenue requirement. The Public Staff, therefore, recommended that the rates requested by the Company be approved, to become effective for the rate period. In light of the foregoing, the Commission finds that the rates calculated by the Company, which were recommended by the Public Staff, are just and reasonable and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That DEP shall be allowed to charge in a rider $127.131 million ($154.703 million as the prospective component and ($27.572) 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 to implement these approved rate adjustments to be effective for service rendered on and after December 1, 2020, as soon as practicable, but not later than ten days after the date that the Commission issues orders in this docket as well as in Docket Nos. E-2, Subs 1250, 1251, and 1254; and

4. That DEP shall work with the Public Staff to jointly prepare a proposed notice to customers of the rate adjustment ordered by the Commission in this Docket, as well as in Docket Nos. E-2, Subs 1250, 1251, and 1254, 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 November, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-2, SUB 1254

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Progress, LLC, for Approval of CPRE Cost Recovery Rider Pursuant to N.C.G.S. § 62-110.8 and Commission Rule R8-71	))))	ORDER APPROVING CPRE RIDER AND CPRE PROGRAM COMPLIANCE REPORT

HEARD: Tuesday, September 15, 2020, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina (Public Witness Hearing, Hearing Examiner Heather Fennell, Presiding)

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

APPEARANCES:

For Duke Energy Progress, LLC:

Jack E. Jirak, Duke Energy Corporation, NCRH 20/ P.O. Box 1551, Raleigh, North Carolina 27602-1551

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

Christina D. Cress, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

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

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

For North Carolina Sustainable Energy Association (NCSEA):

Benjamin Smith, NCSEA, 4600 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Dianna Downey, Chief Counsel, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

Layla Cummings, Staff Attorney, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

BY THE COMMISSION: North Carolina General Statutes Section 62-110.8(g) and Commission Rule R8-71 require the Commission to conduct an annual proceeding to review costs incurred or anticipated to be incurred by an electric public utility to comply with the Competitive Procurement of Renewable Energy (CPRE) Program pursuant to N.C. Gen .Stat. § 62-110.8 and an annual compliance report filed by the electric public utility pursuant to Rule R8-71(h).

On June 9, 2020, Duke Energy Progress, LLC (DEP or the Company) filed an application pursuant to N.C.G.S. § 62-110.8 and Commission Rule R8-71 for Approval of CPRE Compliance Report and CPRE Cost Recovery Rider, along with the direct testimony and exhibits of Bryan L. Sykes, Rates and Regulatory Manager, and Phillip H. Cathcart, Renewable Compliance Manager in the Business Development & Compliance Department.

Petitions to intervene were filed by Carolina Utility Customers Association, Inc., (CUCA) on June 17, 2020; by the North Carolina Sustainable Energy Association (NCSEA) on June 25, 2020; and by the Carolina Industrial Group for Fair Utility Rates II (CIGFUR) on August 25, 2020. The Commission granted CUCA's petition to intervene on June 18, 2020, NCSEA's petition to intervene on June 26, 2020, and CIGFUR's petition to intervene on August 25, 2020. The intervention of the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On June 29, 2020, 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 DEP rebuttal testimony; required the provision of appropriate public notice; and mandated compliance with certain discovery guidelines.

On August 7, 2020, the Commission issued an Order Scheduling Remote Witness Hearing for Expert Witness Testimony due to the COVID-19 pandemic. All parties consented to the remote hearing.

On August 24, 2020, DEP filed the supplemental testimony and revised exhibits and workpapers of witness Sykes. In his supplemental testimony, witness Sykes presented revised rates reflecting the impacts related to two updates to numbers presented in his direct exhibits and workpapers, which resulted in lower customer rates for the billing period.

On August 25, 2020, the Public Staff filed the testimony and exhibit of Jeff Thomas, an engineer with the Public Staff Energy Division, and Michelle M. Boswell, Accounting Manager – Electric Section in the Public Staff Accounting Division.

On September 9, 2020, the Public Staff and DEP filed a motion to excuse all Public Staff and Company witnesses and represented that counsel for the Public Staff consulted with counsel for all parties to the docket, that all parties agreed to waive cross-examination of the Public Staff and DEP witnesses, and that the parties offered no objection to the introduction of the witness testimony and exhibits into the record as requested.

On September 10, 2020, the Commission issued an Order Excusing Witnesses, Accepting Testimony, Canceling Expert Witness Hearing, and Requiring Proposed Orders, which excused the DEP and Public Staff witnesses from testifying at the expert witness hearing, received the witnesses' prefiled testimony and exhibits into the record, canceled the expert witness hearing, and set a deadline of October 16, 2020, for the parties to file proposed orders or briefs.

On September 14, 2020, DEP filed affidavits of publication indicating that the public notice had been provided in accordance with the Commission's procedural order.

The matter came on for public witness hearing as scheduled on September 15, 2020, however, no public witnesses appeared.

On October 16, 2020, DEP and the Public Staff filed a Joint Proposed Order.

Based upon the Company's verified application, the testimony, workpapers and exhibits received into evidence, and the record as a whole, the Commission makes the following

FINDINGS OF FACT

1. DEP is duly organized as a 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 Commission as a public utility. DEP is lawfully before this Commission based upon its application filed pursuant to N.C.G.S. § 62-110.8 and Commission Rule R8-71.

2. The test period for purposes of this proceeding is the 32 months ended March 31, 2020 (test period). The billing period for this proceeding is the 12-month period beginning December 1, 2020, and ending November 30, 2021.

3. In its application and its direct and supplemental testimony (including workpapers and exhibits) in this proceeding, DEP identified $1,200,707 of test period charges on a system basis incurred to implement the CPRE Program. There were no purchased power costs during the test period. The test period charges requested by DEP were used to determine its proposed Experience Modification Factor (EMF) rider and consisted solely of CPRE Program implementation costs experienced during the test period. Of the system-basis test period charges, $733,398 was allocated to North Carolina retail customer classes. Since this was the first CPRE Program rider filing made to comply with N.C.G.S. § 62-110.8 and Commission Rule R8-71, the full amount of the test period charges was under-recovered.

4. The Company's system-basis implementation charges for the test period were reasonably and prudently incurred.

5. The Company allocated test period and prospective period implementation charges to its North Carolina retail jurisdiction using a composite allocation factor based on the weighted average of its energy and capacity costs determined for its prospective billing period. The composite allocation factor was 61.08%.

6. The North Carolina retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 37,852,870 megawatt-hours (MWh). The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	16,191,429
Small General Service	1,939,476
Medium General Service	10,847,985
Large General Service	8,524,536
Lighting	349,444
Total	**37,852,870**

7. In its application and its direct and supplemental testimony (including exhibits) in this proceeding, DEP requested a total increase of $2,522,720, on a system basis, of billing period charges anticipated to be incurred for purchased power and ongoing implementation costs. Of the system-basis billing period charges, $1,540,891 was allocated to the North Carolina retail jurisdiction.

8. The North Carolina retail jurisdictional allocation factors related to the capacity and energy components of purchased power costs anticipated to be incurred during the billing period in this proceeding are 60.07% and 61.35%, respectively. The capacity component is based on the 2019 production plant allocation factor and the energy component was based on projected billing period sales. Similarly, the North Carolina retail class allocation factors related to the capacity and energy components of purchased power costs anticipated to be incurred during the billing period in this proceeding are based on 2019 production plant allocation factors and projected billing period kilowatt-hour (kWh) sales for each class, respectively. The North Carolina retail class allocation factors related to implementation charges anticipated to be incurred during the billing period and actually incurred during the test year (for purposes of calculating the EMF) are based on a composite allocation factor calculated as the weighted average of the capacity and energy components of purchased power.

9. The projected billing period sales for use in this proceeding are 37,750,364 MWh on a North Carolina retail basis. The projected billing period for North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	16,171,290
Small General Service	1,784,993
Medium General Service	10,287,749
Large General Service	9,128,353
Lighting	377,978
Total	**37,750,363**

10. DEP's experienced North Carolina retail under-recovery of costs for the extended initial test period, or EMF period, the 32-month period starting August 1, 2017, and ending March 31, 2020, amounts to $733,398, excluding the regulatory fee. DEP under-recovered its

CPRE EMF costs for the extended initial test period by $321,998 for the Residential class, $37,296 for the Small General Service class, $202,989 for the Medium General Service class, $165,289 for the Large General Service class, and $5,827 for the Lighting class.

11. The appropriate monthly CPRE EMF rates to be charged to customers are 0.002 cents per kWh for the Residential class, 0.002 cents per kWh for the Small General Service class, 0.002 cents per kWh for the Medium General Service class, 0.002 cents per kWh for the Large General Service class, and 0.002 cents per kWh for the Lighting class, excluding the regulatory fee.

12. The appropriate North Carolina retail prospective billing period expenses amounted to a total of $1,540,891, excluding the regulatory fee. The appropriate prospective billing period expenses for use in this proceeding are $676,527 for the Residential class, $78,360 for the Small General Service class, $426,486 for the Medium General Service class, $347,277 for the Large General Service class, and $12,242 for the Lighting class.

13. The appropriate monthly prospective CPRE Rider rates to be charged to customers are 0.005 cents per kWh for the Residential class, 0.005 cents per kWh for the Small General Service class, 0.005 cents per kWh for the Medium General Service class, 0.004 cents per kWh for the Large General Service class, and 0.003 cents per kWh for the Lighting class, excluding the regulatory fee.

14. The appropriate combined monthly EMF and CPRE Rider rates to be collected during the billing period are 0.007 cents per kWh for the Residential class, 0.007 cents per kWh for the Small General Service class, 0.007 cents per kWh for the Medium General Service class, 0.006 cents per kWh for the Large General Service class, and 0.005 cents per kWh for the Lighting class, excluding the regulatory fee.

15. The increase in costs the Company proposes to recover with its proposed EMF and CPRE Riders is within the limit established in N.C.G.S. § 62-110.8.

16. DEP is reasonably and prudently implementing the CPRE Program requirements of N.C.G.S. § 62-110.8.

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

The evidence for this finding of fact is contained in the testimony and exhibits of Company witnesses Sykes and Cathcart.

Witness Sykes testified that N.C.G.S. § 62-110.8 provides that an electric public utility shall be authorized to recover the costs of all purchases of energy, capacity, and environmental and renewable attributes from third-party renewable energy facilities and to recover the authorized revenue of any utility-owned assets that are procured through an annual rider approved by the Commission and reviewed annually. Commission Rule R8-71 prescribes that, unless otherwise ordered by the Commission, the test period for each electric public utility shall be the same as its test period for purposes of Rule R8-55. The test period for purposes of Rule R8-55 is the 12 months ending March 31. Witness Sykes testified that for the purposes of this proceeding, DEP's proposed rider includes both an EMF component to recover DEP's costs incurred during the test period as well as a component to collect costs forecasted to be incurred during the prospective 12-month period over which the proposed Rider CPRE will be in effect.

Witness Cathcart testified, however, that the Commission approved a modification to the Company's test period to be the 32-month period ending March 31, 2020, in its August 30, 2019 Order Cancelling Public Hearing, Approving Proposed Accounting Treatment, Authorizing Extended Test Period, and Approving 2018 CPRE Compliance Report in Docket No. E-2, Sub 1208.

Therefore, the Company's proposed test period in the proceeding is the 32 months beginning on August 1, 2017, and ending on March 31, 2020, and the billing period for Rider CPRE is the 12 months beginning on December 1, 2020, and ending on November 30, 2021.

The test period and the billing period proposed by DEP were not challenged by any party. Based on the foregoing, the Commission concludes the Company used the appropriate test period and billing period for this first Rider CPRE filing.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

The evidence for these findings of fact is contained in the testimony and exhibits of Company witnesses Sykes and Cathcart and the testimony and exhibits of Public Staff witnesses Thomas and Boswell.

On Exhibit No. 2, Company witness Sykes set forth the per books (system-level) implementation charges of $1,200,707 incurred by the Company to establish the CPRE Program and the amount of under-collection for purposes of the EMF. Company witness Cathcart testified regarding the Company's actions to implement the CPRE Program and to comply with the CPRE Program requirements of N.C.G.S. § 62-110.8, as described in the Company's 2019 CPRE Compliance Report. The Commission takes judicial notice of the Company's compliance report for calendar year 2018 as filed in Docket No. E-2, Sub 1208. Of the per books test period implementation charges, $733,398 was allocated to the North Carolina retail jurisdiction based on a composite allocation factor calculated as the weighted average of the capacity and energy components of purchased power.

The testimony of Public Staff witness Thomas attested to the system-level expenses sought for recovery during the test period. Witness Thomas did not recommend any adjustments to the system-level expenses or any adjustment to the allocation of system-basis test period charges to the North Carolina retail jurisdiction based on the composite allocation factor described above.

The testimony of Public Staff witness Boswell describes procedures taken by the Public Staff to evaluate whether the Company properly determined its per books CPRE Program costs and revenues during the test period. Witness Boswell did not recommend any adjustments to the per books costs.

No party challenged the prudency of the per books amount of $1,200,707. Further, no party challenged the composite allocation factor used to allocate system-level test period charges to the North Carolina retail jurisdiction.

The Commission concludes the $1,200,707 per books (system-level) costs incurred by the Company during the test period to implement the CPRE Program were reasonably and prudently incurred. Further, the Commission concludes the $733,398 of test period charges allocated to the North Carolina retail jurisdiction is appropriate to be recovered by the Company.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is contained in the supplemental testimony and exhibits of Company witness Sykes and the testimony of Public Staff witnesses Thomas and Boswell.

In his Revised Exhibit Nos. 3 and 4, DEP witness Sykes provided DEP's North Carolina retail jurisdictional allocation factor for CPRE Program implementation charges as 61.08%, which is the composite allocation factor based on the weighted average of capacity and energy purchases for purchased power costs.

Public Staff witnesses Thomas and Boswell each note the use of this composite allocation factor approach in their separate testimonies.

No other party presented evidence on the appropriateness of the North Carolina retail jurisdictional allocation factor as the composite allocation factor.

The Commission concludes the composite allocation factor of 61.08% used to allocate CPRE Program implementation charges to the North Carolina retail jurisdiction is appropriate for use in this 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 DEP witness Sykes and Public Staff witness Boswell.

In his Revised Exhibit No. 4, DEP witness Sykes provided DEP's normalized North Carolina retail sales for EMF purposes of 16,191,429 MWh for the Residential class, 1,939,476 MWh for the Small General Service class, 10,847,985 MWh for the Medium General Service class, 8,524,536 MWh for the Large General Service class, and 349,444 MWh for the Lighting class.

Public Staff witness Boswell noted these values in her testimony and stated that she did not propose any adjustments to the test period sales amounts used in this proceeding.

No other party presented evidence on the appropriateness of test period North Carolina retail sales.

The Commission concludes that the test period North Carolina retail MWh sales proposed by the Company and agreed to by the Public Staff for purposes of calculating the EMF billing factors are appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-8

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Sykes and Public Staff witness Thomas.

DEP witness Sykes presented in his Exhibit No. 2 and Revised Exhibit No. 3 DEP's projected CPRE Program costs in the billing period and the allocation of those costs to the North Carolina retail jurisdiction and the North Carolina retail customer classes. The Company used the 2019 production plant allocation factor of 60.07% for capacity costs and the projected billing period sales jurisdictional allocation factor of 61.35% for energy costs for its allocation of CPRE Program purchased power costs.

Public Staff witness Thomas stated that the Public Staff investigated DEP's estimation of system-level billing period costs and found them generally reasonable. Witness Thomas further stated that the Company's estimation of total energy production for each CPRE facility is based on one generic output profile for solar-only facilities and that the Company used the actual bid prices from each project's Power Purchase Agreement to estimate total costs.

Witness Thomas further testified that the Company requests to recover from its North Carolina retail customers its capacity costs based upon its 2019 production plant jurisdictional allocation factor of 60.07% and its energy costs based upon its projected billing period sales jurisdictional allocation factor of 61.35%. The Public Staff did not take exception to the use of these factors. The Public Staff also did not oppose the use of the 2019 production plant allocators and energy sales, respectively, to allocate North Carolina retail jurisdictional capacity and energy costs to the customer classes.

Public Staff witness Thomas also addressed the Company's use of a composite factor for allocating North Carolina retail implementation charges to the North Carolina retail customer classes. The Public Staff did not take exception to the use of a composite allocation factor.

No other party presented evidence on the appropriateness of the Company's proposed billing period charges anticipated to be incurred or the allocation of these costs to the North Carolina retail jurisdiction or customer classes.

The Commission concludes that the Company's system-level charges anticipated to be incurred during the billing period for purchased capacity and energy and ongoing implementation costs is appropriate for use in this proceeding. The Commission further concludes that the use of 60.07% for the capacity component and 61.35% for the energy component to allocate system-level CPRE Program purchased power costs to the North Carolina retail jurisdiction is appropriate for use in this proceeding and that the use of 2019 production plant and energy sales, respectively, to allocate North Carolina retail jurisdictional capacity and energy costs to the customer classes is appropriate for use in this proceeding. Further, the Commission concludes that the use of a composite factor for the allocation of North Carolina retail implementation costs to the North Carolina retail customer classes is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is contained in the testimony and Revised Exhibit No. 3 of Company witness Sykes and Public Staff witness Thomas.

In his Revised Exhibit No. 3, DEP witness Sykes provided DEP's projected billing period sales of 16,171,290 MWh for the Residential class, 1,784,993 MWh for the Small General Service class, 10,287,749 MWh for the Medium General Service class, 9,128,353 MWh for the Large General Service class, and 377,978 MWh for the Lighting class. Witness Sykes further testified that the Rider CPRE rate per customer class for purchased power is determined by dividing the sum of the billing period costs allocated to the class by the forecast billing period MWh sales for the customer class. Similarly, the Rider CPRE rate per customer class for implementation costs is determined by dividing the sum of the billing period costs allocated to the class, using a composite allocation factor determined in the purchased power calculation by the forecast billing period MWh sales for the customer class.

Public Staff witness Thomas testified as to the Company's request to recover capacity and energy costs based upon its projected billing period sales. Public Staff witness Thomas did not propose any adjustments to the projected billing period sales amounts used in this proceeding.

No other party presented evidence on the appropriateness of projected billing period North Carolina retail sales.

The Commission concludes that the Company's projected billing period sales for North Carolina retail customer classes is as follows: 16,171,290 MWh for the Residential class, 1,784,993 MWh for the Small General Service class, 10,287,749 MWh for the Medium General Service class, 9,128,353 MWh for the Large General Service class, and 377,978 MWh for the Lighting class.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-14

The evidence supporting these findings of fact appears in DEP's Application, in the direct and supplemental testimony and exhibits of DEP witness Sykes, and in the testimony of Public Staff witnesses Thomas and Boswell.

Witness Sykes' revised exhibits show a total of $733,398 under-recovery of CPRE Program costs for the EMF period, the initial test period starting August 1, 2017, and ending March 31, 2020. The prospective CPRE Program costs for the billing period, as shown through witness Sykes' revised exhibits, amounted to a total of $1,540,891.

In supplemental testimony, witness Sykes revised the components of the proposed total CPRE Rate to be effective December 1, 2020, and to remain in effect for the 12-month billing period ending November 30, 2021, as follows, excluding the regulatory fee:

DEP's Rider Request Filed on August 24, 2020 (cents per kWh)

Customer Class	EMF Rate	CPRE Rider Rate	Total CPRE Rate
Residential	0.002	0.005	0.007
Small General Service	0.002	0.005	0.007
Medium General Service	0.002	0.005	0.007
Large General Service	0.002	0.004	0.006
Lighting	0.002	0.003	0.005

Public Staff witnesses Thomas and Boswell testified that they reviewed and analyzed the CPRE Program costs for which DEP has requested recovery in this proceeding and found them to be appropriate.

Witness Boswell testified that the Public Staff's investigation included procedures intended to evaluate whether the Company properly determined its per books CPRE Program implementation costs and revenues during the test period. She stated that these procedures included a review of the Company's filing and other Company data provided to the Public Staff. Witness Boswell testified that performing the Public Staff's investigation required the review of numerous responses to written and verbal data requests as well as discussions with the Company.

The Commission finds the Company's proposed rates just and reasonable for purposes of this proceeding. Based on the Commission's findings in this proceeding, it is appropriate that DEP file with the Commission EMF rates and CPRE Rider rates consistent with the rulings in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Sykes and Public Staff witness Thomas.

DEP witness Sykes testified that N.C.G.S. § 62-110.8(g) limits the annual increase in costs recoverable by an electric public utility to (1%) of the electric public utility's total North Carolina retail jurisdictional gross revenues for the preceding calendar year. Further, he testified that Rul R8-71 provides that "[t]he annual increase in the aggregate costs recovered under N.C.G.S. § 62-110.8(g) in any recovery period from its North Carolina retail customers shall not exceed one percent (1%) of the electric public utility's North Carolina retail jurisdictional gross revenues for the preceding calendar year as determined as of December 31 of the previous calendar year." Witness Sykes testified that the increase in aggregate costs DEP seeks to recover in this proceeding is less than the statutory maximum.

Public Staff witness Thomas similarly concluded that the costs the Company seeks to recover are less than 1% of DEP's total North Carolina retail jurisdictional gross revenues for 2019.

The Commission concludes that the costs the Company seeks to recover in this proceeding are not in excess of the cost cap established by N.C.G.S. § 62-110.8(g).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding of fact is contained in the direct testimony and exhibits of Company witness Cathcart, including the 2019 CPRE Compliance Report.

Witness Cathcart and the 2019 CPRE Compliance Report detail the actions of the Company to implement the CPRE Program requirements of N.C.G.S. § 62-110.8. The 2019 CPRE Compliance Report describes the Company's efforts to implement the CPRE Program in collaboration with the Independent Administrator (IA). The IA's Final Report for Tranche 1 (Final Report) was included as Appendix A to the 2019 CPRE Compliance Report and provides substantial details regarding the Tranche 1 process and outcome. The Company was ultimately able to procure 2 projects totaling 85.72 MW at prices well below the avoided cost cap, resulting in substantial projected savings to customers relative to avoided costs.

The Final Report also describes the Company's efforts, along with the IA, to identify areas of improvement for Tranche 2, and the 2019 CPRE Compliance Report provides further details regarding the Company's plans for Tranche 2. The 2019 CPRE Compliance Report also includes all of the information required by Commission Rule R8-71(h), including a description of the CPRE Program solicitation undertaken by DEP during the reporting year, the avoided cost rates applicable to Tranche 1, confirmation that all renewable energy resources procured through Tranche 1 were priced at or below avoided costs, certification by the IA that all public utility and third-party proposal responses were evaluated under the published CPRE Program methodology and that all proposals were treated equitably in Tranche 1 during the reporting year. The

Commission takes judicial notice of the Company's compliance report for calendar year 2018 as filed in Docket No. E-2, Sub 1208.

The Public Staff did not challenge the reasonableness and prudence of the Company's implementation of the CPRE Program requirements of N.C.G.S. § 62-110.8. No other party presented evidence on this issue.

Therefore, the Commission concludes that the Company is in compliance with and has reasonably and prudently implemented the CPRE Program requirements of N.C.G.S. § 62-110.8.

IT IS, THEREFORE, ORDERED as follows:

1. That DEP's request to establish a CPRE Rider is approved and that this rider shall remain in effect for a 12-month period beginning on December 1, 2020, and expiring on November 30, 2021;

2. That DEP's request to establish an EMF Rider is approved and that this rider shall remain in effect for a 12-month period beginning on December 1, 2020, and expiring on November 30, 2021;

3. That DEP shall file the appropriate rate schedules and riders with the Commission to implement the provisions of this Order and amounts approved herein, as soon as practicable, but not later than ten days after the date of this Order;

4. That DEP 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 Nos. E-2, Subs 1250, 1251 and 1253, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten days after the Commission issues orders in all four dockets; and

5. That DEP's 2019 CPRE Compliance Report is hereby approved.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of November, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief 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 APPROVING ELECTRIC TRANSPORTATION PILOT, IN PART

HEARD: Thursday, November 21, 2019, at 10:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

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

Kendrick C. Fentress, Associate General Counsel, Duke Energy Corporation, 410 South Wilmington Street, NCRH 20/Post Office Box 1551, Raleigh, North Carolina 27602

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 East Six Forks Road, Suite 260, Raleigh, North Carolina 27609

Dwight Allen, Allen Law Offices, PLLC, 1514 Glenwood Avenue, Suite 200, Raleigh, North Carolina 27612

For North Carolina Sustainable Energy Association:

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

For North Carolina Justice Center and Southern Alliance for Clean Energy:

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

For Sierra Club:

Matthew D. Quinn, Lewis & Roberts, PLLC, 3700 Glenwood Avenue, Suite 410, Raleigh, North Carolina 27612

For the Using and Consuming Public:

Dianna Downey, Staff Attorney,[1] Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On March 29, 2019, Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP; collectively, Duke or the Companies), 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 (ET Pilot).

On April 4, 2019, the Commission issued an order requesting comments and reply comments on Duke's proposal. Petitions to intervene were filed by and granted for the North Carolina Sustainable Energy Association (NCSEA), Sierra Club, ChargePoint, Inc. (ChargePoint), Environmental Defense Fund (EDF), North Carolina Clean Energy Business Alliance (NCCEBA), Zeco Systems, Inc. d/b/a Greenlots (Greenlots), and jointly Southern Alliance for Clean Energy and the North Carolina Justice Center (SACE/NCJC). The intervention and participation by the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On or before July 5, 2019, initial comments were filed by NCCEBA, SACE/NCJC, ChargePoint, EDF, Greenlots, NCSEA, Sierra Club, and the Public Staff. Reply comments were filed by Duke, EDF, ChargePoint, Greenlots, SACE/NCJC, and Sierra Club. In addition, the Commission received over 30 consumer statements of position, most of which expressed support for the proposed ET Pilot.

By orders issued October 25, 2019 and November 1, 2019, the Commission scheduled a hearing in this matter and notified parties of the topics to be addressed. On November 21, 2019, the Commission held a hearing to obtain additional information on the public interest and ratemaking implications of Duke's proposed ET Pilot.

On December 17, 2019, the Commission issued an order requesting proposed orders from the parties. On February 28, 2020, proposed orders were filed by Duke, the Public Staff, Greenlots, and jointly by SACE, NCJC, EDF, and Sierra Club. In addition, Duke and ChargePoint filed a Settlement Agreement.

On April 24, 2020, Greenlots filed a motion requesting that the Commission allow parties to file comments and reply comments on the Settlement Agreement.

On May 5, 2020, ChargePoint and Duke filed separate responses in opposition to Greenlots' motion.

On June 3, 2020, the Commission issued an order denying Greenlots's motion to allow comments and reply comments on the Settlement Agreement.

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[1] Ms. Downey was subsequently named Chief Counsel of the Public Staff.

SUMMARY OF APPLICATION

Duke states that in 2011 the Commission first approved DEC's request to conduct a plug-in electric vehicle (EV) charging station load research study pursuant to which DEC provided EV charging stations with up to $1,000 of installation fees to 150 residential customers who bought or leased a plug-in EV in DEC's service area. Order Approving Study, *Application by Duke Energy Carolinas, LLC, for Approval of Proposed Study on the Impact of Charging Plug-in Electric Vehicles on the Grid*, No. E-7, Sub 969, (N.C.U.C. Mar. 22, 2011). DEC initiated the study with the objective of collecting data about its customers' EV charging behaviors for a two-year period to better understand the impact that charging EVs would have on power demand, transformers, cabling, and other infrastructure. By the conclusion of the study period, explains Duke, DEC had developed a baseline understanding of residential customer light-duty EV charging behavior, average energy consumption of EV charging, and average purchase and installation costs of early market electric vehicle supply equipment (EVSE). Duke further states that since the conclusion of the study the EV market has grown and evolved as more EV models have become available. Duke posits that EV adoption has occurred at more than twice the rate of traditional hybrids and that the EV market in North Carolina has increased significantly, with a compound annual growth rate of 39% since 2011. Further, Duke notes that in 2017, 2,055 passenger EVs were registered in North Carolina, and in August 2018, EVs made up 1.1% of North Carolina's light-duty vehicle market. Additionally, Duke explains, EV technology has advanced significantly since DEC conducted the initial study. For example, EVs now contain larger batteries, charge at higher power levels, and have expanded to multiple market segments not previously offered. Duke notes that forecasts indicate the future adoption of passenger EVs in North Carolina will range from 3% to 8% of light-duty vehicle stock by 2025, depending on several influencing factors, including: a) vehicle availability, b) infrastructure availability, and c) state and local EV policies.

Duke takes the position that more investment in EV charging infrastructure will accelerate EV adoption in the state, consistent with the intent of certain state policies, such as those set forth in Executive Order No. 80 issued by Governor Roy Cooper on October 29, 2018 (EO 80), as well as with the fast-developing EV market. To that end, Duke has conducted research to demonstrate the potential benefits to the electric system and to customers of increased EV adoption and the potential for utility-managed charging to enhance those benefits. Duke explains that it designed the proposed ET Pilot to determine best practices for realizing significant potential benefits of increased electric transportation adoption in North Carolina, including the long-term potential for downward rate pressure, retaining fuel cost savings in North Carolina, reducing vehicle emissions, and improving air quality.

Description of the ET Pilot

The ET Pilot consists of seven programs to be in effect over a three-year period addressing three areas of concern: EV charging management, transit electrification, and public charging expansion. For EV charging management, Duke proposes the residential EV charging program and the fleet EV charging program. For transit electrification, Duke proposes the EV school bus charging program and the EV transit bus charging program. For public charging expansion, Duke proposes the multifamily dwelling charging station program, the public Level 2 charging station program, and the direct current fast charging station program. Duke attached proposed tariffs for each of the programs to its application.

EV Charging Management

- *Residential EV Charging*: Designed to evaluate whether providing a rebate to support the installation of EVSE encourages EV adoption and to establish procedures to determine the value and viability of utility-managed charging. The program provides a rebate of $1,000 for up to 500 DEC and 300 DEP residential customers in exchange for participation in the program, which will include transmission of charging load data to the utility as well as utility management of home charging during defined hours.

- *Fleet EV Charging*: Designed to support the installation of EVSE for public and private entity fleets, to encourage the use of EV fleets, and to collect utilization characteristics of EV fleet charging behavior for a variety of EV types and weight classes to better understand potential grid and utility impacts of this EV market segment. The program provides a $2,500 rebate to commercial and industrial customers that operate fleet vehicles. Participating customers must install all EVSE behind a separate meter taking service on an available commercial time-of-use (TOU) rate. DEC will offer no more than 500 total EVSE rebates, and DEP will offer no more than 400 total EVSE rebates.

Transit Electrification

- *EV School Bus Charging*: Designed to facilitate the replacement of older diesel school buses with zero-emission school buses in public school transportation systems, the installation of EVSE to facilitate market adoption, and the collection of data on utilization and other load characteristics to understand grid and utility impacts and explore the potential for bidirectional power flow from EV school bus (EVSB) batteries. Under this program DEC and DEP seek to aid in the deployment of approximately 55 and 30 electric school buses, respectively, by funding up to $215,000 per bus on a first-come, first-served basis to school districts willing to purchase an electric school bus with bidirectional power flow capabilities. Participating customers will allow access to all vehicle charging data and perform testing of charging load management and bidirectional charging capabilities. By testing the bidirectional capabilities of an EVSB, the school bus battery will operate as a grid asset, and Duke will retain the right to repurpose the EVSB battery after its useful vehicle life as a second-life storage asset.

- *EV Transit Bus Charging*: Designed to support EV transit bus (EVTB) adoption and to collect data on utilization and other load characteristics to understand potential grid and utility impacts. DEP and DEC will install and own qualifying EVSE selected by the transit agency. In DEC 60 stations would be eligible for funding, and in DEP 45 stations would be eligible for funding.

Public Charging Expansion

- *Multifamily Dwelling Charging*: Designed to provide access to residential charging for residents of multifamily dwellings. DEC and DEP will install, own, and operate Level 2 (L2) EVSE and collect a charging fee based on the marginal energy component of the applicable utility's currently approved Small General Service schedule, plus $0.02/kilowatt-hour (kWh) to cover network platform and transaction fees. Duke proposes to deploy 100 stations in DEC's service territory and 60 stations in DEP's. DEC and DEP will offer multiple brands of EVSE hardware from which the site host can select.

- *Public Level 2 Charging*: Designed to provide a base level of destination charging for drivers in DEC's and DEP's service territories. DEC and DEP will install, own, and operate L2 EVSE and collect a charging fee based on the marginal energy component of the applicable utility's currently approved Small General Service schedule, plus $0.02/kWh to cover network platform and transaction fees. Duke proposes to deploy 100 stations in DEC's service territory and 60 stations in DEP's.

- *Direct Current Fast Charging (DCFC)*: Designed to deploy a foundational level of fast charging infrastructure to facilitate long-distance travel throughout the service territories. DEC intends to install, own, and operate a network of up to 70 fast chargers across approximately 35 individual locations in its service territory, and DEP intends to install, own, and operate a network of up to 50 fast chargers across approximately 25 individual locations in its service territory. Stations will include charging equipment with electrical demand requirements of 100 kW or greater.

Program Costs

Over the proposed three years of the Pilot, DEC's estimated cost for the ET Pilot is $45,580,250, and DEP's estimated cost is $30,438,250. Duke provided the following cost breakdown per utility, per program.

	DEC	**DEP**
Residential Rebate	$1,175,000	$705,000
C&I Fleet Rebate	$1,925,000	$1,540,000
EV School Bus	$11,981,750	$6,535,500
EV Transit Bus	$4,671,000	$3,503,250
Multifamily L2	$1,285,000	$771,000
Public L2	$1,285,000	$771,000
DC Fast Charge Network	$20,107,500	$14,362,500
Education and Outreach	$2,025,000	$1,350,000
Ongoing O&M	$1,125,000	$900,000
Utility Total	$45,580,250	$30,438,250
Combined Total		**$76,018,500**

Although the application does not seek cost recovery for the ET Pilot, the Companies state that DEC and DEP intend to seek to recover the costs of the ET Pilot programs through their respective base rates.

SUMMARY OF COMMENTS, TESTIMONY, AND SETTLEMENT

Initial Comments

Public Staff

The Public Staff conducted a detailed investigation of the application and DEC's and DEP's responses to numerous data requests, as well as a review of pilot programs of other electric utilities and discussions with other stakeholders and state agencies from in and outside North Carolina. As a result of this investigation the Public Staff concludes that the proposed ET Pilot does not meet the parameters of a pilot in which DEC and DEP would undertake a proof-of-concept through a scalable project. The Public Staff concludes that DEC and DEP have failed to demonstrate that the estimated cost of the ET Pilot is necessary to learn more about serving current and future EV load. The Public Staff notes that the Companies and their affiliates have conducted similar programs both in North Carolina and in other jurisdictions, and the Public Staff takes the position that DEC and DEP have provided no evidence demonstrating that North Carolina customers are sufficiently unique to justify another pilot program or that the results of previous or ongoing pilot projects and other publicly available industry data are insufficient to meet Duke's needs. The Public Staff takes the position that DEC and DEP are requesting preapproval of infrastructure investments associated with electric transportation that would be funded by customers and notes that absent a certification requirement, the Commission generally does not preapprove utility capital investments. Ultimately, the Public Staff recommends that the Commission deny the application.

With respect to the scope of the ET Pilot, the Public Staff takes the position that the ET Pilot is designed to obtain infrastructure-related data that is likely already publicly available, or will be available within the next 12 to 18 months, from other utilities and jurisdictions. That data includes load patterns related to EV charging, the impact of managed charging, and how managed charging can shape load patterns and customer charging behavior. Additionally, the Public Staff notes that because EV-related loads are not weather sensitive, load shapes experienced by other utilities (residential and nonresidential) should be indicative of the load shapes of North Carolina consumers. The Public Staff concludes that there is no reason to believe that the results of a North Carolina pilot would find otherwise. The Public Staff also believes that any EV-related tariffs developed by other utilities would likely be adaptable in North Carolina. In short, the Public Staff concludes that there is no reason to duplicate those efforts here by approving the ET Pilot.

The Public Staff suggests that only the Residential EV Charging and Fleet EV Charging programs arguably qualify as pilots, but there are critical omissions from those programs that would support such a finding. The Public Staff notes that while the Residential EV Charging program would evaluate active managed charging via onboard load control capabilities in the second year, the program does not evaluate passive managed charging through experimental rate designs and other mechanisms. The Public Staff notes that any pilot project should explore the vast array of mechanisms to determine what drives, and does not drive, customer behavior. The Public Staff notes that the Fleet EV Charging program is similarly lacking in experimental rate designs and that the inclusion of various experimental rate designs and other mechanisms would render these programs more characteristic of a pilot.

The Public Staff takes the position that the various public charging station programs are merely capital projects and that no unique learning opportunities arise out of the construction of charging stations across the state, especially given the cost.

With respect to evaluation and metrics, the Public Staff notes that the value of a pilot project is to allow a utility to test a concept at a smaller scale without incurring significant costs that ultimately would be borne by customers. A pilot must have clearly defined objectives and goals that would define success (or failure) and justify (or not) a broader, permanent program. The Public Staff concludes that the ET Pilot contains no objectives, metrics, goals, or other means of evaluating whether the programs are a success or failure.

With respect to the cost-benefit analysis filed by DEC and DEP in support of the application, the Public Staff notes the similarity to other cost-benefit studies conducted by the same author for other utilities in other jurisdictions, including Duke Energy Florida, LLC (DEF). Overall, the Public Staff believes these studies to be reasonable attempts at quantifying the benefits and costs of EV adoption at various levels in a general sense. However, the Public Staff identifies several concerns with the study, including the use of a more carbon-intensive generation portfolio than DEC and DEP anticipate in their IRPs when estimating typical emissions per kWh of electricity as well as the high degree of uncertainty in the projections of EV penetration beyond 2025. Ultimately, the Public Staff takes the position that the Commission should give limited weight to the study. The Public Staff points out, though, that the cost-benefit analysis was not intended to provide a template for a cost-benefit analysis for each of the individual programs in the ET Pilot and that DEC and DEP have not conducted cost-benefit analyses for the individual programs. The Public Staff notes that individual program cost-benefit analyses should be performed to ensure that spending on any individual program is cost-beneficial.

NCSEA

NCSEA supports the deployment of EVs and charging infrastructure but cautions that such investment should be made in a way that supports all market participants. NCSEA requests that the Commission open a stand-alone proceeding to examine the issue and determine the goals of deploying EV charging infrastructure. NCSEA further requests that the Commission deny the Companies' petition to make capital investments for EV infrastructure and, instead, direct Duke to develop and propose an EV "make-ready" program.

NCSEA disagrees with the Companies' assertion that the ET Pilot would allow the Companies to install a foundational level of charging stations in North Carolina and states that through data requests Duke provided conflicting information on whether the Companies will be providing a significant number of the total stations needed to support EV demand and the goals of EO 80. According to NCSEA, this results from Duke's confusing plugs with stations, ignoring already expanding EV infrastructure in the state, and excluding Tesla stations from its analysis, all of which NCSEA deems improper. NCSEA opines that through the ET Pilot the Companies will serve roughly two-thirds of the EV market.

NCSEA expresses concerns that Duke's knowledge of the grid is more problematic than the Companies acknowledge with respect to the development of the market. Rather than using Customer Site Investigations, NCSEA argues that the Companies should not proceed with the ET Pilot until they can more economically evaluate potential sites using integrated distribution planning or hosting capacity maps. Further, NCSEA is concerned that the Companies' knowledge of the grid could be used to monopolize the market for EV infrastructure. Essentially, NCSEA believes that the Companies' knowledge of where expensive upgrades would be required would cause Duke not to use those sites and to leave the expensive sites for potential competitors.

NCSEA also questions the Companies' focus on the DCFC market as opposed to Level 2 plugs and hybrid gas/electric vehicles. NCSEA states that the DCFC plugs are not currently compatible with demand-side management methods like Level 2 plugs and could increase load, which would require more peaking generation capacity.

NCSEA agrees with the Companies' goal to provide underserved communities with access to charging stations but questions whether the Companies' proposal facilitates the achievement of that commitment.

NCSEA disagrees with the Companies' proposal to recover some of its EV costs through base rates while competing providers will have to rely solely on their EV customers. NCSEA argues that this proposal amounts to prohibited single-issue ratemaking outside the context of a general rate case. NCSEA advocates for a make-ready program in which the Companies would provide infrastructure to the point where a charging station could be installed by another provider. NCSEA argues this would be consistent with the Companies' line extension policies approved by the Commission.

NCSEA is not opposed to the rebates in the Companies' proposal but requests that the rebates be decreased from $1,000 to $500. As to rate design, NCSEA opposes the Companies' proposed TOU rate and suggests the Companies should develop EV-specific tariffs including no demand charge, a fixed charge relating to customer-specific costs, and a time-varying energy rate.

NCSEA opposes the first-come, first-served basis of the EV School Bus and EV Transit Bus programs, arguing that would benefit wealthier counties and cities that would use up the rebates before poorer areas are able to participate. NCSEA suggests that the Commission implement some "scoring criteria" to ensure the rebates are given equitably across the state.

Lastly, NCSEA asks the Commission to require the Companies to hire a third party to market the program and increase reporting to the Commission.

NCCEBA

NCCEBA opposes the proposed ET Pilot, taking the position that the proposal will have a substantial and deleterious effect on the EV charging market in North Carolina. NCCEBA asserts that the Companies' entry into the market will create an encroachment of monopoly activity into a growing competitive market. Further, NCCEBA states that the Companies will control 25% of Level 2 charging stations and 50% of DCFC stations. NCCEBA also disagrees with the Companies' view of the EV market and takes the position that the EV market is currently expanding quickly enough to meet market needs.

SACE/NCJC

SACE/NCJC generally support the Companies' proposed ET Pilot, recognizing many positive impacts of EVs, including lower cost, downward pressure on electric rates, and environmental benefits. SACE/NCJC also note impediments to EV adoption, including costs of EVs and general lack of knowledge. SACE/NCJC suggest the following modifications to the ET Pilot: 1) strengthen the reporting requirements to require quarterly reports and concrete details to enable analysis; 2) establish a stakeholder advisory council to help the Commission oversee aspects of the ET Pilot; 3) allocate a certain number of EV charging stations to disadvantaged communities; 4) increase funding for EVSB and EVTB in lower-income school districts and communities; and 5) develop EV rates to send clear price signals to customers to encourage charging during off-peak times of day, reducing the costs of charging EVs and reducing the need for new load to meet demand.

Finally, SACE/NCJC state that utilities have an important role to play in the emerging EV market. However, the organizations support a competitive market for charging infrastructure and may not support utility ownership and operation of EV charging stations in the future.

Greenlots

Greenlots supports the ET Pilot and encourages the Commission to approve the ET Pilot as proposed. Greenlots opines that the proposal is an example of needed, prudent, and targeted utility investment that will have a significant impact in accelerating the growth of the EV market and meeting the greenhouse emission goals of EO 80. According to Greenlots, EV adoption faces several impediments in the state, including a lack of fast charging stations and general charging infrastructure, mostly notably public charging stations, and that this leads to a lack of adoption due to what Greenlots called "range anxiety." Greenlots also lists a number of benefits to be derived from EV deployment, including cost savings, as well as improvements in the environment, general health, energy security, and grid resilience. Greenlots expresses disappointment that the proposal is only pilot scale and not program scale.

In addition, Greenlots does not agree that the ET Pilot will hinder the development of a competitive market. Rather, Greenlots contends that the ET Pilot will support the growth of the competitive market by growing the EV market as a whole and, therefore, increasing the demand for additional charging stations in the marketplace. Moreover, Greenlots states that drivers adopt EV technology due to the availability of charging stations, not necessarily the number of different providers and price.

EDF

EDF expresses support for the ET Pilot and the Companies' commitment to expanding the EV market as outlined in EO 80. EDF suggests several changes to the programs included in the ET Pilot, as follows: 1) the inclusion of on-bill financing for the purchase of EVSB and EVTB in which financing of those buses would be included on the transit agency or the school district's bill; 2) the inclusion of bill protection to protect participants from potentially dramatic and unexpected higher demand charges from higher usage that could move the customer into a higher rate class; 3) multiple rate designs, including those that incentivize charging during off-peak periods, and tariffs that are volumetric and offer different structures that include a demand charge; and 4) the establishment of a working group to further study how to remove barriers to EV adoption.

Sierra Club

Sierra Club expresses general support for the ET Pilot but suggests the following modifications: 1) the Companies should clarify their data collection plan, issue quarterly reports, and establish a stakeholder advisory process; 2) the Companies should use data from the residential EV charging program to develop EV-specific TOU rates; 3) the Companies should clarify the types of vehicles eligible for the program and whether single entities can receive multiple rebates; 4) the Companies should evaluate options to incentivize off-peak charging for multifamily dwelling units; 5) the Companies should report prices charged to EV drivers at DCFC locations and co-locate DCFC stations with Level 2 stations; and 6) the Companies should develop additional solutions for clean transportation access for low- and moderate-income communities.

ChargePoint

ChargePoint opposes certain components of the ET Pilot and takes the position that several components will delay the development of a long-term, sustainable competitive market. ChargePoint outlines three models for utility investment in EV infrastructure: 1) ownership by the utility; 2) make-ready; and 3) rebate-based. ChargePoint contends that the focus of utility investment should be to foster and support the existing competitive market, spur EV adoption, and support further development of the competitive market. According to ChargePoint, the Commission should consider the variety of technologies available, the degree to which site hosts can make choices about operating, and the impact of spurring private investment alongside utility customer funds.

ChargePoint further maintains that the lack of choice for participating customers among EV charging networks and not allowing participating customers to operate EV charging stations on their own property would adversely impact the existing competitive EV charging market. It agrees that an increase in EV charging infrastructure is needed but opines that such does not require the utility to bypass the existing market and local site hosts by owning and operating the charging stations. ChargePoint asserts that the ET Pilot would allow Duke to position itself to occupy a substantial position in the developing EV charging market, particularly with the DCFC program.

ChargePoint advocates for certain amendments to the ET Pilot programs, including using multiple charging networks and equipment vendors to reinforce competition and provide consumer choice and enabling site hosts under all offerings to operate charging stations and determine prices to drivers. Finally, ChargePoint advocates for the Commission to consider alternative utility investment models such as rebates and make-ready programs.

Reply Comments

Duke

Duke focuses its reply comments on the following: 1) the alignment of the ET Pilot with EO 80, 2) the broad support of the pilot from stakeholders and intervenors, and 3) the contention that the proposal is appropriately framed as a pilot so Duke can prepare for increased EV usage. Duke contends that contrary to NCSEA's and NCCEBA's assertions, Duke's efforts to develop a program that will support EV adoption across the state can benefit potential market entrants by jumpstarting the market. Further, Duke asserts that the Public Staff's opposition is based on overreliance on traditional ratemaking concepts that ignores the realities of a changing environment and is based on form over substance. In response to criticisms regarding lack of metrics or standards for evaluating the programs, Duke agrees to commit to an evaluation, measurement, and verification (EM&V) analysis of the impact of all segments of the ET Pilot to ensure that the goals of the pilot are met and to engage an expert in how the programs can be evaluated. Duke asserts that its proposal is not simply an effort to seek preapproval of cost recovery for the investments and expenses that it expects to incur but acknowledges that it will seek to recover its prudently incurred costs in a general rate case proceeding. Finally, given the concerns raised over the size and scope of the proposal, Duke offers to remove the multifamily charging stations and the public L2 charging stations from the ET Pilot, resulting in a decrease of approximately $4.1 million from the overall cost, and indicates a willingness to reduce the rebate for the Residential EV Charging Program from $1,000 to $500.

SACE/NCJC

SACE/NCJC reiterate their support for the ET Pilot with their previously requested modifications. They also disagree with the Public Staff that sufficient information will be publicly available without the ET Pilot and opine that information made available from the experience of other jurisdictions or other publicly available information will not be tailored to the Companies' customers and service territory. Finally, SACE/NCJC take the position that an independent EM&V process should be required and included in the cost of the ET Pilot.

Sierra Club

Sierra Club disagrees with the Public Staff's position that the ET Pilot is unnecessary because publicly available data either exists or will exist and contends that there are state-specific variations in the EV market, housing stock, customer demand, and utility operations. In addition, Sierra Club questions the Public Staff's position that other states that have initiated pilots will provide enough information for North Carolina's needs. Indeed, Sierra Club contends that the opposite is true and that the number of states initiating pilots shows the necessity of state-specific data. Finally, Sierra Club reiterates its recommendation for increased reporting of information.

ChargePoint

ChargePoint agrees with the positions stated by the Public Staff, NCSEA, and NCCEBA. Moreover, ChargePoint notes that SACE/NCJC admit that the ET Pilot would give the Companies a substantial stake in the EV charging market, including owning a majority of the DCFC stations.

Greenlots

Greenlots repeats its strong support for the ET Pilot, without delay, contending delaying or not providing drivers with these resources and more charging options would actually compound the fragile market conditions that parties advocating for delay critique. According to Greenlots, the private EV charging marketplace alone cannot adequately meet North Carolina's transportation electrification and emissions goals, let alone achieve market transformation or maximize future growth and associated benefits. In addition, Greenlots opines that there is a market void stemming largely from the fact that private equity funded development often requires rapid and high returns on investment that can be at odds with capital investments such as public EVSE. Additionally, Greenlots states that private market EVSE development and utility EVSE development is not a zero-sum game, as there can be an additive nature of utility investment. Greenlots encourages Duke and the Commission to consider ways in which the ET Pilot can be enhanced to incorporate and evaluate smart charging and other load management strategies.

Hearing

On November 21, 2019, the Commission held a hearing to obtain additional information on the public interest and ratemaking implications of Duke's proposed ET Pilot. For Duke, Lang Reynolds, Director of Electric Transportation, and Laura Bateman, Director of Carolina's Rates and Regulatory Strategy Group, appeared as a panel to respond to questions from the Commission.

Witness Reynolds stated that new technology is coming out every day and that while Duke has done studies in the past, there is a need for more data and for utility investment to support advanced market growth. He also asserted that there are significant differences in data from vehicles on different systems. Witness Bateman asserted that it is appropriate for the utility to install foundational infrastructure because there eventually will be system benefits for utility customers due to more efficient use of the electric system and there are public policy benefits. She likened the pilot to the job retention and economic development riders, which allow cross-subsidization for public benefits.

Regarding the relationship between the Volkswagen settlement funds and the EV school bus program, witness Reynolds agreed that if a school district applied to participate in the program and also received settlement funds, that district would get the full extended rebate up to the full cost of the bus. School districts in Cherokee, Wake County, New Hanover County, and a charter school in Chapel Hill have expressed an interest in the program.

Witness Reynolds stated in response to criticism regarding the size of the residential rebate that Duke is willing to reduce the rebate to $500. Duke's plan is to gather data the first year and perform charge management the second and third years of the residential program. However, the program would allow customers to opt out of managed charging. Experimental tariffs could come at the end of the pilot. Witness Reynolds stated that Duke intends to use the charging data to analyze the grid impacts of the programs.

Witness Bateman stated that for the portions of the pilot where Duke will be owning and operating the charging station or EVSE, those costs will include the cost of the upgrades to the grid needed to connect the charging stations. However, costs are not included if there were a situation in the DCFC program where the charger might be located in a remote area and needed very extensive upgrades. Those costs would the capitalized and recovered through depreciation and return in base rates. She estimated the charging stations would have an expected depreciable life of seven years.

Regarding why Duke did not choose to enroll existing EV owners and Duke customers in a pilot to gather data, witness Reynolds responded that the pilot was designed not only to gather data but to encourage new EV adoption. Witness Reynolds stated that Duke did not choose on-bill financing because research shows financial incentives drive customer behavior. Witness Bateman stated that the utilities have tried to stay away from on-bill financing because of the existence of lenders and other sources of financing separate and distinct from the utility.

Witness Reynolds responded to a question regarding how having school buses spread out over the system will provide useful learning regarding grid resiliency. He stated that Duke needs to understand whether it can provide grid services and, if so, how. Witness Reynolds admitted that Duke has data from across the state regarding its EV customers and that they tend to be clustered in the state's larger metropolitan areas. He expects that there will be some amount of balance from a first-come, first-served process. If Duke were to be required to set aside rebates for populations that might be difficult otherwise to enroll, Duke would need to expand the program.

Regarding whether Duke considered providing the infrastructure piece of the pilot through an unregulated subsidiary rather than the utilities, witness Reynolds stated that with the fast chargers, specifically, it is well-documented that they are not profitable on a stand-alone basis. Witness Bateman added that the usage is not enough to make it economical or profitable for an unregulated competitive provider. She stated that once it becomes profitable, then it would make more sense for the unregulated competitive market to take over.

Witness Bateman explained that the pilot provides numerous benefits for all customers, including customers that do not have EVs, such as environmental benefits. She further explained how EV adoption could lower the cost per kWh usage for all DEC and DEP customers. She noted that if the Companies were able to encourage off-peak charging, then there would be additional kilowatt-hours over which to spread fixed costs. This would result in a lower cost per kWh for all customers on the system.

When asked about the make-ready concept set forth by some intervenors, witness Reynolds indicated that the Companies already require commercial DCFC stations to pay some contributions in aid of construction and that, practically speaking, the utility is already socializing the majority of the cost on the utility side of the meter. Witness Reynolds indicated that Duke is proposing to own and operate the DCFC stations to ensure that the stations are well maintained and operable for the full life of the asset. With a make-ready program the utility puts in the make-ready infrastructure and has no recourse afterwards to ensure the station is useful or in good shape. Witness Bateman indicated that if the ET Pilot were limited to a make-ready program, the costs would still range from $41 to $64 million.

On questions from the Public Staff, witness Reynolds stated that the costs of the pilot are proportional in size to pilots in other states, such as South Carolina. Additionally, with respect to the Public Staff's comparison of the costs of Duke's North Carolina ET Pilot with DEF's ET program in Florida, witness Reynolds clarified that DEF is a single utility operating in a smaller area in Florida, whereas North Carolina has a larger area with two utilities participating in the ET Pilot.

With regard to a question from the Public Staff concerning whether the Company appeared to be asking for preapproval of infrastructure, witness Bateman answered that with a program of this significance, Duke needs direction from the Commission as to whether this foundational level of infrastructure is a proper investment for the utility to make. Witness Bateman compared this proceeding to two other fairly common Commission proceedings. First, witness Bateman compared this request to a certificate of public convenience and necessity, in which the utility builds a new transmission line or a new generation plant. The certificate does not guarantee cost recovery; instead, the certificate demonstrates the Commission's conclusion that the utility has justified its decision to construct the facility. The prudence and reasonableness of those costs remain subject to review in a general rate case when cost recovery is sought. Next witness Bateman noted that the Companies seek approval of demand-side management and energy efficiency programs prior to implementing them, with the prudency of those costs subject to later review by the Commission in a cost-recovery proceeding.

Settlement Among ChargePoint, DEC, and DEP

On February 28, 2020, DEC, DEP, and ChargePoint filed a Settlement Agreement. In summary, the settlement provides that customers in the residential program would have unlimited choice of L2 EVSE hardware. With respect to the EVSB program, the settlement provides that EVSE will be installed on the customer's side of the meter with participating customers having a choice of two or more vendors of EV charging hardware and software. The hardware and software would be prequalified by the Companies to meet functional requirements. For the DCFC program, the settlement provides that the Companies will install, own, operate, and maintain the fast chargers; that there will be a minimum of two fast chargers per location capable of charging a single vehicle at a combined demand of 100 kW or more; and that site hosts would have a choice of at least two vendors of EV charging hardware and software, which shall be prequalified by the Companies to meet functional requirements. In an effort to maintain an open market the settlement provides that no single vendor of EV charging hardware shall have more than 60% of the total installations and that once a percentage share for any single vendor of EV charging hardware exceeds 50% in a DEC or DEP service territory, either DEC or DEP, as applicable, will notify the vendor that it is approaching the threshold and establish a waiting list of customer applications for that vendor to be considered should other projects with other vendors not come to fruition. In addition, the Settlement Agreement grants site hosts the option of creating alternative pricing mechanisms for drivers, which, for purposes of the ET Pilot, may not exceed the DCFC fee by more than 20%.

The Settlement Agreement provides that customers participating in the EVTB program would have a choice of two or more EV charging hardware and software vendors, which shall be prequalified by the Companies to meet functional requirements.

Finally, the Settlement Agreement provides procedural mechanisms to enhance Commission review and oversight, and stakeholder engagement. Specifically, the Settlement Agreement calls for DEC and DEP to convene a series of collaborative meetings with stakeholders (the Electric Transportation Collaborative) to present interim ET Pilot progress and results and to gather feedback on the ET Pilot. The Settlement Agreement provides that Duke agrees to leverage the learnings from the ET Pilot as key inputs to the Comprehensive Rate Design Study proposed by Public Staff witness Floyd in Docket E-7, Sub 1214 to evaluate and develop effective rate design offerings for customers with EVs.

DISCUSSION AND CONCLUSIONS

As demonstrated by the comments in this proceeding there is general agreement that there are many potential benefits to electric ratepayers and society at large in the transition from gasoline- and diesel-powered vehicles to electric transportation. However, there are still many challenges to widespread adoption of EVs, some of which are tied to the lack of charging infrastructure.

Focused pilot programs can serve the purpose of expanding this charging infrastructure while allowing the utility to collect data on the impact of this new electric usage on its system. After carefully considering the goals, costs, and benefits of the seven programs proposed by Duke in its ET Pilot and the comments of the other parties in this proceeding, the Commission finds good cause to approve at this time the Public Level 2 Charging program, as proposed, and limited versions of the Multifamily Dwelling Charging, Direct Current Fast Charging, and EV School Bus Charging programs. Because the Commission declines at this time to approve several of the programs covered by the Duke and ChargePoint settlement, the Commission declines to adopt the Settlement Agreement filed by Duke and ChargePoint.

EV School Bus Charging

As one of its programs aimed at transit electrification Duke proposes to aid the deployment of modern, zero-emission electric school buses by providing funds to offset the incremental costs associated with the battery. In exchange for this funding the customer must allow access to all vehicle charging data and perform testing of charging load management and bidirectional charging capabilities. Duke believes the potential exists for significant cost savings to operators of electric school buses, diesel emissions reductions, and electric system benefits from the adoption of EV school buses in North Carolina. Under this program Duke will install and own the charging equipment and will retain the right to repurpose the battery as a grid storage asset at the end of its useful vehicle life. Duke argues that the potential use of the batteries as grid assets justifies the investment in this program. Duke proposes to fund on a first-come, first-served basis 55 electric school buses for school districts located in the DEC service territory and 30 electric school buses in the DEP service territory.

The Commission is interested in the potential to utilize batteries with bidirectional power flow capabilities in electric school bus fleets as a grid asset. However, the Commission is concerned that the potential for dispersion of the school buses under the program as it is now proposed limits the program's ability to test that potential at any scale. A more limited pilot, though, may be useful as the first step in a multiphase program. In that first step the utility can gather operational data with respect to charging characteristics, usage patterns, and technology issues relating to bidirectional power flow to and from the battery. The Commission expects that after this "proof of concept" pilot Duke may further propose in a second "proof of value" stage of this pilot program sufficiently scaled and concentrated clusters of electric school buses with bidirectional flow capabilities that will enable the utility to explore their potential as storage resources for local grid support.

The Commission, therefore, will approve at this time a reduced program that will provide funding to offset the purchase of 15 electric school buses by school districts in each of the DEC and DEP service territories, for the purpose of gathering operational data and exploring the technical capabilities of the vehicle-to-grid technology.

The Commission is not persuaded that the program should be rejected on the basis that it may benefit wealthier counties, as was argued by some parties. The program is necessarily limited as a pilot, but funds are available to any school district otherwise planning to replace a school bus. Moreover, as Duke states, it designed the program to complement anticipated funding from the Volkswagen Settlement Trust which is administered by the North Carolina Department of Environmental Quality (DEQ). Duke notes that DEQ intends to allocate a portion of the Settlement Trust funds to replace older diesel school buses with new diesel, propane, or electric school buses. Duke expects that the availability of funds from the Settlement Trust, combined with its proposed infrastructure investment, would encourage DEQ to work with school districts to replace a limited number of legacy high-emitting school buses with zero-emission, electric school buses.

Public Level 2 Charging

Duke proposes to install, own, and operate public Level 2 charging stations at key public destination locations to encourage EV adoption, as well as to collect utilization and other load characteristics to understand potential grid and utility impacts. As several parties note, access to reliable public charging stations is essential to building EV driver confidence. Despite improvements in the mileage range of newer EVs, the lack of public Level 2 charging stations is an impediment to greater adoption of EVs. Duke proposes to deploy 100 public Level 2 charging stations within the DEC service territory and 60 stations within the DEP service territory.

The Commission recognizes that some parties oppose Duke's ET Pilot and in particular, the Public Level 2 Charging program. Regarding this program, NCCEBA, for example, objects to the utility's participation in "a growing competitive market." Greenlots, however, counters that the ET Pilot will support the growth of the competitive market by growing the EV market as a whole and, therefore, increasing the market demand for additional charging stations. SACE/NCJC believe that utilities have an important role to play in the emerging EV market. As Greenlots states, the private EV charging marketplace alone cannot adequately meet North Carolina's transportation electrification and emissions goals, let alone achieve market transformation or maximize future growth and associated benefits.

Although Duke offered to remove this program from the ET Pilot, the Commission finds that the Public Level 2 Charging program has the potential to provide a number of benefits supporting the adoption of EVs, removing impediments, and collecting valuable system impact data while providing potential access to a broad cross-section of Duke's customers. The Commission is persuaded that the Public Level 2 Charging program is in the public interest and should be approved.

Direct Current Fast Charging (DCFC)

Duke further proposes to install, own, and operate a network of publicly accessible direct current fast charging stations throughout its utility service territories to facilitate long-distance travel. Duke proposes to install up to 70 DCFC stations across approximately 35 individual locations in its DEC service territory and up to 50 stations across approximately 25 individual locations in its DEP service territory.

Several parties oppose Duke's proposed DCFC program, either on the basis that it provides no unique learning opportunity or that Duke would garner too large of a percentage of what should be a competitive market. However, other parties argue that the utility has an important role to play in this emerging market. At the hearing, witness Reynolds stated that Duke is proposing to own and operate the DCFC stations to ensure that the stations are well maintained and operable for the full life of the asset. As noted above regarding the Public Level 2 Charging program, access to reliable public charging is essential for the growing EV market, and the lack of fast charging stations to facilitate longer distance travel is an impediment to greater adoption of EVs.

The Commission finds, based upon the record, that a limited version of the DCFC program as proposed by Duke is in the public interest and is approved. The Commission, therefore, will approve a limited version of the DCFC program approximately one-third the size of that proposed and will allow Duke to install, own, and operate up to 24 DCFC stations across approximately 12 individual locations in its DEC service territory and up to 16 stations across approximately 8 individual locations in its DEP service territory.

Multifamily Dwelling Charging

In its third program related to public charging Duke proposes to install, own, and operate Level 2 charging stations to provide access to residential charging for residents of multifamily dwellings. As Duke notes in its application:

> Limited ability to install charging infrastructure at a residence is commonly cited as a barrier for Multi-Family Dwelling ("MFD") tenants to purchase an EV. Accordingly, the Companies designed the ET Pilot to provide easy access to residential charging for non-homeowners throughout the Companies' service territories.

Duke proposes to deploy 100 stations in DEC's service territory and 60 stations in DEP's service territory.

The Commission is persuaded that as the cost of EVs decreases and more used vehicles become available it will be even more important for multifamily housing tenants to have convenient access to charging stations at their residence. While not all residents of multifamily housing are low or moderate income, many are, and several parties emphasized the need to specifically extend the benefits of the Pilot to low- and moderate-income ratepayers.

The Commission finds that a limited version of the program as proposed by Duke is in the public interest. The Commission, therefore, will approve as a pilot a Multifamily Dwelling Charging program half the size of that proposed, with Duke installing up to 50 Level 2 charging stations in the DEC service territory and up to 30 Level 2 charging stations in the DEP service territory.

Public Level 2 Charging, Direct Current Fast Charging (DCFC), and Multifamily Dwelling Charging Additional Programs

In approving these three components of the ET Pilot the Commission is not sanctioning an open-ended or broad, general participation by Duke in the EV charging infrastructure market. Rather, because the goals of the programs are to test public response to wider availability of public charging infrastructure and to acquire data and information on alternative implementation approaches for further analysis, the Commission supports the programs. Once those goals are met, any further participation by Duke in the market for charging infrastructure will be determined at the appropriate time and after full consideration of all pertinent factors.

The Commission further directs Duke to explore and create a second pilot of these three programs in a stakeholder process described below. The Commission expects Duke to explore in the second round of these three pilot programs and any other proposed programs additional ownership and partnership models for EV infrastructure, including utility fully owned and operated stations; make-ready stations with third-party owned charging equipment; and stations co-owned, co-funded, or co-operated by Duke in partnership with other entities.

Stakeholder Process and Criteria for Future Pilot Programs

The Commission is not persuaded that the other programs proposed by Duke are appropriately focused and sized, and therefore declines to approve those programs at this time. These programs, as currently proposed by Duke, have not been designed to sufficiently explore system benefits that would ultimately justify the estimated expenditure of ratepayer funds. Nevertheless, the Commission is receptive to further pilot programs and provides guidance below with respect to the essential characteristics that such pilot programs should embody.

The Commission supports the goal of gathering operational data needed to quantify the specific costs and benefits attributable to EV usage and to assign these costs and benefits to the appropriate parties. Further, the Commission supports the involvement of public utilities in helping to attain such goals. However, in order to approve the involvement of Duke and other public utilities in any pilot program, the Commission will require that pilot programs also include consideration of or as an aspect of the pilot, at a minimum, the following attributes:

- *Proper Scale and Scope*: The scale and scope of a pilot program should be set in a manner that allows the utility to test a concept at a smaller scale without incurring substantial capital costs, such that if the pilot program is successful it can then be readily deployed system-wide with more assurance that it will be economically viable.

- *Rate Design*: Suitable pilots should involve experimental rate designs and contain measures to track and measure customer response to such rates. The Commission recognizes that in the pending DEC and DEP general rate cases the utilities have proposed to study the general system-wide implementation of special rate plans for electric vehicles as part of a more comprehensive examination of overall rate design. The Commission does not believe it would prejudice that comprehensive study but would in fact be beneficial to that exercise if the utilities offered to a limited group of customers in a pilot program experimental rates to encourage or support EV use.

- *Cost-Benefit Analysis*: Detailed costs and revenues resulting from pilot programs should be tracked and reported in a way that can be used to develop future cost-benefit analyses. A cost-benefit analysis must be conducted on each program before it can be scaled beyond its pilot program size. Any large-scale implementation of piloted programs must show the ability, when scaled, to yield an overall positive system benefit net of all costs.

- *Leverage Other Funding*: Pilot programs should encourage or require the use of third-party funding (private, federal, state, municipal, grants) wherever it is available. Programs should also encourage ownership and operation partnerships that provide the greatest benefit to customers.

- *Make-ready Approach*: Duke should leverage familiarity with permitting requirements, the interconnection process, and the design, operations, and maintenance of the distribution system to efficiently identify and develop appropriate preparations for EV infrastructure.

- *Objectives, Metrics, and Verification*: Each pilot program should have clearly defined goals, metrics for evaluating performance, and a verification process.

- *Reporting and Stakeholder Engagement*: Duke must engage stakeholders throughout the term of any pilot and report on the performance of the programs on at least an annual basis.

Specifically applying the above criteria to the proposed EV Charging Management programs, the Commission supports incentives where appropriate to collect data or encourage behavior with clear financial benefits to the system. The Commission, however, is not persuaded that the rebate programs as proposed at this time satisfy the criteria set forth herein above. While the Commission acknowledges that the results of the ET Pilot will inform future rate design, Duke presently has sufficient information-gathering tools to test pilot ET rates using data already gathered. For example, when asked at the hearing about the potential for obtaining charging data from the approximately 14,000 EVs currently registered in North Carolina, witness Reynolds acknowledged that existing EV owners are a viable data resource, tr. vol. 1, 31, and therefore could be used for this purpose. Other such resources include data from Duke's AMI meters, data from Duke's and its affiliates' own EV fleets, other affiliates' EV pilot programs, and the resources from other states identified by the Public Staff.

The Commission notes that Duke agrees in its comments to commit to an evaluation, measurement, and verification (EM&V) analysis of the impact of all segments of the ET Pilot to ensure that the goals of the Pilot are met and to engage an expert in how the programs can be evaluated. Duke also offers in its Settlement Agreement with ChargePoint to convene a series of collaborative meetings with stakeholders to present interim ET Pilot progress and results and to gather feedback on the ET Pilot. Lastly, Duke agrees to use the learnings from the ET Pilot in any efforts to evaluate and develop effective rate design offerings for customers with EVs.

With the foregoing in mind, the Commission finds good cause to direct Duke and the Public Staff to convene a collaborative stakeholder process to provide input and feedback on potential future pilot programs and to require that the stakeholder process be organized and conducted as follows:

(1) Duke and the Public Staff shall equally share the responsibility for the implementation, organization, and leadership of the collaborative;

(2) All parties to the present dockets shall be invited to engage in full participation in the collaborative;

(3) The first meeting of the collaborative shall be held within one month of the date of this Order, and subsequent meetings shall be held, at a minimum, every two months thereafter, with the purpose of developing pilot programs that are consistent with the foregoing requirements; and

(4) Any pilot programs developed by Duke through this collaborative process shall be filed with the Commission for review and approval not later than six months following the date of this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That the Public Level 2 Charging program, as proposed, and a limited version of the Duke proposed Multifamily Dwelling Charging, Direct Current Fast Charging, and EV School Bus Charging programs, as described herein, are approved;

2. That the remaining programs proposed as part of the ET Pilot and the Companies' Settlement Agreement with ChargePoint are not approved; and

3. That Duke and the Public Staff shall organize and facilitate a collaborative stakeholder process in compliance with the guidelines provided in this Order and file any stakeholder developed pilot programs within six months of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of November, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief 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	))))	ORDER DENYING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR MERCHANT GENERATING FACILITY

HEARD: Wednesday, December 18, 2019, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Friesian Holdings, LLC:

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

Steven J. Levitas, Kilpatrick Townsend & Stockton, LLP, 4208 Six Forks Road, Suite 1400, Raleigh, North Carolina 27609

For Duke Energy Progress, LLC:

Jack E. Jirak, Associate General Counsel, Duke Energy Corporation, P.O. Box 1551 / NCRH 20, Raleigh, North Carolina 27602

For North Carolina Sustainable Energy Association:

Peter Ledford and Benjamin Smith, North Carolina Sustainable Energy Association, 4800 Six Forks Road Suite 300, Raleigh, North Carolina 27609

For North Carolina Clean Energy Business Alliance:

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

For the Using and Consuming Public:

Tim R. Dodge and Layla Cummings, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

ELECTRIC MERCHANT PLANTS – CERTIFICATE

BY THE COMMISSION: On November 7, 2016, in Docket No. SP-8467, Sub 0, the Commission issued Friesian Holdings, LLC (Friesian or the Applicant), a certificate of public convenience and necessity (CPCN) pursuant to N.C. Gen. Stat. § 62-110.1(a) and Commission Rule R8-64 for the construction of a 75-MW solar photovoltaic electric generating facility to be located on Leisure Road near Academy Road, Laurinburg, in Scotland County, North Carolina (the Facility). In addition, the Commission accepted the registration of the Facility as a new renewable energy facility pursuant to Commission Rule R8-66.

On August 2, 2018, Friesian filed a request to amend the CPCN previously issued for the Facility.

On May 15, 2019, in both Docket Nos. SP-8467, Sub 0 and EMP-105, Sub 0, Friesian filed a statement requesting that the Commission (1) allow Friesian to withdraw the requested amendment; and (2) consider a new application for a CPCN pursuant to Commission Rule R8-63 in Docket No. EMP 105, Sub 0, for this same facility (the Application). The Commission treated this filing as a request to cancel the previously issued CPCN in Docket No. SP-8467, Sub 0. And, on June 14, 2019, the Commission issued an order allowing withdrawal of the requested amendment, canceling the previously issued CPCN, and closing the docket.

Also on May 15, 2019, Friesian prefiled the direct testimony and exhibits of Brian C. Bednar, Friesian's Manager and Authorized Agent, as well as President of Birdseye Renewable Energy, LLC (Birdseye), an affiliate of Friesian. The testimony explained that Friesian seeks approval to build a 70-MW solar PV facility beginning in the summer of 2023, and that the Facility would interconnect with the electric transmission system owned by Duke Energy Progress, LLC (DEP or Duke).

On May 31, 2019, the Public Staff filed a Notice of Completeness stating that it had reviewed the application as required by Commission Rule R8-63(d) and considered the Application to be complete. In addition, the Public Staff requested that the Commission issue a procedural order.

On June 13, 2019, the Commission issued an Order that, *inter alia*, scheduled hearings, established a procedural schedule for the filing of petitions to intervene and of testimony, and directed Friesian to publish notice of the public hearing once a week for four consecutive weeks, beginning at least 30 days prior to July 26, 2019.

On June 21, 2019, the North Carolina Electric Membership Corporation (NCEMC) filed a petition to intervene, which the Commission granted on July 2, 2019. On July 18, 2019, NCEMC filed comments.

On July 18, 2019, Friesian filed the final, executed confidential Power Purchase Agreement (PPA) to replace the draft, confidential PPA that was originally filed as Confidential Exhibit No. 7 with the Application on May 15, 2019.

On July 23, 2019, DEP filed a petition to intervene, which the Commission granted on August 2, 2019.

On July 29, 2019, the North Carolina Sustainable Energy Association (NCSEA) filed a petition to intervene, which the Commission granted on August 20, 2019.

On August 1, 2019, the Public Staff filed a motion identifying and asking that the Commission consider several prehearing legal issues and seeking the establishment of a date for the filing of prehearing briefs and the suspension of the schedule for the filing of expert witness testimony. The intervention of the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On August 5, 2019, the North Carolina Clean Energy Business Alliance (NCCEBA) filed a petition to intervene, which the Commission granted on August 16, 2019.

On August 5, 2019, the Commission issued an Order suspending the procedural schedule previously established and allowing the parties to file briefs addressing the following legal 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.[G.S.] § 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 Application the costs associated with the approximately $227 million dollars in transmission network upgrades and interconnection facilities 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, Friesian, the Public Staff, DEP, and NCCEBA each filed briefs; on September 9, 2019, Friesian, the Public Staff, DEP, and NCCEBA and NCSEA (jointly) each filed reply briefs.

On October 3, 2019, the Commission issued an Order scheduling oral argument whereat the parties were to address the issues noted in the Commission's August 5 Order, and, additionally, the question 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.

On October 25, 2019, the Commission issued an interlocutory order notifying the parties of the Commission's preliminary decision on the legal issues addressed by the parties' prehearing briefs and at oral argument. In sum, the Commission "agree[d] 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," and noted that "[t]he Commission's final order on the merits of the CPCN application [would] include the Commission's full discussion and conclusions relevant to these issues . . . ." The Commission further ordered the procedural schedule resumed, setting a hearing for the purpose of receiving expert witness testimony for December 18, 2019, at 10:00 a.m., and allowing for the timely filing of supplemental direct testimony and exhibits.

On November 26, 2019, Friesian filed the supplemental direct testimony and corresponding exhibits of three witnesses: Charles Askey, Senior Project Manager in the Power Engineering & System Planning Group at Timmons Group; Brian Bednar; and Rachel Wilson, Principal Associate with Synapse Energy Economics, Inc. (Synapse).

On December 6, 2019, the Public Staff filed the joint testimony and exhibits of Evan Lawrence and Dustin Metz, both engineers in the Electric Division.

Also on December 6, 2019, and in lieu of testimony, DEP filed statement of position letters from Stephen De May, North Carolina President of Duke Energy, and Jack E. Jirak, Associate General Counsel for Duke Energy Corporation. These filings were unsworn and have not been subjected to cross-examination.

Statements of position letters were also filed in this docket by Helen Livingston in her individual capacity; Maggie Clark, Senior Manager of State Affairs, Solar Energy Industries Association (SEIA), on behalf of SEIA; James McDougald, Economic Development Director for the Town of Maxton; Ray Britt, Chairman of the Bladen County Board of Commissioners; and Bob Davis, Chair of the Scotland County Board of Commissioners.

On December 12, 2019, Friesian filed the rebuttal testimony and exhibits of witnesses Askey, Bednar, and Wilson.

This matter came on for hearing on December 18, 2019. Friesian presented the testimony and exhibits of witnesses Askey, Bednar, and Wilson, who testified as a panel. The Public Staff presented the testimony and exhibits of witnesses Lawrence and Metz, who also testified as a panel. None of the other intervenors, including DEP and NCEMC, presented witnesses or testimony, or offered any exhibits.

On December 20, 2019, the Public Staff filed a copy of the presentation given by the National Renewable Energy Laboratory (NREL) on its Carbon-free Resource Integration Report on the Duke System given to the Carbon Reduction Stakeholder Group hosted by the North

Carolina Department of Environmental Quality (DEQ) at the Nicholas Institute on December 11, 2019, as a late-filed exhibit.

On January 8, 2020, DEP filed a response to a Commission question related to the increase in the cost of the network upgrades as a late-filed exhibit.

On February 10, 2020, Friesian, the Public Staff, and NCSEA separately filed proposed orders and briefs.

On April 16, 2020, DEP filed a supplemental late-filed exhibit.

On April 20, 2020, Friesian filed a Motion for Expedited Consideration of its Application.

On April 21, 2020, the Commission issued a Notice of Decision.

Based upon consideration of the pleadings, testimony, and exhibits received into evidence, the items upon which the Commission takes judicial notice, and the record as a whole, the Commission makes the following

FINDINGS OF FACT

1. Friesian is a limited liability company registered to do business in the State of North Carolina. Friesian is an affiliate of Birdseye Renewable Energy, LLC.

2. Friesian's Application for a CPCN authorizing the construction of a 70-MW solar photovoltaic electric generating facility to be located on approximately 544 acres in Scotland County, North Carolina (the Facility), was filed pursuant to N.C.G.S. § 62-110.1 and Commission Rule R8-63.

3. The Application has sufficiently completed State Clearinghouse Review.

4. While the Facility would be located in DEP service territory, the output from the Facility would be wheeled by DEP to NCEMC pursuant to a power purchase agreement (PPA) between Friesian and NCEMC for the sale of the output and renewable energy certificates (RECs) generated by the Facility. Friesian fails to sufficiently establish that the Facility's output is necessary to meet any of NCEMC's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance requirements to be given substantial weight in support of the Application.

5. Friesian fails to support the beneficial economic impacts that it asserts would flow to Scotland County with either sufficient detail or specific attribution to the Facility to be given substantial weight in support of the Application.

6. In its determination of need the Commission may consider factors other than Friesian's plan for the output of the Facility, including the long-term energy and capacity needs in the State and region, as well as system reliability concerns.

7. It is undisputed that the energy and capacity provided by the Facility are not otherwise needed to support any immediate or future load growth in the DEP East Balancing Area or the southeastern region of the State.

8. The placement of additional uncontrolled solar generating capacity in a region of the DEP system that currently contains significant existing solar generation may increase and exacerbate system operational issues already being faced by DEP's system operators and would provide minimal contribution to meeting winter peak load conditions.

9. The Facility proposes to interconnect with DEP's transmission network and begin commercial operation in December 2023. Friesian and DEP executed a Large Generator Interconnection Agreement (LGIA) in June 2019. Capacity on the transmission lines to which the Facility would connect is currently constrained, and load flow models indicate that additional generating capacity cannot be added in the pertinent portion of DEP's service territory without requiring substantial upgrades, including the construction of a proposed new 34.5-kV collector station and 230-kV breaker station, and the reconductoring of 63 miles of DEP transmission lines.

10. The generating plant of the Facility is estimated to cost $100 million to construct. The transmission network upgrades required to support the Facility (Network Upgrades) are estimated to cost $223.5 million to construct.

11. It is appropriate for the Commission to consider the total construction costs of a facility, including the cost to interconnect and to construct any necessary transmission network upgrades, when determining the public convenience and necessity of a proposed new generating facility.

12. The use of the levelized cost of transmission (LCOT) provides a benchmark as to the reasonableness of the transmission network upgrade cost associated with interconnecting a proposed new generating facility.

13. The potential for the Network Upgrades to lead to additional proposed generating capacity to be placed in service is too uncertain and speculative to be given substantial weight in support of the Application.

14. The Synapse Report does not provide sufficient evidence that either the Facility or the associated Network Upgrades would provide quantifiable ratepayer savings, emission reductions, or other environmental or health benefits.

15. Until such time as compliance with Executive Order 80 and the policy recommendations in the Clean Energy Plan are fully investigated and considered in the context of Duke's integrated resource planning (IRP) process, any benefits associated with the construction of the Facility and the Network Upgrades are not sufficiently known and measurable to be given substantial weight in support of the Application.

16. Given the uncertainties stated in Findings of Fact Nos. 13, 14, and 15, more deliberate and comprehensive planning is the appropriate method, at this time, to identify and plan for upgrades to the system that are in the public interest.

17. The General Assembly, in enacting House Bill 589 (HB589), intended to establish a process to identify and support the location of additional renewable generation in the State in a manner that is most cost-effective to ratepayers.

18. Reform of the North Carolina Interconnection Procedures to involve the clustering of projects for interconnection study purposes is consistent with N.C.G.S. § 62-110.1(b) and is appropriate to help ensure that interconnection customers are receiving appropriate pricing signals to locate their projects in the most cost-effective interconnection locations, as well as to reduce congestion that otherwise results when the need for significant upgrades is identified.

APPLICABLE LEGAL STANDARD

Article 6 of Chapter 62 provides, in relevant part, that

> no public utility or other person shall begin the construction of any . . . facility for the generation of electricity to be directly or indirectly used for the furnishing of public utility service . . . without first obtaining from the Commission a certificate that public convenience and necessity requires, or will require, such construction.

N.C.G.S. § 62-110.1(a). In considering whether to approve a facility proposed under this statute the Commission must focus upon an element of public need for the facility and emphasize a policy that favors the orderly expansion of electric generating capacity that both creates a reliable and economical power supply *and* prevents the costly overbuilding of generation resources. *See State ex rel. Utils. Comm'n v. Empire Power*, 112 N.C. App. 265, 279-80, 435 S.E.2d 553, 561 (1994); *State ex rel. Utils. Comm'n v. High Rock Lake Ass'n*, 37 N.C. App. 138, 140-41, 245 S.E.2d 787, 790, *disc. rev. denied*, 295 N.C. 646, 248 S.E.2d 257 (1978).

That said, the North Carolina Supreme Court has long recognized the flexibility of the public convenience and necessity standard, requiring that the distinct facts of each case be considered:

> In our opinion, these statutes give the Commission not only the authority but impose upon it the duty to pass upon [the matter] and to determine whether or not it is in the public interest . . . .
>
> The doctrine of convenience and necessity has been the subject of much judicial consideration. No set rule can be used as a yardstick and applied to all cases alike. This doctrine is a relative or elastic theory rather than an abstract or absolute rule. The facts in each case must be separately considered and from those facts it must be determined whether or not public convenience and necessity require [the action].

State ex rel. Utils. Comm'n v. Casey, 245 N.C. 297, 302, 96 S.E.2d 8, 12 (1957) (citation and quotation marks omitted).

Finally, the decision of whether to grant or deny a CPCN must rest upon substantive evidence; it cannot rest on speculation or sentiment. *Cf. Howard v. City of Kinston*, 148 N.C. App. 238, 246, 558 S.E.2d 221, 227 (2002). The burden is on the applicant to provide this substantive evidence and demonstrate that the CPCN should be granted.

The Commission has carefully considered and weighed all the evidence and arguments presented in this proceeding, and concludes that Friesian has failed to show that the Application is in the public interest and that public convenience and necessity requires that the Application be granted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

These findings of fact are informational, procedural, and jurisdictional in nature and are not in dispute.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-8

The evidence supporting these findings of fact is found in the Application; the testimony of Friesian witnesses Askey, Bednar, and Wilson; and the joint testimony of Public Staff witnesses Lawrence and Metz.

Witness Bednar testified that Friesian entered into a power purchase agreement (PPA) with NCEMC on July 15, 2019, under which NCEMC will purchase all of the Facility's output. Witness Bednar also stated that the Facility will provide a significant number of renewable energy certificates (RECs) for use by NCEMC to comply with North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS or Senate Bill 3), which among other things requires rural electric cooperatives and municipal electric suppliers to meet a 10% REPS requirement. Witness Bednar testified that these plans for the sale of the Facility's energy and capacity demonstrate its need. Tr. vol. 2, 21-22. Witness Bednar further offered the economic development impact to the communities of Scotland County, and other Tier 1 counties, as an additional reason to support granting the CPCN. Tr. vol. 2, 37.

In their joint testimony, Public Staff witnesses Lawrence and Metz asserted that having an executed PPA does not in-and-of-itself sufficiently demonstrate that a merchant generating facility is entitled to a CPCN; need is instead to be evaluated on a case-by-case basis. Tr. vol. 3, 116. They testified that the Commission had previously held that it is reasonable to require substantial evidence of the need for a merchant generating facility, and that a flexible standard for demonstrating need was appropriate, but that an executed PPA or other contractual agreement was not necessary. *Id.* at 114. Witnesses Lawrence and Metz further stated that the Public Staff has previously recommended approval of CPCN applications in the absence of a signed PPA. Tr. vol. 3, 165. They acknowledged that they were not aware of any prior case in which the Public Staff has taken the position that it is taking in the present case, that the PPA contract itself is not a sufficient demonstration of need. *Id.* at 174. They further acknowledged that they were not aware of any Commission precedent to this effect. *Id.* at 165.

Public Staff witnesses Lawrence and Metz also acknowledged that DEP's integrated resource plan (IRP) indicates a capacity need over the planning period but argued that "one cannot assume that any generation resource can be added to, and complement, the existing system just because reserve margins fall below a particular threshold," noting that the IRP is a capacity expansion model used to solve for multiple constraints and scenarios to help determine the generation resources needed to meet long-term load in the most economical manner. *Id.* at 117-18. They further testified that the DEP system is winter peaking and winter planning, and while DEP's IRP demonstrates a need for dependable capacity to meet winter peak loads, the addition of intermittent, non-dispatchable renewable solar facilities will provide minimal contribution to winter morning peak loads and limited value to grid operators. *Id.* at 118-19.

Witnesses Lawrence and Metz also testified that DEP had not previously identified the transmission lines in question as needing upgrades due to reliability issues in any of the reports issued by the NC Transmission Planning Collaborative (NCTPC). Witness Metz acknowledged that transmission in the area where the Facility is proposed to be located has been identified as constrained, meaning that it has limited ability to accommodate new generating resources, but argued that being constrained was not necessarily disadvantageous. He noted that constrained areas can occur throughout a utility's system, and the NERC standards require transmission planners to evaluate risk in order to target critical areas in the electrical grid for investments. Tr. vol. 4, 22-23.

Friesian witness Askey offered the results of an analysis conducted by the Timmons Group of the system impact study developed by DEP to evaluate the impacts to the system of adding the Friesian capacity at the proposed location. He interpreted the study to show that multiple line segments are loaded at over 95% or 100% of their contingency ratings, triggering the need for upgrades. He further noted that, even without additional generating capacity being added, the system is within five to ten percent of the contingency loading levels under the scenarios modeled, indicating that the system in that area is at the upper end of its operational range. Tr. vol. 2, 67-70.

Witness Askey stated that DEP's system is technically NERC-compliant but he believes that deferral of the Network Upgrades will leave the transmission system in southeastern North Carolina in a "maxed-out state" and could leave the grid more vulnerable to disruption than it would be if the Network Upgrades are constructed. *Id.* at 79-83.

Discussion and Conclusions

Commission Rule R8-63(b)(3) requires an applicant for a CPCN for a merchant plant to provide "a description of the need for the facility in the state and/or region, with supporting documentation." Additionally, before the Commission can award a CPCN for a generating facility, N.C.G.S. § 62-110.1(d) requires the Commission to consider the "applicant's arrangement with other electric utilities for interchange of power, pooling of plant, purchase of power and other methods for providing reliable, efficient, and economical electric service." Thus, a sufficient demonstration of need for a proposed new generating facility is fundamental to the Commission's decision of whether public convenience and necessity requires granting the CPCN.

As noted above, that demonstration generally is to focus on dual concerns: the orderly expansion of generation and capacity, and the prevention of costly overbuilding. And the required demonstration of need may also differ depending on whether the CPCN is sought for a generating facility by a regulated utility, a small power producer seeking to sell its output to the utility as a qualifying facility (QF), or a merchant generating facility.[1] To this end, the flexibility of the CPCN standard necessarily includes analyzing the need for the merchant generating facility to be placed not just within the State but a certain region, as well as evaluating whether the applicant has accurately assessed and met wholesale market needs. All said, it is "the duty [of the Commission] to pass upon [the project] and to determine whether or not it is in the public interest . . . ." *Casey*, 245 N.C. at 302, 96 S.E.2d at 12; *see also* Order Granting Certificate, *Application of Rowan Generating Company, LLC, for a Certificate of Public Convenience and Necessity to Construct a Generating Facility in Rowan County, North Carolina*, No. EMP-3, Sub 0, 8 (N.C.U.C. Oct. 12, 2001) (stating that the Commission is "mindful that issues regarding the appropriate amount of merchant plant generation in the State remain to be decided.").

Friesian witness Bednar testified that the PPA with NCEMC is dispositive on the issue of need. As it traditionally has, the Commission affords some weight to the existence of the PPA as a demonstration of need. But the Commission agrees with Public Staff witnesses Metz and Lawrence that while having "[a]n executed PPA does demonstrate at least in part the potential [financial] viability of the project, . . . [it] is not, in and of itself, a sufficient criterion on which to base a recommendation for approval or disapproval of a CPCN." Tr. vol. 3, 116. Rather, the existence of a PPA or other plans for sale of energy and capacity from the facility must be balanced against other existing factors that may be considered when determining the overall need for the Facility. As evidenced by prior Commission orders, the question may include the facility's

[1] For example, an electric public utility under Rule R8-61(b)(1) must, in addition to demonstrating need for a facility in its IRP, submit additional information supporting the need for the facility related to resource and fuel diversity, information on energy and capacity forecasts, and an explanation of how the proposed facility meets the identified energy and capacity needs. For QFs, the Commission has previously stated that federal law has essentially established a "public need" for their construction, based on the obligations established under the Public Utility Regulatory Policies Act of 1978 (PURPA) requiring a utility to purchase the output from a QF at its avoided cost rates. *See* Order on Motion to Dismiss, *Application of Empire Power Company for a Certificate of Public Convenience and Necessity Pursuant to G.S. 62-110.1(a)*, No. SP-91, Sub 0 (N.C.U.C. Apr. 23, 1992). Because of the federally mandated purchase of the output of QFs, when Friesian first applied for a CPCN to develop and operate the Facility as a QF, the Commission did not consider the need for the Facility because the federal mandate takes the place of (or amounts to) need.

Similarly, considerations relating to the total costs of the Friesian project, discussed at greater length later in this order, were not operative in the Commission's determination of Friesian's application in Docket No. SP 8467, Sub 0. PURPA directs that for a QF which will sell its energy and capacity to a regulated utility, the total costs for the QF's project are immaterial so long as the price the regulated utility will pay to the QF for energy and capacity do not exceed the utility's own "avoided cost." If the total costs of the project cannot be recouped by the QF from charges that are calculated based on the purchasing utility's avoided cost, then any resulting loss is essentially invisible when viewed from the perspective of the total electricity generation, transmission, and distribution system.

compliance with State or federal laws,[1] the provision of lower-cost, economic power alternatives,[2] or whether the generation addition helps address reliability and service quality issues.[3]

Friesian witness Bednar also testified that the Facility would provide a significant number of renewable energy credits (RECs) for use by NCEMC to comply with North Carolina's Renewable Energy and Energy Efficiency Portfolio Standards (REPS). Friesian witness Wilson similarly stated that "NCEMC likely analyzed its . . . renewable generation supply needed for REPS compliance . . . and concluded that contracting with Friesian was a cost-effective way to meet those needs." But neither witness Bednar nor witness Wilson provided any corroborating evidence that the RECs that would be procured by NCEMC from Friesian are necessary for this purpose or that NCEMC has an actual need for RECs.

Relatedly, on July 18, 2019, NCEMC filed an unsworn comment in this docket, stating that "the [Friesian] Project — specifically, the parties' execution of the Project PPA — will simultaneously advance NCEMC's pursuit of BEF [a set of 'strategic business objectives' called 'A Brighter Energy Future'] and further its ability to achieve REPS compliance." But the letter filed by NCEMC is merely a restatement of NCEMC's three business objectives. It does not set out a specific, or even a general, strategy for attaining "A Brighter Energy Future," it contains no programs, policies, goals, objectives, or metrics, and it does not speak at all to NCEMC's targets for REPS compliance. In short, neither NCEMC nor Friesian presented sufficient evidence supporting the general assertion that the RECs generated by the Facility will facilitate NCEMC's compliance with its REPS obligations or meet its business objectives. *See* N.C.G.S. § 62-65(a).

Moreover, an examination of both NCEMC's most recent, verified NC REPS Compliance Plan, filed August 29, 2019, in Docket No. E-100, Sub 163, and the database in the North Carolina Renewable Energy Tracking System (NC-RETS) — both of which the Commission took judicial notice, *see* Tr. vol. 3, 78 — show that NCEMC has fully satisfied its RECs requirements without the Facility and, thus, does *not* need the Facility's RECs to achieve or maintain compliance for the near future. Indeed, the Friesian PPA, which was executed in June of 2019, is not referenced or identified in NCEMC's REPS Compliance Plan. Based on the foregoing, the Commission is not

[1] *See, e.g.*, Order Granting Certificate and Accepting Registration of New Renewable Facility, *Application of Atlantic Wind, LLC, for a Certificate of Public Convenience and Necessity*, No. EMP-49, Sub 0 (N.C.U.C. May 3, 2011; Order Granting Certificate of Public Convenience and Necessity with Conditions, *Application of Duke Energy Carolinas, LLC, for Approval of a Solar Photovoltaic Distributed Generation Program*, No. E-7, Sub 856 (N.C.U.C. Dec. 31, 2008).

[2] *See, e.g.*, Order Issuing Certificate of Public Convenience and Necessity with Conditions, *Application of Duke Energy Carolinas, LLC, for a Certificate of Public Convenience and Necessity to Construct a 402-MW Natural Gas-Fired Combustion Turbine Generating Facility in Lincoln County, North Carolina*, No. E-7, Sub 1134 (N.C.U.C. Dec. 7, 2017).

[3] *See, e.g.*, Order Granting Certificate with Conditions, *Application of Duke Energy Progress, LLC, for a Certificate of Public Convenience and Necessity to Construct a Microgrid Solar and Battery Storage Facility in Haywood County, North Carolina*, No. E-2, Sub 1127 (N.C.U.C. Apr. 6, 2017); Order Granting Certificate of Public Convenience and Necessity with Conditions, *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*, No. E-2, Sub 1185 (N.C.U.C. May 10, 2019).

persuaded that the generation by the Facility of a significant number of RECs for use by NCEMC for REPS compliance demonstrates a need for the Facility in the region.

Friesian witness Bednar testified that the construction of the Facility will result in the creation of jobs and tax revenue in Scotland County. However, when the Commission pressed witness Bednar to provide support for the economic impact calculations, he was unable to do so. *See* Tr. vol. 3, 87-89.

On the topic of general need for new generating facilities in this region, the Commission notes that **[BEGIN CONFIDENTIAL[**

[END CONFIDENTIAL].

To this end, the Commission recognizes, as testified to by Public Staff witnesses Lawrence and Metz, that DEP's IRP indicates a capacity need over the planning period. However, the Commission also notes the Public Staff's testimony that "one cannot assume that *any* generation resource can be added to, and complement, the existing system just because reserve margins fall below a particular threshold[.]" *Id.* at 117 (emphasis added). Rather, the IRP involves a capacity expansion model that solves for multiple system constraints and scenarios ultimately to determine the generation resources needed to meet load projections over the planning period. As Public Staff witness Metz and Lawrence testified, and as Friesian witness Askey acknowledged on cross-examination, the DEP system is winter peaking and winter planning at this time, and while DEP's IRP demonstrates a need for additional capacity to meet winter peak loads, the addition of uncontrolled, intermittent solar generation will provide minimal contribution to winter morning peak loads and limited value to grid operators. *Id.*; *see also* Tr. vol. 2, 176-79. Thus, the Commission is persuaded by the Public Staff that the capacity need identified in DEP's IRP does not support a determination of need for the Facility.

Importantly, the Applicant has identified no reliability or service quality concerns necessitating the Facility. To the contrary, Friesian witness Bednar acknowledged that DEP states that the continued addition of solar generation in the DEP East Balancing Area would instead exacerbate existing reliability challenges and increase the potential for NERC compliance issues. *See* Tr. vol. 2, 165-67. He also acknowledged that DEP's growing experience in managing operationally excess energy and increasingly steep ramping requirements as additional unscheduled and uncontrolled solar generation is integrated into the system will increase the likelihood of emergency curtailments of solar generation in DEP. *Id.* at 167-69.

In sum, while the Commission gives some weight to the PPA as support for the need for the Facility, the Commission balances this evidence against the Applicant's failure to substantiate either the need for RECs generated by the Facility or its economic impacts, that the Facility is not likely to satisfy the capacity need identified in the DEP IRP, and that the Facility is not proposed to address reliability or service quality concerns and may actually exacerbate existing reliability and service quality issues being experienced in the DEP East Balancing Area. Based on the weight of the evidence, the Commission concludes that the Applicant has failed to demonstrate a need for the Facility.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-12

The evidence supporting these findings of fact is found in the Application and the testimony of Friesian witnesses Bednar and Wilson, and the joint testimony of Public Staff witnesses Lawrence and Metz.

According to the Application and as Friesian witness Bednar testified, the Facility would be constructed on approximately 544 acres in Scotland County, North Carolina, southwest of Laurinburg. The Facility would interconnect with the DEP transmission grid through a newly constructed 34.5-kV collector station directly adjacent to the DEP Laurinburg-Bennettsville 230-kV transmission line. *See also* Application Exhibit 5. Witness Bednar testified that the Facility is expected to have a useful life of approximately 20 years and that the estimated construction costs for the generating plant are approximately $100 million. Tr. vol. 2, 19-21.

Witness Bednar also described the factors that Birdseye uses to identify the lowest cost sites for solar development in the State, including the Facility. He listed several favorable attributes present in the southeastern region of the State, including the abundance of open, flat land, low population density, proximity to transmission infrastructure, and favorable geology for the low-cost installation of solar foundations. Given these attributes, the region has already attracted significant solar development and is now severely constrained, with no new generation resources able to be added without substantial upgrades to DEP's transmission system. Tr. vol. 2, 24-34.

Public Staff witnesses Lawrence and Metz testified that under the Large Generator Interconnection Agreement (LGIA) executed between DEP and Friesian in June 2019 (*see* Public Staff's August 26, 2019 Prehearing Brief, Exhibit 1), the Facility requires approximately $4 million in Interconnection Facilities that are directly attributable to the Facility, including a new 230-kV breaker station. In addition, the Facility will also require extensive transmission network upgrades (Network Upgrades). The Network Upgrades are currently estimated to cost $223.5 million, and include reconductoring 63 miles, and uprating 10 miles, of DEP transmission lines. *Id.; see also* Tr. vol. 3, 122.

Witnesses Lawrence and Metz explained that the LGIA obligates Friesian to pay for the Interconnection Facilities, to provide DEP with security for the associated Network Upgrades, and to pay DEP's invoices for costs incurred to construct the Network Upgrades. Upon commercial operation and under Duke's Open Access Transmission Tariff (OATT), however, Friesian would be entitled to receive repayment from DEP of the entire balance of the Network Upgrades cost plus interest at the monthly interest rates posted by FERC. Under the LGIA, specifically, DEP must repay Friesian via lump sum cash repayment by the earlier of either DEP's next North Carolina general rate case or by December 31, 2027, with interest.

DEP then would seek to include approximately 30% of the costs in its FERC formula rates charged to its wholesale customers, resulting in an increase in transmission rates of approximately 10% above the average annual rate on a pro-rata basis across all of DEP's wholesale transmission customers. *Id.* at 101, 124-25. At the retail level; the remaining 70% of the costs would be recovered from DEP's retail customers through base rates, with 60% recovered through North Carolina base rates and 10% recovered through South Carolina base rates. Based on calculations completed by DEP, this cost recovery would result in an order of magnitude increase in retail rates for DEP's North Carolina retail customers of approximately 0.5% per year on a pro-rata basis. *Id.* at 124-26.

Public Staff witnesses Lawrence and Metz stated that the Public Staff generally evaluates interconnection and system upgrade costs in other merchant and utility CPCN proceedings. In several of those proceedings Public Staff noted some concerns regarding certain transmission-related costs but did not ultimately recommend denial of the CPCNs. Witnesses Lawrence and Metz also testified that for a number of these previously reviewed merchant generating facilities, however, several were proposed to be sited in the service territory of Dominion Energy North Carolina (DENC). *Id.* at 126-28.

Public Staff witnesses Lawrence and Metz argued that a levelized cost of transmission (LCOT) analysis provides a tool to evaluate the reasonableness of the upgrade costs associated with certain generating technologies. They cited to a 2019 study by Lawrence Berkeley National Laboratory (LBNL Study) that reviewed interconnection cost studies for renewable energy facilities on a nationwide basis, doing so by calculating LCOT value. Witnesses Lawrence and Metz explained that LCOT value is calculated by dividing the annualized cost of the required new transmission assets over the typical transmission asset lifetime by the expected annual generator output in MWh, with the outputs presented in a $/MWh value. The LBNL Study compiled transmission upgrade costs for 303 projects in the MISO region (amounting to a total of 49 GW); 338 projects in PJM (amounting to a total of 64 GW); and another 2,399 projects from various locations as reported to EIA. *Id.* at 129-30; *see also* Lawrence/Metz Exhibit 2.

In terms of solar generating facilities, the LBNL Study found that network upgrade costs for solar projects in MISO averaged $56/kW, with an LCOT value of $1.56/MWh; in PJM they averaged $116/kW, with an LCOT value of $3.22/MWh; and in the other locations (from the EIA data) they averaged $103/kW, with an LCOT value of $2.21/MWh. Witnesses Lawrence and Metz testified that, by comparison, the cost of the Network Upgrades is $3,186/kW, with an LCOT value of $62.94/MWh. Lawrence and Metz also compared the LCOT value for Friesian with that of other merchant generators in North Carolina for which the Commission had issued CPCNs. The LCOT values for the NTE Kings Mountain (Docket No. EMP-76, Sub 0) and NTE Reidsville (Docket No. EMP-92, Sub 0) facilities were significantly lower than the LCOT value projected for Friesian at $0.33/MWh and $0.92/MWh respectively. Tr. vol. 3, 130-33.

In rebuttal, Friesian witness Wilson testified that the LCOT analysis conducted by the Public Staff compared an individual project to average values presented by total volumes of renewable generation derived from large data sets. She further indicated that the Public Staff's calculation of LCOT for Friesian should be adjusted to include all of the projects that are behind Friesian in the interconnection queue and thus the Public Staff should have summed the total number of MW associated with those projects into its analysis, as well as the transmission costs associated with those projects. Witness Wilson testified that, if an additional 1,561 MW of projects that are interdependent on the Network Upgrades were included in the calculation, the cost of the Network Upgrades would fall within the range of the LBNL Study. Tr. vol. 2, 113-16.

Witness Wilson also testified that the Regional Energy Deployment System (ReEDS), developed by the National Renewable Energy Laboratory (NREL), considers generation and transmission capacity costs in its capacity-expansion model in order to minimize busbar and system-level costs for electric-sector planning purposes. Based on the 2018 Standard Scenarios presented by the ReEDS model, North Carolina in an optimized scenario could add another 900 MW of solar above current levels and associated transmission necessary for integration by 2022. *Id.*

Likewise, Friesian witness Askey testified that the Public Staff's LCOT analysis failed to consider additional generation that would use and benefit from the Network Upgrades. Witness Askey also stated that there are significant differences in LCOT calculations for Friesian compared to those for regional transmission organizations (RTOs) like MISO and PJM, which are regulated by FERC and outside of any state regulatory compact. In the context of RTOs, costs associated with transmission upgrades to accommodate new generation may be evaluated as part of system-wide baseline upgrades, as network improvements, and as directly assigned costs, and that the cost allocation may vary as a result of the different assignment of costs. Therefore, he concluded, it is difficult for any entity other than the RTO itself to determine the LCOT for a generating facility interconnecting to the grid. Witness Askey thus testified that comparing the LCOT for the Network Upgrades provides little discernable value. Tr. vol. 2, 91-92.

Upon questioning, however, witness Askey acknowledged that the largest transmission network upgrade that a merchant facility has accepted responsibility for within PJM was $125 million and that the project involved a gas-fired facility. Witness Askey indicated that a solar facility within PJM would not accept financial responsibility for network upgrades in the range of $425 million even under the model that subsequent projects coming online would contribute to the cost. Tr. vol 3, 83-84.

Discussion and Conclusions

The Commission may consider all costs that are required to construct a proposed electric generating facility, including the cost to construct the generating plant as well as the cost to construct interconnection facilities and network upgrades, when considering an application for a CPCN pursuant to N.C.G.S. § 62-110.1 and Commission Rule R8-63. To this end, the Commission, when evaluating whether public convenience and necessity requires granting the CPCN in this case, will consider the total construction cost of the Facility, which includes the cost of the generating plant, the interconnection facilities, and the Network Upgrades.

The plain language of N.C.G.S. § 62-110.1 authorizes the Commission to consider all costs associated with the construction of the proposed generating facility. Specifically, the statue provides that, "[a]s a condition for receiving a certificate, the applicant shall file an estimate of *construction costs in such detail as the Commission may require* . . . and no certificate shall be granted unless the Commission has approved the estimated construction costs *and* made a finding that construction will be consistent with the Commission's plan for expansion of electric generating capacity." N.C.G.S. § 62-110.1(e) (emphases added). When the language of a statute is clear and unambiguous it must be given its plain and definite meaning. *Carolina Power & Light Co. v. City of Asheville [(CP&L I)]*, 358 N.C. 512, 518, 597 S.E.2d 717, 722 (2004).

Nothing in the statute delineates or otherwise limits which costs that the Commission may consider when evaluating an application for a CPCN. *See Midrex Techs., Inc., v. N.C. Dep't of Revenue*, 369 N.C. 250, 258, 794 S.E.2d 785, 792 (2016) (courts must "give effect to the words actually used in a statute and should neither delete words used nor insert words not used . . . .") (citation and quotation marks omitted). Thus, the Commission may consider all costs of a proposed facility, including those necessary to interconnect to the system and transmit the energy produced by the generating facility, i.e., all costs that are necessary to make useful operation of the facility at the outset. *See High Rock Lake Ass'n*, 37 N.C. App. at 140-41, 245 S.E.2d at 790 (the statute "directs the Utilities Commission to consider . . . the construction costs *of the project* before granting a certificate of public convenience and necessity for a new facility") (emphasis added).

The CPCN statute also obligates the Commission to analyze "the long-range needs for expansion of facilities . . . including its estimate of the probable future growth of the use of electricity, the probable needed generating reserves, the extent, size, mix and general location of generating plants and arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission and other arrangements with other utilities and energy suppliers to *achieve maximum efficiencies for the benefit of the people of North Carolina* . . . ." N.C.G.S. § 62-110.1(c) (emphasis added); *see also State ex rel. Utilities Com'n v. Carolina Power & Light Co. [(CP&L II)]*, 359 N.C. 516, 522, 614 S.E.2d 281, 285 (2005). And, "[i]n acting upon any petition for the construction of any facility for the generation of electricity, the Commission shall take into account the applicant's arrangements with other electric utilities for interchange of power, pooling of plant, purchase of power and other methods for providing *reliable, efficient, and economical electric service*." N.C.G.S. § 62-110.1(d) (emphasis added). Without consideration of the total construction cost of a proposed generating facility, the Commission cannot ensure that any build-out will represent maximum efficiencies and provide cost-effective electric service for citizens and other ratepayers. *See CP&L II*, 359 N.C. at 522, 614 S.E.2d at 285.

Additionally, assuming *arguendo* that the language of the CPCN statute is ambiguous, the Commission concludes that the legislature must have intended that the Commission would consider all costs triggered by the siting of a generating plant. The "best indicia of that intent" includes "what the act seeks to accomplish." *Diaz v. Div. of Soc. Servs.*, 360 N.C. 384, 387, 628 S.E.2d 1, 3 (2006) (citation omitted); *accord CP&L I*, 358 N.C. at 518, 597 S.E.2d at 722 ("the reviewing court must construe the statute in an attempt not to defeat or impair the object of the statute . . . ."). The very reason the CPCN statute was enacted was to stop the costly overexpansion of facilities to serve areas that did not need them. *See High Rock Lake Ass'n*, 37 N.C. App. at 140-41, 245 S.E.2d at 790; *see also State ex rel. Utils. Comm'n v. Empire Power*, 112 N.C. App. 265, 280, 435 S.E.2d 553, 561 (1994).

This conclusion is further informed when reading "[the CPCN] standard *in pari materia* with N.C.G.S. § 62-2 which contains ten [now twelve] specific policies . . . ." *Empire Power*, 112 N.C. App. at 274, 435 S.E.2d at 557. Several of these policies support that the legislature intends the Commission to encourage cost-efficient siting of generation facilities, and thus that the Commission has the authority to consider all costs borne as a result of that siting decision.

Friesian and intervenors NCCEBA and NCSEA have argued that even if the Commission has the statutory authority to consider the transmission upgrade costs, any such consideration is preempted by the Federal Power Act, 16 U.S.C.S § 791a, et seq. (FPA or the Act), and FERC's jurisdiction under that Act. In brief, these parties contend that because FERC has sole jurisdiction to determine the manner in which the costs of the Network Upgrades will be paid and then assigned to various parties and interests, the Commission is thereby forbidden to consider both *the fact* that the Facility will cause such costs to be incurred and the *magnitude* of such costs in themselves or proportionally.

It is well-established that states have traditionally assumed jurisdiction and authority over the generation of electricity, and thus over decisions addressing the need for and the siting of all necessary facilities. *See Pacific Gas & Elec. Co. v. State Energy Resources Conservation and Development Comm'n*, 461 U.S. 190, 194, 75 L. Ed. 2d 752, 760 (1983); *see also FERC v. Elec. Power Supply Ass'n [(EPSA)]*, 577 U.S. ___, ___, 193 L. Ed. 2d 661, 668 (2016). Similarly, "states have traditionally assumed all jurisdiction [over the approval or denial of] permits for the siting and construction of electric transmission facilities." *Piedmont Environmental Council v. FERC*, 558 F.3d 304, 310 (4th Cir. 2009), *cert. denied*, 558 U.S. 1147, 175 L. Ed. 2d 972 (2010); *see also Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 75 F.E.R.C. ¶ 61,080, P.433 n.543, 61 Fed. Reg. 21,540, 21,626 n.543 (1996) ("Among other things, Congress left to the States authority to regulate generation and transmission siting."). Indeed, the FPA only gives FERC the authority to interfere with this jurisdiction — i.e., delegates to FERC federal jurisdiction which preempts state jurisdiction — when the transmission both falls inside a national interest corridor and one of five "carefully drawn" circumstances applies. *See* 16 U.S.C.S. § 824p(b)(1); *see also Piedmont*, 558 F.3d at 313-14.

Even in a traditionally state-occupied realm, however, Congress may supersede state or local action either explicitly or implicitly. *See generally Pacific Gas*, 461 U.S. at 203-04, 75 L. Ed. 2d at 765; *see also New York v. FERC*, 535 U.S. 1, 18, 152 L. Ed. 2d 47, 62 (2002); *Anderson v. Sara Lee Corp.*, 508 F.3d 181, 191 (4th Cir. 2007). There, State action is preempted only to the extent that it: "actually conflicts with federal law"; makes compliance with both federal and state law impossible; or "stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress." *Pacific Gas*, 461 U.S. at 204, 75 L. Ed. 2d at 765 (citations and quotation marks omitted). And on review there is no "presumption one way or the other." *New York*, 535 U.S. at 18, 152 L. Ed. 2d at 63.

The FPA gives FERC the

> exclusive authority to regulate the sale of electric energy at wholesale in interstate commerce . . . [and] assigns to FERC responsibility for ensuring that "[a]ll rates and charges made, demanded, or received by any public utility for or in connection

> with the transmission or sale of electric energy subject to the jurisdiction of the Commission . . . shall be just and reasonable . . . ."

Hughes v. Talen Energy Marketing, LLC, 578 U.S. ___, ___,194 L. Ed. 2d 414, 419-20 (2016); *see also* 16 U.S.C. § 824(b)(1). "This statutory text . . . unambiguously authorizes FERC to assert jurisdiction over two separate activities — transmitting and selling [the power in the wholesale market]." *New York*, 535 U.S. at 19-20, 152 L. Ed. 2d at 63; *see also* 16 U.S.C. § 824(a).

The FPA also gives FERC jurisdiction over "any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of [FERC]" as well as "any rule, regulation, practice, or contract affecting such rate, charge, or classification." 16 U.S.C. § 824e(a). Admittedly, this jurisdiction might well encompass allocating the cost of transmission facilities to retail ratepayers once those facilities have been constructed. *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 63-64 (D.C. Cir. 2014) (finding that this "does not interfere with the traditional state authority that is preserved by Section 201" of the FPA); *see also Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 F.E.R.C. ¶ 61,103 (2003).

But nothing in the FPA extends this jurisdiction over, and precludes, the States' consideration of the cost of required transmission network upgrades when determining the most prudent and cost-effective locations for generating facilities to be placed or whether the generation is needed in the first instance. *See Virginia Uranium, Inc. v. Warren*, 139 S. Ct. 1894, 1907, 204 L. Ed. 2d 377, 389 (2019) (typically, "any '[e]vidence of pre-emptive purpose,' whether express or implied, must . . . be 'sought [and found] in the text and structure of the statute at issue."); *see also id.* at 1900, 204 L. Ed. 2d at 381 (". . . it is our duty to respect not only what Congress wrote but, as importantly, what it didn't write."). Nor do any of FERC's regulations or orders decidedly extend the same. *See generally Hillsborough County v. Automated Med. Labs., Inc.*, 471 U.S. 707, 717, 85 L. Ed. 2d 714, 724 (1985) ("We are even more reluctant to infer pre-emption from the comprehensiveness of [agency] regulations than from the comprehensiveness of statutes . . . .").

Rather, "the law places beyond FERC's power, and leaves to the States alone . . . control over in-state facilities used for the generation of electric energy." *Hughes*, 578 U.S. at ___, 194 L. Ed. 2d at 420 (citations omitted). This authority includes deciding *where* to site those generation facilities and "[t]here is little doubt that . . . state public utility commissions or similar bodies are empowered to make the initial decision regarding the need for power." *Pacific Gas*, 461 U.S. at 205-06, 75 L. Ed. 2d at 760 (citations omitted); *see also Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009) ("State and municipal authorities retain the right to forbid new entrants from providing new capacity . . . to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from the Commission"; it is the "consumer-constituents of state commissions . . . [that] will appropriately bear the costs of that decision, including paying more for system reliability from older and less efficient units."). This authority thus necessarily includes consideration of all the information that might impact that siting decision — including the construction of transmission system upgrades required to accommodate that additional generation.

FERC implicitly recognized the same in Order No. 888. *See* Order No. 888, 61 Fed. Reg. at 21,626 n.543. FERC further declared that its Final Rule "[was] not [to] affect or encroach upon state authority in such traditional areas as the authority over local service issues, including reliability of local service . . . [and] utility generation and resource portfolios." *Id.* at n.544 (cited in *New York*, 535 U.S. at 24, 152 L. Ed. 2d at 66).

Later, FERC issued Order No. 1000 in an effort to manage electric transmission grids on a regional level. *See Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 F.E.R.C. ¶ 61,051 (2011). Therein, FERC recognized that States could continue to regulate electric transmission lines, explicitly stating:

> We acknowledge that there is longstanding state authority of certain matters that are relevant to transmission planning and expansion, such as matters relevant to siting, permitting, and construction. However, nothing in this Final Rule involves an exercise of siting, permitting, and construction authority. The transmission planning and cost allocation requirements of this Final Rule . . . are associated with the processes used to identify and evaluate transmission system needs and potential solutions to those needs. In establishing these reforms, the Commission is simply requiring that certain processes be instituted. This in no way involves an exercise of authority over those specific substantive matters traditionally reserved to the states, including integrated resource planning, or authority over such transmission facilities. For this reason, we see no reason why this Final Rule should create conflicts between state and federal requirements.

Order No. 1000 at ¶ 107; *see also MISO Transmission Owners v. FERC*, 819 F.3d 329, 336 (7th Cir. 2016) (it was a "proper goal" for FERC "to avoid intrusion on the traditional role of the States in regulating the siting and construction of transmission facilities"), *cert. denied*, 137 S. Ct. 1223, 197 L. Ed. 2d 463 (2017). It makes little sense then that the Commission would continue to have authority over the siting, permitting, and construction of all generation and transmission facilities — including for integrated resource planning purposes — but would not have the authority to consider all information that might impact the propriety of siting and constructing those facilities.

That conclusion is also consistent with and supported by language in the Supreme Court's decision in *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 90 L. Ed. 2d 943 (1986). Though the question now before the Commission presents in a different procedural guise than the ratemaking proceedings that were at issue in *Nantahala*, Justice O'Connor's discussion of the distinction between a decision to purchase power and the price at which such power is purchased is nevertheless pertinent. In holding that this Commission impermissibly invaded FERC's exclusive jurisdiction when it attempted to establish retail rates that did not recognize and accept the FERC-determined allocation of low-cost "entitlement power," the Court noted that such a case was *not* the same as an unconstrained decision whether or not to enter into a transaction involving the purchase of power in the first instance, stating:

> Without deciding this issue, we may assume that a particular *quantity* of power procured by a utility from a particular source could be deemed unreasonably

> excessive if lower-cost power is available elsewhere, even though the higher-cost power actually purchased is obtained at a FERC-approved, and therefore reasonable, *price.*

Id. at 972, 90 L. Ed. 2d at 958 (emphasis in original). In other words, because the utilities in *Nantahala* were bound by FERC's allocation of available low-cost "entitlement power," they were not free to purchase a greater amount of such low-cost power, in preference to higher cost power from other wholesale suppliers, and consequently this Commission was likewise bound by such allocation in setting retail rates for such utilities.

The important distinction between the facts in *Nantahala* and those presented to the Commission here is that the decision posed to the utilities in *Nantahala* — that is, whether, and how much power, to purchase — was constrained by FERC determinations. In this case, however, the question to be decided is not so constrained. FERC has not ordered, directly or indirectly, that the Friesian facility be constructed, that it be sited at any particular location in the state, that its energy and capacity be sold to any particular purchaser, that such energy and capacity be sold at any particular price, or any other of the numerous other details of the Friesian project. Whether it is in the public convenience and necessity that Friesian be constructed at all is conceptually the same type of decision as that embodied in the above-quoted passage from *Nantahala.*

Two years after the *Nantahala* decision, in *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354, 101 L. Ed. 2d 322 (1988), the Supreme Court reiterated that distinction, quoting from *Nantahala* and elaborating thus:

> Appellees seek to characterize this case as falling within facts distinguished in *Nantahala.* Without purporting to determine the issue, we stated in *Nantahala*: "[W]e may assume that a particular *quantity* of power procured by a utility from a particular source could be deemed unreasonably excessive if lower-cost power is available elsewhere, even though the higher-cost power actually purchased is obtained at a FERC-approved, and therefore reasonable, *price* . . . ." As we assumed, it might well be unreasonable for a utility to purchase unnecessary quantities of high-cost power, even at FERC-approved rates, if it had the legal right to refuse to buy that power. But if the integrity of FERC regulation is to be preserved, it obviously cannot be unreasonable for MP & L to procure the particular quantity of high-priced Grand Gulf power that FERC has ordered it to pay for. Just as Nantahala had no legal right to obtain any more low-cost TVA power than the amount allocated by FERC, it is equally clear that MP & L may not pay for less Grand Gulf power than the amount allocated by FERC.

Mississippi Power, 487 U.S. at 373-74, 101 L. Ed. 2d at 340 (internal citation omitted). Once again, the utility's decision whether, and how much power, to purchase was legally constrained by FERC's determination of the wholesale power allocation and the wholesale rates. Thus, in both *Nantahala* and *Mississippi Power* the matter of whether the affected utility would or would not, or should or should not, enter into an arrangement or agreement governed by FERC-established rules and orders had already been decided before the state regulatory bodies considered those arrangements in ratemaking proceedings.

The two cases stand for the proposition that a state cannot, through its retail ratemaking, attempt to nullify or vary an action taken or cost incurred by the regulated utility in consequence of and in compliance with FERC rules and determinations. By contrast, the question now before this Commission is, in substance, the same as would have been the case if the Mississippi Public Service Commission, cognizant of likely or anticipated FERC policy and practice, had decided that a CPCN should not be granted to permit Mississippi Power & Light Co. to participate in the joint construction of the Grand Gulf nuclear power plant.[1] And, accordingly, both *Nantahala* and *Mississippi Power* support the determination that whether or not power shall be procured at all — in this case by means of the construction of a new generating facility — is not limited by FERC's jurisdiction to determine the price of such power or the assignment of the costs of procuring it.

That said, no party disputes that southeastern North Carolina exhibits many attributes favorable for the development of solar generating facilities and that those attributes have resulted in significant solar development in that region. As a result, however, the transmission infrastructure in that portion of the DEP system is approaching a tipping point where additional generation in certain portions of the system will require significant upgrades to the network. The Commission shares the concern of the Public Staff regarding the appropriateness of siting additional generation in this region, in this manner, and at this time, given the significant cost implications for the provision of electric service in North Carolina.

This concern is especially prudent given a comparison of the cost of comparable new solar energy facilities. To this end, the Commission views the LCOT analysis performed by the Public Staff as a benchmark of the reasonableness of the Network Upgrades relative to other similar transmission investments made to interconnect generating facilities in North Carolina.[2] And the LCOT analysis performed by the Public Staff shows just how unprecedented the cost of the Network Upgrades are to costs realized on a national basis. To that end, the Commission accepts that the calculated LCOT value of the Network Upgrades is $62.94 MWh, and far surpasses — it is 19.5 times higher than — the next highest mean range value reported by the Study for solar generating facilities calculated in MISO, PJM, or more broadly by EIA.[3]

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[1] It is of interest that the Mississippi Public Service Commission had originally granted a CPCN to Mississippi Power & Light Co. to participate in the Grand Gulf nuclear plant development before any of the matters in controversy in the case took place. This fact was noted by the Supreme Court as part of the factual background for the case, *see Mississippi Power*, 487 U.S. at 358-59, 364, 101 L. Ed. 2d at 330-31, 333-34, but there is nothing in the Court's decision to suggest that the Mississippi commission would have been intruding on FERC's jurisdiction had it simply chosen to deny the CPCN due to uncertainties or concerns about the ultimate costs that would have been incurred by or assigned to Mississippi Power & Light Co.

[2] The Commission notes that the LBNL Study specifically states that the cost information in the report is generalized and should be used to inform high-level decisions and directives. LBNL Study at 27.

[3] The Commission also rejects, as Friesian argues, that uncertain future generation must be included when calculating the Friesian Facility's LCOT value. To the contrary, the LCOT analysis provides a useful comparison of actual incurred costs with the proposed transmission upgrade costs associated with specific generation resources. The LCOT analysis does not evaluate the loading of existing lines and whether they are fully subscribed, but instead provides a high-level comparison of costs that have been incurred around the nation to interconnect solar facilities. To assume that those lines can, or will certainly, accommodate additional generation resources goes beyond the scope of the LBNL Study. Insofar as the Commission were to accept DEP's estimate that the Network Upgrades will facilitate another 1,000 MW of generator interconnections (for a total of 1,070 MW) — which, as discussed further below, is

The Commission has also reviewed the other North Carolina merchant plant projects discussed by Public Staff witnesses Lawrence and Metz, as well as the cost estimates for other Duke transmission projects as reported by the North Carolina Transmission Planning Collaborative (NCTPC) for the last 14 years — of which the Commission took judicial notice at the hearing. *See* Tr. vol. 3, 77-78. During those 14 years, the typical Duke transmission project had a mean cost in the range of $20 to $42 million, and the two most expensive Duke transmission projects were estimated to cost $85 million (Richmond to Fort Bragg Woodruff Street 230 kV line) and $95million (Orchard Tie 230/100 kV tie station). The NTE Reidsville combined cycle plant's interconnection costs were estimated at $53 million. At an estimated construction cost of $223.5 million, the Network Upgrades would far and away be the single costliest transmission project in North Carolina in recent times, perhaps the most expensive ever.

No party through the time of the hearing — or any time prior to the filing of the parties' proposed orders — challenged the accuracy of the estimated $223.5 million plus interest.[1] Further,

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uncertain — the cost would still be a relatively high $208/kW, still close to double the highest average cost of any of the groupings studied.

Likewise, the Commission agrees with the Public Staff that DEP's estimate overlooks the likelihood that these future projects will themselves require additional costly upgrades. Without studying the future projects comprehensively as part of a group or cluster, however, how much additional generation would be able to interconnect, and whether additional upgrade costs could impact the LCOT calculations, is uncertain.

[1] On January 8, 2020, DEP filed a late-filed exhibit. That filing describes the basis for the almost doubling of costs from the initial estimate of $116 million: "a more detailed understanding of the scope and . . . developed using the Company's [recently] updated cost and scheduling systems." DEP also indicates therein that already-experienced increases in labor costs and costs due to environmental compliance factored into the $223.5 million estimate. In addition, a contingency of approximately $39.5 million was included in that estimate. January 8, 2020 DEP Late-Filed Exhibit, 1.

On April 16, 2020, DEP filed a supplemental late-filed exhibit. That filing sought to revise DEP's earlier estimate from $223.5 million to $187.3 million. The filing explains the basis for the $37.1 million reduction as driven primarily by: lowered vendor rates; material assumption variances, and the use of a wood product matting in lieu of a composite material in some locations; and reduction of the earlier contingency amount — which was itself $39.5 million.

But neither of these late-filed exhibits were subject to examination nor is it clear through what witness they might be introduced. Indeed, not only did no party, including DEP, choose to call an appropriate witness at the hearing to explain the bases for these now three estimates, the late-filed exhibits themselves are merely letters from Duke's Associate General Counsel, who was neither a witness in this case nor was ever likely to be one. Rather than assuage the Commission, the various swings in the estimated cost of the transmission network upgrades raise further concern.

Appendix B of the LGIA indicates that Duke will provide Friesian with "Class III Estimates" of the project's costs; the January 8, 2020 DEP Late-Filed Exhibit, however, describes its estimate as a "Class 4 estimate"; and the April 16, 2020 DEP Supplemental Late-Filed Exhibit describes its estimate as a Class 3 Estimate. It is the Commission's understanding that no matter whether the current estimate is a Class 3 or 4 type estimate, these types of estimates have low accuracy. Even the lower of the two most recent estimates allows, as a Class 3 Estimate, for the possibility that actual costs could be understated as much as 30 percent. In other words, the most recent estimate could still increase another $56 million — i.e., more than the most recent downward adjustment, and to a number higher still than the accepted $223.5 million estimate.

All said, whether $187.3 million, $223.5 million, or more, the Commission's analysis and ultimate conclusion would remain the same.

no party presented a witness, such as a Duke transmission expert, who could credibly address the potential that the actual cost for the Network Upgrades could be substantially more or less than $223.5 million, let alone be cross-examined. As such, the Commission accepts this estimate for the purposes of its decision making.

Also, the Commission is concerned about the potential for the Network Upgrades cost to increase further. Witness Bednar admitted this possibility. He discussed that labor competition for high voltage transmission and station work might well drive various costs even higher. *See* Tr. vol. 2, 39 (noting a "dramatic increase in interconnection costs"), 41-42 ("from 2017 to today, my sources within the [Engineering, Procurement, and Construction] community [state] that it's not unusual for high voltage and transmission costs to have risen 30 to 40 percent broadly, nationwide, based . . . upon shortages of general construction capacity . . . ."), 44-45. So too might an increase in material costs — witness Bednar candidly testified to a "5 to 10 percent increase . . . on [the price of] cable and wire" every six months for "a cumulative in two and a half years of [a] 35 percent" cost increase. *Id.* at 45. He also acknowledged that each of Birdseye's other projects had seen their estimated interconnection costs increase. *Id.* at 46.

As such the Commission believes that the current estimated cost — already significant — could be understated. This belief also rests upon the scale and complexity of the upgrades in question, which, according to witness Bednar, includes crossing the Cape Fear River four times, *see id.* at 40 & 47; the work having to occur during 12 weeks each year when the existing transmission lines in question can be taken out of service, where a single weather event, such as a hurricane or late snow or ice storm, has the potential to substantially delay the work, *id.* at 66-68, 124; and the short window — by the 2023 in-service date — in which to complete the upgrades. Each concern risks driving the cost higher.

The Commission recognizes and acknowledges the jurisdiction of the FERC with respect to the allocation of the costs associated with interconnecting a merchant generating facility such as the Facility. Nevertheless, the cost of the Network Upgrades dwarfs the costs of the generating plant, and the scale of the costs associated with the Facility relative to the size and projected revenue from the Facility raises concerns regarding economic viability of the project. Indeed, as witness Bednar admitted, the Homer and Fair Bluff projects — proposed generating facilities in the interconnection queue behind, and thus interdependent with, the Facility — would not be viable were they responsible for paying for the Network Upgrades. *See* Tr. vol. 2, 137-38.

For these reasons, the Commission concludes that siting the Facility in this region of the State and at the particular point of interconnection is not consistent with the requirements of N.C.G.S. § 62-110.1(d) for the provision of "reliable, efficient and economical electric service."

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-15

The evidence supporting these findings of fact is found in the testimony of Friesian witnesses Askey, Bednar, and Wilson, and the joint testimony of Public Staff witnesses Lawrence and Metz.

Friesian witness Bednar testified that he expects "that the Friesian upgrades will be utilized by a minimum of 1,000 MW of later queued generation in the constrained area" of DEP's system in which the Facility proposes to interconnect. Tr. vol. 2, 42. Witness Bednar further testified that he believes the Network Upgrades are necessary to support significant addition of solar generation resources in North Carolina due to the importance of the constrained area to further solar development in the State. Tr. vol. 2, 45. He stated that the Network Upgrades represent the only "immediately-actionable" proposal to address transmission-related constraints in this region of the State. Tr. vol. 2, 43-44.

Friesian witness Askey testified that data request responses from Duke identified approximately 1,561 MW that is currently interdependent on the Network Upgrades and that DEP stated that the "Friesian upgrades will at least partially facilitate the interconnection of more than 1,000 MW of additional generation." Tr. vol. 2, 171-72. He conceded, however, that there may well be additional transmission network upgrades that are required to interconnect those other projects.

Friesian witness Wilson testified that the LCOT analysis conducted by the Public Staff is deficient in that it fails to take into consideration all of the projects that are behind Friesian in the interconnection queue. Witness Wilson testified that, if an additional 1,561 MW of projects that are interdependent on the Network Upgrades were included in the calculation, the cost of the Network Upgrades would fall within the range of the LBNL Study. Tr. vol. 2, 113-16. Friesian witness Askey similarly testified that the Public Staff's LCOT analysis failed to consider additional generation that would use and benefit from the Network Upgrades. Tr. vol. 2, 91-92.

With respect to transmission constraints, Friesian witness Askey testified that, based on information provided by DEP, substantial transmission network upgrades will be needed to accommodate any new generating resources that are planned for the southeastern region of North Carolina. He testified that one of DEP's two 1235-MW combined cycle plants that are being evaluated for siting in Cumberland County is interdependent on and would benefit from the Network Upgrades. Tr. vol. 2, 266. He also stated that even if the DEP facilities being studied are not built, the Network Upgrades will be required to connect new generation resources in the State. *Id.* at 175.

In their joint testimony, Public Staff witnesses Lawrence and Metz acknowledged that Q399, the queue position of the second proposed combined cycle plant under consideration by DEP, is interdependent upon a significant portion of the Network Upgrades, as well as upon other significant transmission upgrades that may be required. The Public Staff refused to assign significant weight to the potential for the Network Upgrades to reduce the upgrade costs associated with future planned generation, however, because such an analysis is "heavily dependent upon future IRPs showing a continued need for additional capacity, contingencies such as the completion of the [Atlantic Coast Pipeline], as well as DEP demonstrating that [the] Q399 [project] is in the public interest in a CPCN application, as opposed to other resource alternatives." Tr. vol. 3, 132-33.

Friesian witness Wilson testified that a substantial buildout of new renewable energy resources is in the public interest for North Carolina ratepayers, notwithstanding the cost upon those ratepayers of the $223.5 million in Network Upgrades needed to support the Facility. In her direct testimony, witness Wilson cited a study in which she was a primary author entitled *North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan* (Synapse Report), included in her testimony as Exhibit RW-1. In support of her argument, witness Wilson testified that the type of generating portfolio recommended by the Synapse Report results in least cost energy and has additional benefits in the form of reduced air emissions and improved public health. Tr. vol. 2, 98. The Synapse Report was previously presented in Docket No. E-100, Sub 157 in response to the Commission's solicitation of comments on the 2018 IRPs submitted by DEP and Duke Energy Carolinas (collectively, Duke). The Synapse Report presents a "Clean Energy scenario" that models a significant addition of solar and storage resources to the Duke portfolio over the 15-year IRP planning horizon. *Id.* at 99-100. In the Clean Energy scenario, by 2033, there are 14 gigawatts (GW) of solar capacity and almost 6 GW of battery capacity added in the Duke service territories. *Id.* at 120.

Witness Wilson stated that the Clean Energy scenario represents a savings of almost $8 billion in terms of the net present value of revenue requirements over the duration of the 15-year planning period. Witness Wilson calculated that the health benefits of the Clean Energy scenario range from $195 to $440 million by 2024, due to avoided emissions of sulfur dioxide, oxides of nitrogen, and particulate matter. *Id.*

Witness Wilson also admitted that the Synapse Clean Energy scenario does not include the costs of any new transmission or upgrades to existing transmission required to interconnect renewables, including the Friesian project. *Id.* at 104, 120; *see also* Tr. vol. 3, 22-23. Further, she stated:

> My study is an economic one, and it looks at the least cost resource alternative to a comparison portfolio, which in this case is Duke's 2018 IRP, and determines that additional solar and storage resources are to the benefit of ratepayers. *It doesn't look at where those renewables are sited, [or] costs that it might take to integrate them*, and those costs are going to change over time, certainly.

Tr. vol. 3, at 25-26 (emphasis added).

Public Staff witnesses Lawrence and Metz explained that Governor Cooper's Executive Order 80 (EO80) states that North Carolina will strive to reduce greenhouse gas emissions (GHG) by 40% below 2005 levels by 2025. *Id.* at 133. EO80 further required DEQ to develop a Clean Energy Plan for the State. The Clean Energy Plan set a goal to reduce electric sector GHG emissions by 70% below 2005 levels by 2030 and obtain carbon neutrality by 2050. The Plan states that "NC's values such as electricity affordability, equity, and reliability should be fully considered." *Id.* at 134-35.

Friesian witness Wilson stated that achieving the goals of the DEQ Clean Energy Plan to reduce carbon emissions by 70% from 2005 levels by 2030 will be difficult if no additional solar resources can be interconnected in the areas dependent on the Network Upgrades. Tr. vol. 2, 108. She also testified that in order to achieve the types of emissions reductions that are being contemplated by the State of North Carolina, projects like Friesian must move forward. Tr. vol. 3, 26.

However, witnesses Lawrence and Metz testified that the Clean Energy Plan stated that the State is already on track to meet the goals of EO80. Regarding the current trend in the State's emissions, the report states:

> NC has already reduced significant amounts of GHG emissions from the electric power sector. The State's Clean Smokestacks Act, REPS, PURPA and market drivers have decarbonized the electric power sector at a faster pace than many other states. According to the most recent statewide inventory, GHG emissions from the electric power sector have declined 34% relative to 2005 levels. These reductions have been achieved in the absence of explicit carbon policies in the State. DEQ estimates that with full implementation of HB589, the GHG reduction level from the electric power sector will reach roughly 50% by 2025 and remain at this level out to 2030.

Id. at 134.[1]

Witness Metz also testified that DEP is working with the National Renewable Energy Laboratory (NREL) to determine the quantity of renewables that can interconnect to the system. Tr. vol. 4, 83. Witness Metz explained that there are two phases of the study:

> Phase 1 scope quantify the amount of carbon free electricity, estimate a curtailment[, ramping,] and system flexibility limits, evaluate its shifts, and daily seasonal net load timing supply. There's another phase coming because Phase 1 did not consider unit commitment and economic dispatch[,] system stability cost[,] or transmission impacts. Phase 2 will address those concerns.

Id. at 104.

Discussion and Conclusions

The Commission has carefully considered the evidence presented by the Applicant as to secondary benefits that would follow the construction of the Facility and concludes that, at this time, those benefits are too speculative and uncertain to support a determination that granting the CPCN is in the public interest.

Friesian asserts that the Network Upgrades would enable significant, additional future generating capacity to interconnect to the DEP network. Friesian points to a data request response received from Duke as support that the Network Upgrades would enable the interconnection of more than 1,000 MW of additional solar generation in the southeastern portion of North Carolina and the northeastern portion of South Carolina. *See* Tr. vol. 2, 122-23, 170-71; Tr. vol. 3, 136. The Duke data request response also states that "[b]ased on the assessment completed by DEP for

[1] *See also* Tr. vol. 3, Official Exhibits, Public-Staff Frisian Panel Cross Examination Exhibit 7, DEQ Clean Energy Plan, at 267.

interconnection requests received through September 30, 2017, there are 108 interconnection requests totaling 1,561 MW that have been identified as being interdependent on the upgrades assigned to Friesian." Friesian witness Wilson also testified that the Network Updates might facilitate the interconnection of an additional 900 MW of future solar generation as well. *See* Tr. vol. 2, 114-15.

But whether the additional generation will be developed and placed in service is subject to many variables in addition to interconnection cost. And there is nothing in the record from which the Commission can conclude that any one of the proposed generating facilities, much less all of them, will actually be constructed and placed in service. Without more, the Commission concludes that whether the Network Upgrades are or will be needed to enable significant, additional future generation is too uncertain to be given significant evidentiary weight by the Commission.

Friesian's assertion also includes that the Network Upgrades would facilitate and reduce the cost of DEP-owned proposed generating capacity. While the Load, Capacity, and Reserves Tables in DEP's 2018 IRP and 2019 IRP Update indicate the addition of two facilities with approximately 1,300 MW of combined cycle capacity in 2025 and 2027, these resources are undesignated at this time. DEP has not yet taken steps to determine resource alternatives to meet the undesignated need shown in the IRP, such as issuing a request for proposals (RFP) or filing a CPCN application for the facilities. DEP itself did not cite this benefit in its December 6, 2019 letters to the Commission, and DEP did not provide a witness in this proceeding to explain whether the Network Upgrades would benefit any planned DEP facilities.

Further, DEP's interconnection queue report dated January 27, 2020, shows that 12 interconnection requests are pending for a total of 14,560 MW of new, DEP-owned gas-fired generating plants, while DEP's IRP shows that the Company plans to build a much smaller amount of new gas-fired generation, 7,852 MW, through 2034. DEP does not have a CPCN granted or an application for a CPCN or any such plant pending. After reviewing the queue report, the Commission concludes that DEP has as yet no firm plans to build a gas-fired generator in Cumberland County but is instead studying several alternative sites throughout its territory, including sites in Wake, Wilson, Person, and Johnston Counties. The Commission therefore concludes that whether the Network Upgrades are or will be needed in the near term for any planned or proposed DEP generating facilities to provide service to DEP customers is likewise too uncertain to be given significant evidentiary weight by the Commission.

Friesian next calls upon the Synapse Report. But its Clean Energy scenario does not model the Friesian Facility or the Network Upgrades at all, making it of limited relevance. Also, the Report's Clean Energy scenario calls for the addition of more than 14 GW of solar generating capacity and almost 6 GW of battery capacity in the DEP and DEC territories over the next 15 years. Yet, insofar as the Commission were to accept DEP's estimate, the Network Upgrades would only *partially*[1] facilitate a small fraction, some 1,000 MW, of the solar generating capacity necessary to achieve the benefits claimed by the Synapse Report. For purposes of this proceeding, witness Wilson did not quantify the estimated benefits along these narrower, more pertinent, lines. More concerning, her Clean Energy scenario fails to include the cost of transmission network

[1] *See* Tr. vol. 2, 56, 171 ("partial facilitation means that it will address the interdependencies, but there may be additional upgrades associated with those projects that [are required] to allow them to also interconnect").

upgrades in its model. If these upgrades had been contemplated, the model likely would have produced different, and less favorable, results regarding the benefits to ratepayers. For each of these reasons, the Commission must afford limited evidentiary weight to the benefits included in the Synapse Report and discussed by witness Wilson.

Friesian's reliance on the DEQ Clean Energy Plan exhibits similar shortcomings. As the Public Staff notes, the Clean Energy Plan contains several recommendations to ensure the addition of reliable and affordable energy resources. These goals are statewide goals. Importantly, according to DEQ, the State's electricity sector is currently *on pace* to meet the Governor's EO80 emissions reduction target in 2025.

The Clean Energy Plan also contains several recommendations for stakeholder processes and comprehensive planning tools to achieve its goals to add cost-effective, affordable clean energy resources to North Carolina's generating portfolio. Specifically, it states:

> DEQ will enlist assistance from academic institutions to deliver a report to the Governor by December 31, 2020, that recommends carbon reduction policies and the specific design of those policies to best advance core values—including a significant and timely decline in greenhouse gas emissions, affordable electricity rates, expanded clean energy resources, compliance flexibility, equity, and grid reliability. The report will evaluate policy designs for the following: (1) accelerated coal retirements, (2) a market-based carbon reduction program, (3) clean energy policies such as an updated REPS, an EERS Short term and clean energy standard, and a (4) a combination of these policy options.

Tr. vol. 3, Official Exhibits, Clean Energy Plan, Public Staff-Friesian Panel Cross-Examination Exhibit No. 7, 213. Relatedly, Duke is also currently working with NREL to develop a Carbon-free Resource Integration Study to analyze and quantify the impact of new renewables on the DEP and DEC systems. *See* December 20, 2020 Public Staff Late-Filed Exhibit No. 1.

In sum, the Commission concludes that the benefits alleged by the Applicant to follow the construction of the Facility are too speculative and uncertain to support a determination that granting the CPCN is in the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-18

The evidence supporting these findings of fact is found in the prehearing brief of the Public Staff, the testimony of Friesian witness Bednar, and the joint testimony of Public Staff witnesses Lawrence and Metz.

Public Staff witnesses Lawrence and Metz testified regarding the need for comprehensive system planning, including the IRP process, the integrated systems operation planning (ISOP) process being developed by the utilities, distribution system planning, and competitive bidding processes like the CPRE Program or short-term market solicitations, rather than individual CPCN applications. The Public Staff believes that as rate pressures on electric customers continue to increase, comprehensive system planning will produce more efficient, cost-effective results than the piece-meal planning and construction approach currently being used. Tr. vol. 3, 137-38.

In its prehearing brief, the Public Staff noted that, in its June 14, 2019 Order Approving Revised Interconnection Standard and Requiring Reports and Testimony, in Docket No. E-100, Sub 101 (2019 Sub 101 Order), the Commission directed 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." Prehearing brief at 11-12, quoting from 2019 Sub 101 Order at 18. The Public Staff noted the Commission's recognition of the arguments raised by Duke and others that the current serial study process was not sustainable and that comprehensive queue reform was necessary to better align the NC Interconnection Standard and Duke's FERC OATT with regard to studying projects, assigning upgrade costs, and collecting the costs of those projects. As such, the Commission found that the commitment by Duke to implement a stakeholder process to develop a group study proposal was reasonable and appropriate. *Id.*

Also in its prehearing brief, the Public Staff noted that a significant portion of the additional generating capacity that would benefit from the Network Upgrades would not be responsible for any of the network upgrade costs and that this disparity highlights the need for the queue reform measures proposed by Duke. *Id.*

Friesian witness Bednar acknowledged the benefits of comprehensive system planning but believed that deferral of the Network Upgrades is "ill-advised," noting that the timing of the IRP and ISOP processes creates risks of bringing new generation online, will result in additional study costs, and will increase the cost of the upgrades when they are ultimately constructed. Tr. vol. 2, 43. He cited the statements of position filed by Duke Energy, in which Duke stated that the need for the upgrades would not go away, and that "if the Friesian Network Upgrades are not constructed at this time, there will be a further substantial delay of any additional generating facilities in this area of DEP." *Id.* at 44, quoting from December 6, 2019, letter from Jack Jirak on behalf of DEP.

Witness Bednar testified that the Application involves unique circumstances and that the construction of the Network Upgrades will provide substantial benefits to the DEP transmission system and the State as a whole. Regarding the potential impacts of the Network Upgrades on the current queue reform efforts underway by Duke, witness Bednar testified that the Network Upgrades would minimize short-term challenges associated with Duke's queue reform plans, as well as allow for the interconnection of a substantial amount of renewable resources in the region. Tr. vol. 2, 46-47.

On cross-examination, Public Staff witness Metz stated that the Public Staff is generally supportive of a transition from the current serial queue to a grouping study model, and stated that on a going-forward basis, the grouping study approach would help to address some of the concerns raised in this proceeding. Witness Metz conceded that the transition process will be complex and that such a transition could be further delayed if the Network Upgrades are not approved. But he further stated that the transmission network upgrades required by the Facility are substantial and represent a tipping point. Tr. vol. 4, 42-47.

Discussion and Conclusions

The circumstances presented by the Facility illustrate the significant issues related to the continued development of renewable energy, as well as the implications for the electric systems, in North Carolina. As previously discussed in the Commission's 2019 Sub 101 Order, North Carolina has achieved nation-leading success in the siting and development of renewable energy generating facilities over the past decade, and the majority of the capacity added utilized existing transmission and distribution capacity on the DEP, DEC, and DENC systems. However, this success has come at a cost with the transmission system constraints in southeastern North Carolina and the system operational challenges that the utilities have begun to experience. In enacting HB589, the General Assembly both recognized these challenges and accordingly encouraged the siting of renewable energy resources in locations where the system could most efficiently accommodate them. *See* N.C.G.S. § 62-110.8(c).

The Commission recognizes the activities underway to consider and address the issues highlighted by the Facility. Both the DEQ Carbon Reduction Stakeholder Group and Phase 2 of the NREL Carbon-Free Resources Integration Study intend to analyze and quantify the impact of new renewables on the DEP and DEC systems and both are likely to result in recommendations. Similarly, there exists the promise of future queue reform that seeks to enable Duke to perform a cluster study process. *See* Order Requiring Queue Reform Proposal and Comments, *Petition for Approval of Revisions to Generator Interconnection Standards*, Docket No. E-100, Sub 101 (N.C.U.C. August 27, 2019). Each of these activities, in addition to the IRP and ISOP processes, can inform or support various long-term options being evaluated and provide a framework to identify the most cost-effective solutions. *See* N.C.G.S. § 62-110.1(d).

The Commission is unable to find sufficient support in the record for witness Bednar's assertion that the Network Upgrades are inevitable and that any delay in their construction will only result in increased costs to customers. To the contrary, the Commission instead credits the testimony of Public Staff witnesses Metz and Lawrence that the potential to defer costs may provide benefits to customers, depending on the carrying cost of capital, changes in commodity prices, and labor rates. Tr. vol. 3, 216-20. Additionally, due to technological changes, there also may be other alternatives identified that ultimately help to defer, minimize, or avoid altogether, the need for costly future network upgrades. *Id.* at 137. More importantly, the Commission sees value in deferring any decision related to upgrade of the system in the southeastern region of the State, pending the outcome of the activities underway.

Relatedly, in its October 23, 2019 Order Granting Motion to Delay in Docket No. E-100, Sub 101 (October 23 Order), the Commission specifically directed Duke to (1) file an updated version of its queue reform proposal as modified based on feedback from stakeholders, along with a redline version of the North Carolina Interconnection Procedures, or (2) notify the Commission that no modifications are needed. The October 23 Order also established a further procedural schedule, which was subsequently extended by order of the Commission in response to request by the parties, requiring parties to file comments on Duke's proposal and for Duke to file reply comments. Duke filed its proposal on May 15, 2020. The Commission recognizes the significance of the transition period in this process.

In sum, the Commission concludes that it is prudent to await the results of the work being undertaken in North Carolina on these issues and to consider the results of these studies and proposals in the context of the IRP process. The IRP process is the more appropriate forum to consider benefits associated with upgrades to the system, in addition to and in the context of reliability, resilience, and affordability.

CONCLUSION

After having carefully considered and weighed the evidence and arguments presented in this proceeding, the Commission concludes that Friesian has failed to persuade the Commission that granting the Application is in the public interest and required by public convenience and necessity and, therefore, denies Friesian's Application.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of June, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Lyons Gray did not participate in this decision.

DOCKET NO. G-9, SUB 743
DOCKET NO. G-9, SUB 776
DOCKET NO. G-9, SUB 777

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Piedmont Natural Gas	)	
Company, Inc., for Approval of Bi-Annual	)	ORDER APPROVING RATE
Adjustment of Rates Under Appendix E	)	ADJUSTMENTS EFFECTIVE
of its Service Regulations and	)	DECEMBER 1, 2020
Authorization to Discontinue the Rate	)	
Decrement Through Its Approved Tax Rider	)	

BY THE COMMISSION: On November 13, 2020, Piedmont Natural Gas Company, Inc. (Piedmont) filed an application requesting authority to (1) implement its proposed Integrity Management (IM) rate adjustments including a true-up adjustment to collect the October 31, 2020 balance in the IM Deferred Account in Schedule B, and (2) remove the rate decrement through the approved provisional tax rider which was approved in Docket No. G-9, Sub 743 and extended in Docket No. G-9, Sub 776, shown in Schedule A (Application).

The Integrity Management Rider (IMR) was approved by the Commission in Piedmont's most recent rate case proceeding in Docket No. G-9, Sub 743, in its Order Approving Stipulation, Granting Partial Rate Increase, Line 343 Revenue Rider, EDIT Riders, Provisional Revenues Rider, and Requiring Customer Notice (Rate Case Order). The IMR Mechanism requires that Piedmont file by October 31st an annual report summarizing the Integrity Management (IM) Plant Investment for the prior twelve-month period ending September 30th and the data substantiating and supporting its Integrity Management Revenue Requirement (IMRR) calculation for the next bi-annual IM Adjustment.

On October 30, 2020, Piedmont filed its projected three-year plan of IM Plant Investment that contained the computation for the proposed IMRR biannual rate adjustment, effective December 1, 2020, as required by Appendix E of Piedmont's North Carolina Service Regulations.

The proposed IM rate adjustments, expressed in dollars per dekatherm ($/dt), are as follows:

Description	Residential Rate 101	Small & Medium General Rate 102, 142 144, 152	Firm Large General Rate 103, 113, 12 T-10, T-12	Interruptible Large General Rate 104, 114
Rate Class Percentage	64.78%	30.18%	2.73%	2.31%
IMRR	$19,638,811	$9,149,418	$827,631	$700,303
IM Deferred Account Balance	$1,552,506	$723,288	$65,427	$55,361
Total Amount for recovery	$21,191,317	$9,872,707	$893,058	$755,664
Rate Case Volumes (dts)	39,305,821	32,055,951	35,121,753	29,923,758
M Increment per dt	$0.5391	$0.3080	$0.0254	$0.0253
Remove Previous Increment	($0.4112)	($0.2349)	($0.0194)	($0.0193)
Change in IM Increment per dt	$0.1279	$0.0731	$0.0060	$0.0060

On October 16, 2020, Piedmont filed a petition in Docket No. G-9, Sub 776 requesting Commission approval for (1) authorization to continue the provisional tax rider that refunded excess federal income taxes resulting from a decrease in the federal corporate income tax rate which was approved in Ordering Paragraph No. 8 of the Rate Case Order, which included corresponding interest, for a one-year period beginning November 1, 2019, and continuing through October 31, 2020 (Tax Rider) for an additional month, and (2) authorization to promptly deposit any remaining balance from the deferred regulatory liability account owed to ratepayers at the end of the one-month extension into Piedmont's All Customers Deferred Gas Cost Account. The Commission approved this request on October 27, 2020. Schedule A, filed in Docket No. G-9, Sub 777, reflects the removal of decrements as approved in that Order.

The Public Staff presented the matter at the Commission's November 30, 2020, Regular Staff Conference. The Public Staff stated it has reviewed the proposed IM rate adjustments as proposed on Piedmont's Schedule B, as well as the rate changes reflected on Schedule A, and recommended approval as filed.

Based on review of the application and the recommendation of the Public Staff, the Commission is of the opinion that the proposed IM rate adjustments as proposed on Schedule B, as well as the rate changes reflected on Schedule A, should be allowed to become effective as filed.

IT IS, THEREFORE, ORDERED as follows:

1. That Piedmont shall remove the decrement in rates approved in Docket No. G-9, Sub 743, and extended in Docket No. G-9, Sub 776, used to refund the over collection of federal income taxes through the approved provisional tax rider.

2. That Piedmont shall implement the proposed IM rate adjustments as contained in the body of this Order, including its IM Deferred Account balance as of October 31, 2020, effective for service rendered on and after December 1, 2020.

3. That Piedmont shall file revised tariffs consistent with Ordering Paragraphs 1 and 2 within five (5) days of the date of this Order.

4. That Piedmont shall give notice to its customers of the rate changes authorized by this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 2nd day of December, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. SP-8741, SUB 2
DOCKET NO. SP-8748, SUB 1
DOCKET NO. E-7, SUB 1156

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. SP-8741, SUB 2 DOCKET NO. SP-8748, SUB 1 In the Matter of Joint Petition of Cool Springs Solar LLC and Lick Creek Solar LLC for Declaratory Ruling and Other Relief DOCKET NO. E-7, SUB 1156 In the Matter of Petition of Duke Energy Carolinas, LLC, for Approval of Competitive Procurement of Renewable Energy Program	)	ORDER DENYING PETITION FOR DECLARATORY RULING AND OTHER RELIEF

BY THE COMMISSION: On March 30, 2020, Cool Springs Solar LLC (Cool Springs) and Lick Creek Solar LLC (Lick Creek or Petitioner; together with Cool Springs, Petitioners) filed a joint petition in Docket Nos. SP-8741, Sub 2, SP-8748, Sub 1, and E-7, Sub 1156 seeking a declaratory ruling from the Commission that Market Participants (MPs) shall not be required to terminate existing power purchase agreements (PPAs) as a condition of bidding into the Competitive Procurement of Renewable Energy (CPRE) Program. Further, Petitioners request that the Commission direct the CPRE Program Independent Administrator, Accion Group, Inc. (Accion or IA), to reverse its disqualification of Petitioners' proposals from Tranche 2 of the CPRE Program.

On April 8, 2020, Duke Energy Carolinas, LLC (DEC; together with Duke Energy Progress, LLC (DEP), Duke), filed a response in opposition to the petition in Docket No. E-7, Sub 1156.

On April 17, 2020, Petitioners filed a reply in support of the petition.

On May 15, 2020, Petitioners filed a statement and amended petition noting that Cool Springs "no longer seeks to participate in CPRE Tranche 2 and no longer seeks relief from the Commission in this proceeding." The amended petition is identical in all respects to the original petition save for the removal of Cool Springs.[1]

[1] On September 25, 2020, Lick Creek filed a Motion for Expedited Consideration, and on September 30, 2020, Accion filed a Response. These pleadings raise no new substantive issues and are noted here for completeness.

SUMMARY OF THE PLEADINGS

Amended Petition of Lick Creek

In its petition Lick Creek identifies itself as a special-purpose entity organized for the development of a solar photovoltaic (PV) generating facility in Stokes County, North Carolina, with a nameplate capacity of 50 MW_{AC} (the Project). The Project is a qualifying facility (QF) pursuant to Title II of the federal Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3134 (PURPA), and has been granted a certificate of public convenience and necessity under Commission Rule R8-64. Lick Creek further has a signed Interconnection Agreement with DEC, pursuant to which it is already making payments for "Interconnection Facilities and Upgrades," and Lick Creek notes that the Project does not require significant upgrades in order to interconnect safely and reliably to DEC's system.

Lick Creek states that the Project has a five-year avoided cost PPA with DEC pursuant to PURPA which was executed on or around September 6, 2019 (PURPA PPA). The PURPA PPA "requires Duke to purchase the Project's energy and capacity at avoided cost rates calculated as of the date the Project established a Legally Enforceable Obligation (LEO) under PURPA, and implementing regulations." Amended Petition at 3-4. Lick Creek further notes that the PURPA PPA "requires it to pay substantial liquidated damages to DEC if the Project fails to achieve commercial operation and commence delivering power under the contract." *Id.* at 4. Finally, Lick Creek advises that "[t]he Liquidated Damages provisions of the PPA state that these damages are reasonably calculated to compensate the utility for any damages that would result from the Project failing to deliver energy and capacity as required under the contract." *Id.*

The CPRE Program obligates Duke to procure energy and capacity from renewable energy facilities at a cost not to exceed the utility's current forecast of its avoided cost calculated over the term of the PPA. Bids to participate in the CPRE Program are evaluated by the independent third-party administrator, Accion.

Lick Creek observes that for both Tranche 1 and 2 of CPRE, Accion allowed a project with a noncontractual LEO to submit a CPRE bid. However, Lick Creek asserts that starting with the Tranche 2 RFP, projects with contractual LEOs are distinguished and excluded from participation in the CPRE bidding process. Lick Creek explains, "[t]his restriction on eligibility was not part of the Tranche 1 RFP and was not discussed in Duke's Program Plan for Tranche 2." *Id.* at 6. Lick Creek also states that "[i]n written and verbal comments provided during the stakeholder engagement process, [Lick Creek] requested that the IA reconsider this requirement, arguing that it is unreasonable, anticompetitive, and not in the best interest of ratepayers." *Id.* Lick Creek additionally recounts that it "further clarified to the IA that it would commit in writing to terminate its existing PPA and pay liquidated damages if awarded a CPRE PPA." *Id.* at 6-7. However, reports Lick Creek, Accion "declined to reconsider this requirement, responding that 'The Soliciting Entity [*i.e.*, Duke] has determined that the proposed arrangement requiring default on an existing legal obligation is not in the best interests of its ratepayers, and therefore, respectfully disputes the position taken by the prospective bidder.'" *Id.* at 7 (alteration in original).

Lick Creek states that it then submitted a PPA proposal to the CPRE Tranche 2 on March 9, 2020 (Tranche 2 proposal). Lick Creek notes that because the Project has a signed Interconnection Agreement with Duke, pursuant to which it is already making payments for Interconnection Facilities and Upgrades, the Project qualifies as an "Advanced Stage Project" under the Request for Proposals for Tranche 2 published by Accion on October 15, 2019 (Tranche 2 RFP). Accordingly, Lick Creek states that it elected to make its bid as an Advanced Stage Project and "submitted a bid substantially below avoided cost" and below "analogous pricing under the Project's [PURPA PPA]." *Id.* at 4. Also, Lick Creek advises that because it is an Advanced Stage Project, it has no upgrade costs, and its bid on the Tranche 2 RFP "fully accounts for the cost of all Upgrades assigned to the Project, which will not otherwise be assigned to ratepayers." *Id.* Finally, Lick Creek opines that "its bids will be highly competitive in Tranche 2. The Project bid at a significant decrement to avoided cost, even after accounting for integration costs . . . ." *Id.* However, states Lick Creek, on March 11, 2020, Accion notified it that its Tranche 2 proposal was "ineligible to participate in CPRE" due to its existing offtake agreement, the PURPA PPA, and Accion eliminated Lick Creek's CPRE Tranche 2 bid from consideration. *Id.* at 7.

Lick Creek contends that

> requiring projects with existing PPAs to terminate their contracts with Duke in order to bid into CPRE serves no legitimate policy purpose and would discourage such projects from participating in CPRE, reducing the pool of potential CPRE projects and depriving ratepayers of the possible benefits of contracting for energy and capacity from Petitioner's Project at rates below avoided cost.

Id. at 2. In contrast, Lick Creek asserts that if allowed to bid into Tranche 2 of the CPRE Program, (1) the likelihood that DEC will meet its procurement target will increase, (2) ratepayers will benefit from lower aggregated Tranche 2 procurement costs if its Project is selected, and (3) ratepayers will further benefit from the replacement of an avoided cost-based PPA with a CPRE PPA priced "significantly below avoided cost." *Id.* Lick Creek further argues that "[t]he disqualification of Petitioner's proposal from CPRE Tranche 2 at the behest of [DEC] (the counter-party to Petitioner's PPA) is unreasonable, anticompetitive, and not in the best interest of ratepayers." *Id.* at 7.

Also, Lick Creek argues that if its Project were selected for a Tranche 2 CPRE PPA, it would be more advantageous to ratepayers than its existing PURPA PPA with DEC for a number of reasons, including:

> (1) the Project's CPRE bid is significantly below the avoided cost rates approved in the E-100 Sub 158 docket, inclusive of solar integration costs, and below the avoided cost rates in Petitioner's existing PURPA PPA; (2) CPRE PPAs give Duke limited curtailment rights that are not available under Petitioner's existing PURPA PPA; (3) CPRE PPAs, unlike Petitioner's existing PURPA PPA,

> transfer renewable energy certificates to Duke; [and] (4) CPRE PPAs, unlike Petitioner's existing PURPA PPA, account for solar integration costs . . . .

Id. at 8.

Next, Lick Creek asserts that the

> decision not to allow projects with existing PPAs to bid into Tranche 2 lacks any rational policy justification. It is also inconsistent with the IA's decision to allow projects with existing LEO's to bid into Tranche 2 without compromising those LEOs. A PPA is a form of LEO under PURPA, and it is arbitrary and capricious to treat PPAs and non-contractual LEO's differently for purposes of determining CPRE eligibility.

Id. (footnote omitted). Further, Lick Creek opines "that this decision was intended to force Petitioner to cancel its existing PPA or be excluded from CPRE Tranche 2." *Id.* at 8-9. Lick Creek asserts that DEC may be motivated to discourage Lick Creek from bidding into Tranche 2 so as to bolster "the prospects of success of Duke's own Proposals." *Id.* at 9. In addition, Lick Creek argues that given DEC's eligibility to bid into Tranche 2, it should not be permitted to have a voice in limiting the participation of its competitors. Finally, Lick Creek contends that "[i]t is also inappropriate for DEC to use its influence over CPRE policy decisions to pressure Petitioner to terminate its PPA as a condition of participating in CPRE." *Id.*

Accordingly, Lick Creek requests that the Commission enter an order directing Accion to reinstate its Tranche 2 Proposal and issue a declaratory order "clarifying that Projects with existing offtake agreements may bid into CPRE." *Id.*

DEC Response

In its April 8 response DEC states that while it does not dispute the basic facts set forth in Lick Creek's petition, it opposes Lick Creek's petition. DEC notes that Lick Creek's PURPA PPA "expressly requires" that it sell "one hundred percent (100%) of the Capacity, output of Energy (including stored Energy) produced by the Facility . . . ." DEC Response at 2. DEC adds that prior to executing the PURPA PPA, Lick Creek at no time indicated its intent to submit a proposal to CPRE Tranche 2 or that it believed its obligations pursuant to the PURPA PPA to be contingent on the outcome of the Tranche 2 RFP process.

Next, DEC recounts that Accion made the Tranche 2 RFP available for comment on its website on August 15, 2019, in accordance with Commission Rule R8-71(f) and that the initial draft contained the following language: "[a]lso for the avoidance of doubt, [a Market Participant] may not submit a Proposal for a Facility that has an existing offtake agreement" (RFP Off-Take Restriction). *Id.* (alteration in original). DEC further states that "[t]his unambiguous statement was never amended in any way and was included in the final Tranche 2 RFP posted to the IA's website on October 15, 2019 in accordance with Commission Rule R8-71(f)." *Id.*

DEC argues that the structure of House Bill 589, S.L. 2017-192 (HB 589), which enacted the CPRE requirement, among other solar initiatives, supports the RFP Off-Take Restriction: "Nothing in HB 589 contemplated that QFs should be permitted to enter into a Full Avoided Cost PPA or [Green Source Advantage (GSA)] PPA but then attempt to obtain a CPRE PPA in parallel." *Id.* at 3. DEC explains that "N.C. Gen. Stat. § 62-110.8(a) establishes a CPRE procurement target that is adjusted based on the number of QFs that have executed both Full Avoided Cost PPAs and [interconnection agreements]." *Id.* Further, "N.C. Gen. Stat. § 62-110.8(b)(1) mandates that if a QF has executed both a Full Avoided Cost PPA and an [interconnection agreement], then the total CPRE procurement target is adjusted." *Id.* DEC concludes that "[i]n establishing this structure, the CPRE Statute thus clearly contemplated that executing a Full Avoided Cost PPA or participating in a CPRE RFP are mutually exclusive." *Id.* at 4.

DEC also contends that the RFP Off-Take Restriction is reasonable as a matter of policy, arguing that having a PURPA PPA as a backstop will result in less aggressive and competitive bids and create inequity between those MPs with alternative offtakes and those without. Additionally, DEC opines that "if future avoided costs decline substantially from the current projections," then the shorter term of the PURPA PPA may deliver greater savings to ratepayers than a CPRE PPA. *Id.* at 6. Further, DEC states concern that if Lick Creek's petition is granted, then MPs with GSA PPAs may also attempt to bid into the CPRE Program, introducing uncertainty into the GSA Program. Finally, DEC argues that it "did agree to allow projects with a LEO established pursuant to the Commission-approved [Notice of Commitment (NOC) form] to bid into CPRE without losing such LEO in order to not unnecessarily discourage participation. But contrary to Petitioners' assertion, there is a substantial difference between a LEO established through a NOC and an executed PPA." *Id.* at 7.

Further, DEC asserts that the RFP Off-Take Restriction is necessary for the efficiency of administering the CPRE Program:

> Allowing projects with pre-existing off-take arrangements to bid into CPRE also introduces greater uncertainty into the overall procurement process, as Duke and the IA have no way of being certain that a Market Participant will in fact terminate such existing PPA and pay any applicable liquidated damages if selected as a winner. The CPRE evaluation process is complex and involves evaluation of a large number of projects over a short period of time. Allowing a project with an existing off-take agreement into the process introduces yet another element of uncertainty into an already complex and contingent evaluation process. Finally, if a Market Participant with an existing off-take agreement were selected as a winner and then refused to execute CPRE PPA, other projects could be impacted (even if Duke was able to recover the Step 2 Proposal Security amount).

Id. at 7-8.

In addition, DEC criticizes Lick Creek, stating that it could have raised this issue substantially sooner and avoided introducing uncertainty into the Tranche 2 evaluation process. DEC notes that as of the date of its comments, April 8, 2020, Accion "is currently proceeding with its Tranche 2 evaluation with Petitioners' projects excluded[,] and a modification to the

RFP Off-Take Restriction would likely necessitate revaluation and could result in a delay in Tranche 2 completion." *Id.* at 8.

DEC charges that Lick Creek's allegations that DEC may have improper motivations behind the RFP Off-Take Restriction are misleading for several reasons, including that "the RFP Off-Take Restriction is, based on all available evidence, only impacting Petitioners' projects and, if it is conferring any meaningful benefit on other Market Participants, is doing so for all other Market Participants equally." *Id.* at 9. DEC also notes that Lick Creek's allegations ignore the communication restrictions imposed by the CPRE rule, which mandate that no communications are permitted between DEC employees involved in "assisting the IA in the CPRE evaluation" and the separate DEP/DEC or DER Proposal Teams within Duke. *Id.* at 10. Finally, DEC avers that "decisions concerning the contents of the RFP are made by the members of the Duke Evaluation Team (who have no insight into the plans of the DEP/DEC or DER Proposal Teams) in collaboration with the IA." *Id.*

DEC also dismisses Lick Creek's claims that its elimination from Tranche 2 will likely lead to higher CPRE contract prices or make it more difficult for DEC to achieve its Tranche 2 procurement goals as "pure speculation." *Id.* at 11.

With regard to the liquidated damages referenced by Lick Creek, DEC states that "[s]uch liquidated damage provisions are a standard term in each of Duke's negotiated QF PPAs. For the avoidance of doubt, any liquidated damages received under such PPAs will not benefit Duke but are instead credited to customers through fuel rates." *Id.*

Finally, DEC affirms that "there is no evidence or factual basis to suggest that the RFP Off-Take Restriction was imposed specifically to target Petitioners." *Id.* at 12.

DEC requests that the Commission deny Lick Creek's petition.

Reply Comments of Lick Creek

In its April 17 reply Lick Creek contends that DEC's arguments that eliminating the RFP Off-Take Restriction is inconsistent with the CPRE statute (1) will result in less competitive bids, (2) will make administration of the CPRE Program less efficient, and (3) "have no basis in HB 589, in the Commission's CPRE Rules, or in sound public policy." Lick Creek Reply at 1. Lick Creek further asserts that DEC's position is "inconsistent with rational decision-making by potential CPRE [MPs]." *Id.* Finally, Lick Creek reasons that the relief it seeks is "in the interest of ratepayers and would not disrupt the administration of CPRE Tranche 2." *Id.* at 2.

Lick Creek asserts that the following facts are undisputed: (1) that the RFP Off-Take Restriction is DEC's policy, not Accion's, (2) that the RFP Off-Take Restriction necessitates that to bid into the CPRE Program, a QF with an existing PPA must first terminate that PPA in order to be eligible for CPRE, and (3) that Lick Creek's CPRE proposal offers energy and capacity at prices below the avoided cost rates in its existing PURPA PPA.

Lick Creek disagrees that DEC's RFP Off-Take Restriction is consistent with HB 589, noting that "such a restriction is nowhere to be found in the text of the statute," and contends that "[i]f such a restriction did exist, it would also bar a project with an executed PURPA PPA from terminating that PPA and subsequently bidding into CPRE — which Duke says is perfectly fine." *Id.* Lick Creek argues that pursuant to HB 589 it is permissible to shift from "one form of offtake authorized under HB 589 to another." *Id.* at 3.

Lick Creek dismisses DEC's concern that the total volume of CPRE procurement is dependent on the volume of PURPA PPAs and would have to be adjusted if Petitioner were to terminate its existing PURPA PPA in favor of a CPRE PPA. Lick Creek reasons that as the program is "only in Tranche 2 now, . . . any adjustment to the total volume of CPRE procurement will not happen until Tranche 3 or later." *Id.* Further, Lick Creek argues that "[e]ven in the final tranche of CPRE, the [IA] could simply adjust the awarded amount to account for the number of selected projects with existing PURPA PPAs (or a different rule could be established for the final tranche)." *Id.*

Also, Lick Creek expresses skepticism at DEC's stated concern that if Petitioner prevails in its request, the GSA program could be impacted if participants were able to terminate their GSA PPAs in favor of CPRE PPAs. Lick Creek notes that it is not requesting that GSA participants be permitted to bid into CPRE and argues that "it would be entirely reasonable for the Commission to allow projects with PURPA PPAs to bid into CPRE while not allowing projects with GSA Contracts to do so." *Id.* at 4. Finally, Lick Creek states its belief that GSA suppliers would be unlikely to breach their GSA PPAs for monetary and reputational reasons.

Next, Lick Creek contends that the CPRE Program is not intended to pressure MPs into bidding as low as possible:

> HB 589 requires that PPA pricing under CPRE be set competitively, and that the resources procured be "cost-effective." The "cost-effectiveness" of a CPRE Proposal, according to the General Assembly and this Commission, is judged by whether the proposal pricing (inclusive of the cost of upgrades) is at or below avoided cost — not whether the pricing is as low as possible.

Lick Creek Reply at 4 (citations omitted).

Lick Creek also responds to DEC's allegation that allowing projects with preexisting PPAs to bid into CPRE will introduce "greater uncertainty into the overall procurement process;" based upon the possibility that an MP may elect to honor its existing PURPA PPA even if it is offered a CPRE PPA. *Id.* at 5. Lick Creek criticizes DEC's argument stating:

> [T]his assumes irrational behavior on the part of MPs. A QF with an executed PURPA PPA would only make the substantial commitment to participate in CPRE (including the posting of sizable Proposal Security if it selected for the competitive tier) if it decided that a CPRE PPA, at the bid price, would be more favorable than

> its existing PPA. Such an MP has no more reason not to sign a CPRE PPA than any other MP.

Id. (footnote omitted). For these reasons, Lick Creek states that if granted by the Commission, its request will not create uncertainty or otherwise complicate administration of the CPRE Program.

In addition, Lick Creek disputes DEC's claim that the five-year PURPA PPA could be more beneficial to ratepayers than a CPRE PPA. Lick Creek contends that "[i]t is also entirely speculative to assume that avoided costs six years from now will be even lower than the Petitioners' bid prices, which are already below avoided cost, even after accounting for solar integration costs." *Id.* at 6. Lick Creek also notes that "under CPRE, the utility and the ratepayer would have the benefits of limited dispatchability and REC acquisition for the *entire* 20-year term of the PPA." *Id.*

Lick Creek further argues that DEC "misstates the facts concerning the timeliness of Petitioners' request." *Id.* It disputes DEC's claim that the draft Tranche 2 RFP posted on Accion's website on August 15, 2019, contained the express RFP Off-Take Restriction. Lick Creek contends:

> [T]]he Draft RFP made available for comment on August 15, 2019 . . . did *not* include any statement about the RFP Off-Take Restriction. The restriction first appeared in the final RFP published on October 15, 2019 (the date on which Tranche 2 opened for bids), tacked on to the end of a footnote discussing CPCN requirements. . . . To the best of Petitioners' knowledge, the restriction was not discussed in stakeholder meetings or other guidance provided prior to the opening of Tranche 2, and was not added in response to any comments by stakeholders . . . . And the comment period for the Draft RFP closed on September 5, 2019. So potential MPs had no opportunity [to] comment on the restriction prior to it being included in the Final RFP. The addition of the RFP Off-Take Restriction to the RFP at the eleventh hour therefore violated Commission Rule R8-71(f), which requires publication of a draft RFP setting forth the "guidelines and documents, including RFP procedures, [and] evaluation factors" that will guide the process.

Id. at 6-7 (final alteration in original). Lick Creek also notes that it "made repeated attempts to resolve this issue with the IA after it was revealed for the first time in the Final RFP in October 2019," including raising the issue of the RFP Off-Take Restriction via a comment on Accion's website on January 23, 2020, at a stakeholder meeting on February 6, 2020, through comment on Accion's website on February 26, 2020, and again on March 5, 2020. *Id.* at 8.

Lastly, Lick Creek argues that if the Commission decides in its favor, there will be no prejudice or delay because the Project qualifies as Advanced Stage and, therefore, may forego the Step 2 interconnection study. Further, Lick Creek states that as an Advanced Stage project, it can be ranked and evaluated solely on the basis of its bid pricing, then, once evaluated by Accion, "simply be 'slotted in' to the final ranked list of proposals to be delivered by the IA to the Evaluation Team at the conclusion of the Step 2 process, in keeping with Rule R8-77(f)(iv)." *Id.*

at 9. Lick Creek concludes, "[s]o long as a decision is rendered in time for Petitioners' proposals to be ranked before that list is prepared at the end of Step 2, granting the requested relief should not cause any delay or disruption." *Id.*

DISCUSSION AND CONCLUSIONS

The CPRE statute, N.C.G.S. § 62-110.8(a), does not directly answer the question at issue in this proceeding: should an MP have to cancel its existing avoided cost contract to participate in the CPRE Program and submit a proposal in response to a utility's RFP. The Commission, therefore, must interpret the statute in the context of the entirety of HB 589 to answer this question. After careful consideration the Commission concludes that Duke[1] was reasonable in excluding bidders with existing PPAs from CPRE Tranche 2 and finds good cause to deny the relief requested by Lick Creek and to dismiss the petition.

Pursuant to N.C.G.S. § 62-110.8(a), the legislative purpose of the CPRE Program is that 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." Under the bill, Duke is required to "issue requests for proposals to procure and shall procure, energy and capacity from renewable energy facilities" in the aggregate amount of 2,660 MW over a term of 45 months after Commission approval. However, the procurement target established in the legislation for this program adjusts automatically based on a number of conditions, including the amount of renewable energy procured under other programs.

The CPRE Program is only one of the programs established or modified in HB 589. For example, in Part I of the bill, the legislature amended N.C.G.S. § 62-156 and the terms and conditions of future standard and negotiated avoided cost contracts, while grandfathering certain facilities eligible for the standard offer rate schedules and power purchase agreement terms and conditions approved by the Commission in prior avoided cost proceedings. Also, in Part III of the bill the General Assembly authorized a revised Green Source Advantage program to allow Duke to procure renewable energy resources on behalf of North Carolina's major military installations, the University of North Carolina system, and large nonresidential customers. The amount of renewable energy capacity contracted for under these other provisions impacts the amount of capacity required to be procured under the CPRE Program. N.C.G.S. § 62-110.8(b)(1).

The Commission is persuaded that to allow generators already under contract for the sale of their output to Duke to submit proposals to the CPRE Program would thwart the explicit legislative purpose of the CPRE Program. The Commission further agrees with Duke that excluding bidders with existing PPAs is reasonable for administrative efficiency of the CPRE Program. The CPRE evaluation process is complex and involves the evaluation of a large number of projects over a short period of time. Allowing projects with preexisting off-take arrangements that may not execute a CPRE PPA even if selected as a winning competitive bid to participate in the CPRE Program introduces greater uncertainty into the overall procurement process. To reiterate, the purpose of the CPRE Program is to add new renewable energy generation, and the

[1] As envisioned by the statute, N.C.G.S. § 62-110.8(b), Duke filed a petition on behalf of DEC and DEP for approval of a joint CPRE Program, and the decisions herein apply equally to bidders submitting proposals in response to a CPRE RFP for facilities in either the DEC or DEP service territories.

selection of capacity already under contract and the additional effort required to evaluate such proposals does nothing to further this purpose. Therefore, for the foregoing reasons the Commission is persuaded that Duke acted reasonably in excluding bidders with existing PPAs from participating so as to effectuate the purpose of and efficiently administer the CPRE Program.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of October, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

DOCKET NO. SP-8420 SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of ATOOD Solar IV, LLC, for a Certificate of Public Convenience and Necessity to Construct a 4.99-MW Solar Facility in Brunswick County, North Carolina	)))))	ORDER ISSUING AMENDED CERTIFICATE

BY THE COMMISSION: On October 31, 2016, the Commission issued an order granting ATOOD Solar IV, LLC (Applicant), a certificate of public convenience and necessity for the construction of a 4.99-MW_{AC} solar photovoltaic (PV) electric generating facility to be located at 2201 Mercantile Drive NE, Leland, Brunswick County, North Carolina. In addition, the Commission accepted registration of the facility as a new renewable energy facility.

On August 15, 2019, the Applicant notified the Commission of a change of ownership and control.

On July 9, 2020, the Applicant filed an updated site plan with the Commission and requested that the Commission issue an order amending the certificate to recognize the updated site plan.

On July 17, 2020, the Public Staff filed a letter recommending that the Commission grant the requested amended certificate for the facility without requiring republication of notice or further State Clearinghouse review.

On August 19, 2020, the Commission issued an Order requiring the Applicant to publish notice, file an affidavit of publication, and file an updated certificate of service. The Order also required further State Clearinghouse review.

On August 27, 2020, the Applicant filed a verified certificate of service stating that the application and the related public notice were provided to Duke Energy Progress, LLC on August 26, 2020.

On September 22, 2020 and October 6, 2020, the State Clearinghouse filed additional comments. Because of the nature of the comments, the cover letters indicated that no further State Clearinghouse review action by the Commission was required for compliance with the North Carolina Environmental Policy Act.

On September 30, 2020, the Applicant filed an affidavit of publication from the Star-News (Wilmington, North Carolina) stating that the publication of notice was completed on September 20, 2020. No complaints have been received.

IT IS, THEREFORE, ORDERED as follows:

1. That the application of ATOOD Solar IV, LLC, for an amended certificate of public convenience and necessity shall be, and is hereby, approved; and

2. That Appendix A shall constitute the amended certificate of public convenience and necessity issued to ATOOD Solar IV, LLC, for the 4.99-MW_{AC} solar photovoltaic electric generating facility located at 2201 Mercantile Drive NE, Leland, Brunswick County, North Carolina.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of October, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. SP-8420, SUB 0

ATOOD Solar IV, LLC
c/o ARE NC ATOOD, LLC
3414 Peachtree Road, Suite 825, Atlanta, Georgia 30326

is hereby issued this

AMENDED CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
PURSUANT TO N.C. Gen. Stat. § 62-110.1

for a 4.99-MW_{AC} solar photovoltaic electric generating facility

located

at 2201 Mercantile Drive NE, Leland, Brunswick County, North Carolina,

subject to all 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 19th day of October, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

SMALL POWER PRODUCERS – FILINGS DUE PER ORDER

DOCKET NO. SP-4131, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Legacy Biogas, LLC, for Registration of a New Renewable Energy Facility	)) ORDER ACCEPTING REGISTRATION OF) NEW RENEWABLE ENERGY FACILITY)

BY THE CHAIR: On August 21, 2018, as amended February 24, 2020 and March 2, 2020, Legacy Biogas, LLC (Applicant), filed an application to register a new renewable energy facility pursuant to Commission Rule R8-66 for a new renewable energy facility located in Fremont, Wayne County, North Carolina. Applicant stated that its 4.2-MW_{AC} biogas-fueled facility will generate electricity using biogas produced from the process of swine manure, mortality, slaughterhouse and packing house waste. The electricity produced by Legacy Biogas will be only from swine substrate. The biogas collection and pressurizing system was installed with the ability to collect and transfer biogas for the 4 engines, and each engine burn the biogas to produce up 1000 kW_{AC} per engine to combustible gases through waste digester gas (biogas). The digester gas supplies methane to a cogeneration genset. Applicant stated that his facility would become operational on or around September 2018.

The filing included certified attestations that: (1) the facility will be in substantial compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources; (2) the facility will be operated as a new renewable energy facility; (3) Applicant will not remarket or otherwise resell any renewable energy certificates (RECs) sold to an electric power supplier to comply with G.S. 62-133.8; and (4) Applicant will consent to the auditing of its books and records by the Public Staff insofar as those records relate to transactions with North Carolina electric power suppliers.

On March 3, 2020, the Public Staff filed the recommendation required by Commission Rule R8-66(e) stating that Applicant's registration statement as a new renewable energy facility should be considered to be complete. No other party made a filing with respect to these issues.

Based upon the foregoing and the entire record in this proceeding, including the source of fuel stated in the registration statement, the Chair finds good cause to accept registration of Applicant's biogas-fueled facility as a new renewable energy facility. Consistent with the Commission's January 20, 2010 Order Accepting Registration issued in Docket No. SP-578, Sub 0, Applicant may earn RECs only for the electricity produced from the biogas and not for the thermal energy that is used as an input back into the pyrolysis process. In addition, if any organic material other than swine waste is used in the pyrolysis, only that portion of the electricity generated from the biogas that is derived from swine waste is eligible to earn RECs that may be used to meet the respective swine waste set-aside requirements of the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Applicant shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year. Applicant will be required to participate in the NC-RETS REC tracking system (www.ncrets.org) in order to facilitate the issuance of RECs.

IT IS, THEREFORE, ORDERED as follows:

1. That the registration by Legacy Biogas, LLC, for its biogas-fueled facility to be located in Fremont, Wayne County, North Carolina as a new renewable energy facility shall be, and is hereby, accepted;

2. That Applicant shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year; and

3. That the Chief Clerk shall send a copy of this order to the NC-RETS Administrator.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of April, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

DOCKET NO. SP-4667, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Railroad Solar Farm, LLC,	)	AMENDED ORDER REQUIRING
for a Certificate of Public Convenience and	)	PUBLICATION OF NOTICE
Necessity for a 4-MW Solar Facility in	)	AND FURTHER STATE
Robeson County, North Carolina	)	CLEARINGHOUSE REVIEW

BY THE COMMISSION: On November 4, 2014, the Commission issued an Order in the above-captioned docket granting Railroad Solar Farm, LLC (Applicant), a certificate of public convenience and necessity (CPCN) pursuant to N.C.G.S. § 62-110.1(a) for construction of a 4-MW solar generating facility to be located at 409 East Railroad Street in Pembroke, Robeson County, North Carolina. In addition, the Commission accepted registration of the facility as a new renewable energy facility. Applicant stated that it plans to sell the electricity to Duke Energy Progress, LLC.

On July 9, 2020, Applicant filed an amendment to its application. In summary, Applicant stated that the facility was constructed and began operations in 2017, but during a recent routine review of the project it was discovered that there are minor inconsistencies between the site's final constructed footprint and what is on file with the Commission. Applicant enclosed an updated layout showing the facility's final constructed footprint and marked as Railroad Solar Farm, LLC – Final Constructed Layout Exhibit. Applicant stated that the material information within the CPCN and registration remains the same, and that it was providing the final layout based on an abundance of caution. Applicant opined that no further public notice or State Clearinghouse review on the constructed and operational facility is required, and cited the Commission's decision in

Application of Rock Farm, LLC, for a Certificate of Public Convenience and Necessity to Construct a 4.975-MW Solar Photovoltaic Electric Generating Facility in Richmond County, North Carolina in Docket No. SP-1659, Sub 0 (Rock Farm Order), in support of its position. Finally, Applicant requested that the Commission issue an order amending the CPCN to recognize the final, constructed layout.

On July 17, 2020, the Public Staff filed a letter stating that it reviewed Applicant's updated site layout, that it shifts the project onto a new parcel, and that the amended layout differs from the original site layout provided in compliance with Commission Rule R8-64(b)(2), which requires a map or aerial photo showing the location of the facility and the proposed location of the facility's major equipment. Further, the Public Staff stated that R8-64(d)(3) requires applicants "[b]oth before the time construction is completed and after," to advise both the Commission and the utility involved of any material changes to the information in the application. In addition, the Public Staff cited the Commission's Order Issuing Amended Certificate of Public Convenience and Necessity, Approving Transfer of Certificate and Accepting Registration in Docket Nos. SP-3096, Subs 0 and 1, and SP-11559, Sub 0, (Aug. 21, 2018) (CPCN Amendment Order), and stated that the Commission's usual practice in response to a change in a facility's site plan that involves the addition of new land is to issue an order requiring the applicant to publish notice of the amended application, and also send the amended application to the State Clearinghouse for further review, based on the rationale "that the addition of new land likely affects new adjoining landowners, and that those new adjoining landowners should have notice and the opportunity to file a complaint regarding the potential effects of the proposed facility on the enjoyment of their property." CPCN Amendment Order, at 6. The Public Staff stated that the Commission further noted, however, that it "must review each amendment and exercise its discretion to order such measures as it finds appropriate under the circumstances." *Id.* at 7.

Moreover, the Public Staff stated that Applicant's amendment herein was not filed with the Commission until after construction was completed on the site and the facility commenced operations, providing no meaningful opportunity for review of the proposed amended site layout, as would normally be preferred. The Public Staff noted Applicant's reliance on the Commission's 2013 Rock Farm Order, but stated that the Rock Farm Order should be given limited weight based on the different factual circumstances involved in that docket, and, rather, should be viewed as an exception to the Commission's standard practice over the past seven years. Nonetheless, the Public Staff stated that it would not appear that any additional public interest would be served by requiring Applicant to republish notice or to send the application back to the State Clearinghouse for further review. With regard to the Rule R8-64(d)(3) requirement to provide notice of material changes to the site layout after construction is completed, the Public Staff stated that the purpose of this provision is: (1) to address subsequent modifications to facilities; and (2) to ensure that the information filed in the docket system and the information on file with the utility reflects the actual system as constructed. In the present case, the filing helps fulfill this latter requirement. As a result, the Public Staff recommended that the Commission grant the requested amended CPCN for the facility without requiring republication of notice or further State Clearinghouse review.

DISCUSSION AND CONCLUSION

Commission Rule R8-64(d)(3) states:

> Both before the time construction is completed and after, all certificate holders must advise both the Commission and the utility involved of any plans to sell, transfer, or assign the certificate or the generating facility or of any significant changes in the information set forth in subsections (b)(1) thru (b)(5) of this Rule, and the Commission will order such proceedings as it deems appropriate to deal with such plans or changes. The following changes in information are exemplary of changes that require an amendment to the certificate issued for the facility: a transfer of the certificate or the facility, a change in the facility owner's name, a change in the fuel source, or a change in the generating capacity of the facility. The following changes in information are exemplary of changes that require notice to the Commission, but do not require an amendment to the certificate: a change in facility owner's contact information, or a change in the upstream ownership of the facility owner.

The required information set forth in subsections (b)(1) thru (b)(5) of the Rule includes a color map or aerial photo showing the facility's site boundaries and the proposed location of major equipment. Rule R8-64(b)(2)(i).

As the Commission stated in the CPCN Amendment Order, the Commission's general rule is that the addition of new land to a facility's site triggers the requirement to republish public notice so that reasonable notice is provided to landowners whose property may not have been adjoining or otherwise affected by the land that was included in the original site. Likewise, the addition of new land or the repositioning of major equipment on segments of the property not initially identified for such use requires further review by the State Clearinghouse to determine whether the facility's amended use of the property comports with the guidelines of the North Carolina Environmental Policy Act. The fact that a facility has been constructed and is operating has no bearing on the applicability of these requirements.

Therefore, on the basis of the amended application the Commission concludes that Applicant should be required (1) to publish notice of the application in the manner required by N.C.G.S. § 62-82(a) and file an affidavit of publication with the Commission, and (2) to mail a copy of the application and notice, no later than the first date that such notice is published, to the electric utility to which Applicant plans to sell and distribute the electricity and file a signed and verified certificate of service that the application and notice have been provided to the utility. The Chief Clerk of the Commission will deliver copies of the notice to the Clearinghouse Coordinator of the Office of Policy and Planning of the Department of Administration for distribution by the Coordinator to State agencies having an interest in the application.

If a complaint is received within ten days after the last date of the publication of the notice, the Commission will schedule a public hearing to determine whether an amended certificate should be awarded, will give reasonable notice of the time and place of the hearing to the Applicant and to each complaining party, and will require the Applicant to publish notice of the hearing in the newspaper in which the notice of the application was published. If no complaint is received within the time specified above, the Commission may, upon its own initiative, order and schedule a hearing to determine whether an amended certificate should be awarded. If the Commission orders a hearing upon its own initiative, it will require notice of the hearing to be published by Applicant in the newspaper in which the notice of the application was published. If no complaint is received within the time specified and the Commission does not order a hearing upon its own initiative, the Commission may enter an order awarding the amended certificate.

The Commission cannot take any action until after Applicant has filed both the affidavit of publication and the certificate of service. Pursuant to Commission Rule R8-64(c)(2), the Commission will automatically dismiss the application, without prejudice to refile, if Applicant does not file the affidavit of publication and certificate of service within twelve months of the date of this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That Applicant shall publish the Public Notice, attached as Attachment A hereto, once each week for four successive weeks in the manner required by N.C.G.S. § 62-82(a) and shall file an affidavit of publication with the Commission;

2. That Applicant shall mail a copy of the amended application and notice, no later than the first date that such notice is published, to the electric utility to which the Applicant plans to sell and distribute the electricity and file a signed and verified certificate of service that the application and notice have been provided to the utility;

3. That the Chief Clerk of the Utilities Commission will deliver copies of the notice to the Clearinghouse Coordinator of the Office of Policy and Planning of the Department of Administration for distribution by the Coordinator to State agencies having an interest in the application;

4. That Applicant may continue operation of the facility pursuant to the authority granted by the Commission under the original CPCN, unless and until the Commission orders otherwise; and

5. That the Commission will proceed as it deems appropriate after the filing of the affidavit of publication and the certificate of service.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of August, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

ATTACHMENT A

PUBLIC NOTICE

DOCKET NO. SP-4667, SUB 0
APPLICATION OF RAILROAD SOLAR FARM, LLC
FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

NOTICE IS HEREBY GIVEN that on October 31, 2014, Railroad Solar Farm, LLC (Applicant), filed an application, as amended on July 9, 2020, seeking a certificate of public convenience and necessity pursuant to N.C.G.S. § 62-110.1(a) for the construction of a 4-MW solar generating facility to be located at 409 East Railroad Street in Pembroke, Robeson County, North Carolina. Applicant's site layout illustrating the footprint of the facility may change to some degree based on government land use requirements, interconnection requirements, or similar factors. Applicant stated that it plans to sell the electricity to Duke Energy Progress, LLC.

Details of the application may be obtained from the Office of the Chief Clerk of the North Carolina Utilities Commission, 430 N. Salisbury Street, 5th Floor, Dobbs Building, Raleigh, North Carolina 27603 or 4325 Mail Service Center, Raleigh, North Carolina 27699-4300 or on the Commission's website at www.ncuc.net.

If a complaint is received within ten days after the last date of the publication of this notice, the Commission will schedule a public hearing to determine whether an amended certificate should be awarded, will give reasonable notice of the time and place of the hearing to the Applicant and to each complaining party, and will require the Applicant to publish notice of the hearing in this newspaper. If no complaint is received within the time specified above and if the Commission does not order a hearing upon its own initiative, the Commission may enter an order awarding the amended certificate sought by the Applicant.

Persons desiring to lodge complaints may file statements to that effect with the Commission. Such statements should reference Docket No. SP-4667, Sub 0 and be addressed as follows: Chief Clerk, North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4300.

Statements may also be directed to Christopher J. Ayers, Executive Director, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300 or to The Honorable Josh Stein, Attorney General of North Carolina, c/o Consumer Protection-Utilities, 9001 Mail Service Center, Raleigh, North Carolina 27699-9001. Written statements may be e-mailed to utilityAGO@ncdoj.gov.

NOTE TO PRINTER: Advertising cost shall be paid by the Applicant. It is required that the Affidavit of Publication be filed with the Commission by the Applicant.

DOCKET NO. SP-1103, SUB 0
DOCKET NO. SP-25630, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKER NO. 1103, SUB 0

In the Matter of Application of RES Ag-DM 2-1, LLC, for Registration of a New Renewable EnergyFacility DOCKET NO. SP-25630, SUB 0 In the Matter of Application of Align RNG Magnolia, LLC, forRegistration of a New Renewable Energy Facility	))))))))))	ORDER CANCELING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

BY THE CHAIR: On June 20, 2011, in Docket No. SP-1103, Sub 0, the Commission issued an order accepting registration of a new renewable energy facility for a 750-kWAC biomass-fueled combined heat and power (CHP) facility located in Magnolia, in Duplin County, North Carolina.

On August 19, 2020, as amended September 1, 2020, September 3, 2020, and October 30, 2020, Align RNG Magnolia, LLC (Applicant) filed an application to register a new renewable energy facility pursuant Commission Rule R8-66 for the same biomass-fueled CHP facility. In the application, the Applicant provides updated information that the facility became operational on October 5, 2013 and has 0.5 MWAC capacity.

The Applicant's filing included certified attestations that: (1) the facility will be in substantial compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources; (2) the facility will be operated as a new renewable energy facility; (3) the Applicant will not remarket or otherwise resell any renewable energy certificates (RECs) sold to an electric power supplier to comply with N.C. Gen. Stat. § 62-133.8; and (4) the Applicant will consent to the auditing of its books and records by the Public Staff insofar as those records relate to transactions with North Carolina electric power suppliers.

On September 4, 2020, the Public Staff filed the recommendation required by Commission Rule R8-66(e), stating that the Public Staff has completed its review of the Applicant's registration statement. Based upon its review, the Public Staff recommends that the Applicant's registration statement be considered complete and that the facility be considered a new renewable energy facility. No other party made a filing with respect to these issues.

Based upon the foregoing and the entire record in this proceeding, including the source of fuel stated in the registration statement, the Chairman finds good cause to accept registration of Applicant's biogas-fueled facility as a new renewable energy facility. Consistent with the Commission's January 20, 2010 Order Accepting Registration issued in Docket No. SP-578, Sub 0, Applicant may earn RECs only for the electricity produced from the biogas and not for the thermal energy that is used as an input back into the pyrolysis process. In addition, if any organic material other than swine waste is used in the pyrolysis, only that portion of the electricity generated from the biogas that is derived from swine waste is eligible to earn RECs that may be used to meet the respective swine waste set-aside requirements of the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Applicant shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year. Applicant will be required to participate in the NC-RETS REC tracking system (www.ncrets.org) in order to facilitate the issuance of RECs.

IT IS, THEREFORE, ORDERED as follows:

1. That the registration as a new renewable energy facility of the750-kWAC biomass-fueled combined heat and power facility located in Magnolia, Duplin County, North Carolina and owned by RES Ag-DM 2-1, LLC, accepted in Docket No. SP-1103, Sub 0, shall be, and is hereby, canceled;

2. That Docket No. SP-1103, Sub 0, shall be, and is hereby, closed;

3. That the application for registration as a new renewable energy facility filed by Align RNG Magnolia, LLC for its 0.5 MWAC biomass-fueled combined heat and power facility located in Magnolia in Duplin County, North Carolina, shall be, and is hereby, accepted;

4. That Align RNG Magnolia, LLC shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year; and

5. That the Chief Clerk shall send a copy of this order to the NC-RETS Administrator.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of November, 2020

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. SP-9590, SUB 0
DOCKET NO. E-2, SUB 1159
DOCKET NO. E-7, SUB 1156

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. SP-9590, SUB 0 In the Matter of Application of Stanly Solar, LLC, for a Certificate of Public Convenience and Necessity to Construct a 50-MW Solar Facility in Stanly County, North Carolina DOCKET NO. E-2, SUB 1159 DOCKET NO. E-7, SUB 1156 In the Matter of Joint Petition of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, for Approval of Competitive Procurement of Renewable Energy Program	ORDER DENYING MOTION FOR RETURN OF CPRE PROPOSAL SECURITY

BY THE COMMISSION: On January 14, 2020, Stanly Solar, LLC (Stanly), filed a Motion for Return of CPRE Proposal Security in the above-captioned dockets (Motion) requesting that the Commission compel Duke Energy Progress, LLC (DEP), to return the $1 million surety bond provided by Stanly as Proposal Security for its bid in Tranche 1 of the Competitive Procurement of Renewable Energy (CPRE) Program authorized by House Bill 589 (S.L. 2017-192).

On February 20, 2020, Accion Group, LLC, the Independent Administrator for the CPRE Program (hereinafter IA or Accion), filed a response to Stanly's motion (Accion's First Response) in Docket Nos. E-2, Sub 1159 and E-7, Sub 1156 (CPRE Dockets).

On February 24, 2020, DEP and Duke Energy Carolinas, LLC (DEC; together with DEP, the Companies or Duke), filed a joint response to Stanly's motion (Duke's Response) in the CPRE Dockets.

On March 13, 2020, Stanly filed a reply in support of its motion (Reply).

Finally, on April 21, 2020, Accion filed a response to Stanly's reply (Accion's Second Response) in the CPRE Dockets.

SUMMARY OF THE PLEADINGS

Stanly's Motion

Stanly states that it owns a 50-MW solar project under development in Stanly County, North Carolina, that it submitted as a proposal for a CPRE Tranche 1 Power Purchase Agreement (PPA). Pursuant to a system impact study from December 2017, Stanly notes that it was designated as a late-stage project,[1] meaning that it was not included in the Tranche 1 grouping study and would be required to bear the cost of its own network upgrades. Also, Stanly explains that the Commission-approved Tranche 1 CPRE Program Guidelines require that a Market Participant's (MP) facility must be in service prior to January 1, 2021.

On December 6, 2018, the IA notified Stanly that it was selected to proceed to Step 1 of the CPRE selection process. The Tranche 1 RFP required third-party MPs, including Stanly, to "provide Proposal Security in the amount of $20/kW in order to proceed to Step 2 of the evaluation process." Motion at 3. Around that time, Stanly recalls that

> based on the rough interconnection timelines set out in Stanly's System Impact Study as well as correspondence with Duke's interconnection team, it appeared that the project probably would not be able to achieve interconnection by the January 1, 2021 in-service deadline, depending on how quickly Duke was able to issue the Interconnection Agreement and complete construction under the agreement. In addition to potentially impacting Stanly's eligibility for Tranche 1, a late interconnection could negatively impact the economics of the project due to increased carrying costs, expiration of project agreements, and increased exposure to changes in available financing.

Id. at 4-5. However, Section VI(A) of the CPRE Tranche 1 RFP provides that in the event that during the Step 2 evaluation process the T&D Sub-Team determines that "any required Interconnection Facilities or System Upgrades cannot be completed by January 1, 2021, but can be completed by July 1, 2021," the IA must notify the MP, and the MP has the election to either remain in the RFP or withdraw. *Id.* at 3. In addition, Stanly notes that Accion's responses to Frequently Asked Questions by MPs states;

> Section VI(A) "provides the MP with the opportunity to withdraw a proposal in the event that the projected completion date for Interconnection Facilities and System Upgrades cannot be completed by January 1, 2021, but can be completed by

[1] Pursuant to the Tranche 1 Request for Proposals (RFP), a project that executed a state-jurisdictional Facilities Study Agreement and committed to fund any Network Upgrades identified in its System Impact Study would be designated a "Late Stage Proposal." Proposals designated as "Late Stage" were not to be evaluated as part of the System Impact Grouping Study. Instead, Late Stage Proposals were studied under the default interconnection study process and had to bear the cost of their own Network Upgrades.

> July 1, 2021. *In such a case, if the MP decides to withdraw the Proposal, the Proposal Security would be released.*"

Id.

Stanly asserts that "in reliance on the RFP's assurance that Stanly would be allowed to withdraw from CPRE without penalty if it was ultimately determined that the project could not be interconnected by January 1, 2021, Stanly opted to proceed to Step 2." *Id.* at 5. Stanly states that it posted a $1 million surety bond as Proposal Security on January 4, 2019, which was rejected by Duke due to form. Stanly states that it posted a revised surety bond on February 5, 2019.

Stanly recalls that after posting the Proposal Security in January of 2019, it received additional information tending to indicate that the project would not be in service by the Tranche 1 deadline of January 1, 2021; however, Stanly asserts that it "did not receive any notification from the IA during Step 2 that its interconnection date might be later than January 1, 2021, and it was not provided the option to withdraw in Step 2 of the selection process." *Id.*

Stanly states that the IA notified it on April 10, 2019, that its bid had been selected to participate in the CPRE Program and that it would forfeit its Proposal Security if it did not execute a PPA.

Stanly states that it informed the IA on May 6, 2019, that "because of significant changes in project economics due to an increase in solar panel prices after Stanly posted its Proposal Security in January 2019, its construction costs had increased and Stanly likely would not be able to post PPA security at the completion of Stage 2." *Id.* at 5 n.3. At that time, Stanly requested permission to withdraw from Tranche 1 without forfeiting its Proposal Security, but the IA denied the request. Stanly asserts that other MPs were not required to post Proposal Security until March or April 2019, at which time the panel price increase had already occurred. Further, Stanly speculates that "[a] significant proportion of those projects opted not to post Proposal Security and proceed to Step 2, and it appears that the price increase was a significant factor in those MPs' decisions to withdraw." *Id.* Stanly argues:

> This created an unintended but nonetheless unfair advantage for the later selected MPs, as they had more current market knowledge at the time they were asked to post their Proposal Security. If Stanly had been given the same opportunity to post in March/April, with knowledge of the increase in module prices, it would have elected not to do so.

Id.

Stanly asserts that it informed the IA on June 26, 2019, that "based on the most recent information received from Duke," the project would be unable to make the in-service deadline of January 1, 2021. *Id.* at 5. Accordingly, pursuant to Section VI(A) of the RFP, Stanly states that it again requested to withdraw its proposal and have its Proposal Security returned, but that on

July 5, 2019, the IA again denied Stanly's request. Stanly further alleges that the IA justified its denial as follows:

> (1) The IA has not informed the MP that interconnection cannot be completed by January 1, 2021; (2) Duke Transmission has yet to establish a date for completion of associated system upgrades, and, ergo, there has not been a determination that the system upgrades will not be completed until at least July 2021; and (3) Should Duke Transmission fail to complete its responsibilities necessary for the MP to interconnect by the established COD, that would be a contract dispute pursuant to the terms of the PPA and not something to be adjudicated before the fact.

Id. at 6 (internal quotations removed).

Stanly explains that it contacted the IA on July 8, 2019, to clarify that Duke's Transmission Group had consistently told Stanly that "the project's interconnection facilities and upgrades would not be completed until at least April 2021," and to deny that a delay in interconnection until after the in-service deadline would give rise to a contract dispute. *Id.* at 6-7.

Stanly states that it received a final Interconnection Agreement from Duke on July 11, 2019, confirming that "the projected in-service for the project would not occur until May 31, 2021." *Id.* at 7.

When the IA did not respond to Stanly's July 8, 2019 communication, on July 16, 2019, Stanly contacted Duke and asserted that it had "improperly been denied the opportunity to withdraw during Step 2 based on its projected in-service date being after January 1, 2021," and requested return of its Proposal Security. *Id.* Stanly asserts that Duke has failed to provide a substantive response to its July 16, 2019 request, and that on November 25, 2019, without notice, Stanly's surety received a demand from Duke for payment on the surety bond within ten days. Stanly further alleges that "[t]o this day, Duke has not provided any rationale for refusing Stanly's request to return the Proposal Security, and the IA has not explained why the information Stanly provided in its July 8, 2019 correspondence does not justify return of Stanly's Proposal Security." *Id.*

In support of its Motion, Stanly argues:

> By the time the Step 2 analysis was performed, Duke's T&D Team knew the extent of Stanly's required upgrades [and] knew that Stanly could not be interconnected by January 1, 2021. Whether the IA was not informed of this fact or simply ignored it, the IA did not give Stanly the option to withdraw during Step 2 as required by the RFP. Thus the procedures set forth in the Tranche 1 RFP were not followed, and as a result Stanly was denied the opportunity to withdraw during Step 2. Given the changes in project economics after Stanly was required to post Proposal Security, Stanly would have taken the opportunity to withdraw if it had been available.

Id. at 8-9. Stanly contends that "[t]o remedy the IA's failure to follow the procedures set forth in the Tranche 1 RFP — procedures upon which Stanly and other MPs relied — the Commission should require the release of Stanly's Proposal Security." *Id.* at 10.

Stanly next alleges that it is inequitably disadvantaged by having to pay the Proposal Security compared to a Duke-sponsored asset acquisition project in Onslow County that was selected for a PPA but later cancelled for economic reasons and which was not required to post Proposal Security. Stanly notes that the IA's final Tranche 1 report "noted this disparity" by stating "in effect, the DEP/DEC Team and the developer [of the asset acquisition proposal] had a free option to withdraw at any time, which the IA believes was an unanticipated result." *Id.* (citing to Final Report at 6). Stanly further contends that for it to forfeit $1 million for withdrawing from Tranche 1 compared to a Duke-sponsored proposal being allowed to withdraw without financial penalty violates Commission Rule R8-71(d)(5)(ix) "that all proposals were treated equitably through the CPRE RFP Solicitation."

Finally, Stanly contends that if the Commission orders Duke to refund its Proposal Security, such an action would not cause harm to any party. Stanly further states that "[i]f Duke were to retain Stanly's Performance Security it would simply be a one million dollar windfall for the company." *Id.* at 11. As such, Stanly requests that the Commission direct Duke to release and return its Tranche 1 Proposal Security.

Accion's First Response

As a preliminary matter Accion "notes that the terms of the Surety Bond expressly identified that all disputes were to be 'resolved in the State and Federal courts in North Carolina'" and that Stanly agreed to the forum selection clause of the bond. Accion's First Response at 2.

Accion opposes Stanly's motion on two primary bases. First, Accion contends that Stanly's reason for not executing the CPRE PPA offer was economic (due to the increased price of solar PV modules) and not related to a projected in-service date past the January 1, 2021 deadline.

Second, Accion argues that Stanly misstates Section VI(A) of the CPRE Tranche 1 RFP. As background, Accion notes:

> RFP Section VI(A) was intended to provide the opportunity to permit a Proposal to move forward if the Duke T&D Evaluation Team determined and informed the IA that necessary system upgrades for a Project could be completed within a few months of January 1, 2021, rather than having a 'bright line' that would eliminate a viable Proposal based on a strict enforcement of the January 1, 2021 COD.

Id. at 5. Accion denies that pursuant to Section VI(A), the Duke T&D Team and the IA were required to determine whether necessary system upgrades might not be completed by the January 1, 2021 in-service deadline but could be made by July 1, 2021. Rather, Accion contends:

> During the Step 2 evaluations the T&D Sub-Team did not determine a specific in-service date for Stanly and therefore had no basis to inform the IA regarding a specific interconnection timeline. In fact, the IA first learned of this claim when Stanly posted a message in the IA Website on June 26, 2019, a full 78 days after completion of the Step 2 evaluations and after Stanly was informed on

> April 9, 2019[,] that their Proposal was selected as a winner. Accordingly, Stanly's assertion that the IA failed to comply with the terms of the RFP is erroneous.

Id. Accion further denies that Step 2 of the CPRE process includes an estimate of "a firm in-service date." *Id.* at 6. Rather, Accion contends that the CPRE Tranche 1 required each MP to prove the ability to complete their Project by the January 1, 2021 in service date. Per Accion, "a specific in-service date is only established at the time the Interconnection Agreement is executed." *Id.* at 6.

In conclusion, Accion requests that the Commission "require MPs to stand by Proposals, as set forth in the approved RFP," and asserts that "[t]he Proposal Security is a way to make sure that the MP will stand by their Proposal, if selected as a winner, and not withdraw for business reasons at the eleventh hour." *Id.* at 11.

Duke's Response

Like Accion, as a preliminary matter Duke questions whether the Commission is the appropriate forum for settling the dispute over the return of Stanly's Proposal Security. Duke cites to Paragraph 12 of the surety bond, which states:

> All disputes relating to the execution, interpretation, construction, performance, or enforcement of the Bond and the rights and obligations thereto will be governed by the laws of, and resolved in the State and Federal courts in North Carolina. The rights and remedies of Duke Energy herein are cumulative and in addition to any and all rights and remedies that may be provided by law or equity.

Duke Response at 2.

Duke opposes Stanly's motion, primarily asserting that Tranche 1 was conducted in compliance with the RFP terms, including Section VI(A). Duke clarifies that "the Step 2 evaluation process is not intended nor can it identify a specific interconnection date." *Id.* at 3. Rather, Duke states that "a winning CPRE project cannot be provided a firm in-service date until completion of the interconnection process because that is the point in time at which the fully-scoped work is identified and the number of non-CPRE transmission-connected projects with executed Interconnection Agreements is definitively known." *Id.* at 3-4. Specifically, regarding Stanly, Duke first notes that because Stanly was not dependent on any major transmission upgrades, it was "not notified pursuant to Section VI(A) of the RFP." *Id.* at 4. Second, Duke states that because Stanly was a Late Stage Proposal, it was not included in the Step 2 grouping study, not specifically evaluated by the T&D Sub-Team, and "therefore the provision of Section VI(A) are inapplicable" to Stanly. *Id.*

Duke also addresses Stanly's allegation regarding the Duke-sponsored Asset Acquisition project in Onslow County, distinguishing the Asset Acquisition component of CPRE, which allows third parties to bid in assets for acquisition by Duke, from the PPA bid process in which Stanly submitted a proposal, and noting that "Stanly is not alleging that any violation of the RFP occurred with respect to the DEC/DEP Proposal Team withdrawal." *Id.* at 6.

Next, Duke states that it has worked with the IA and stakeholders, consistent with the Commission's direction, to implement lessons learned into Tranche 2. Duke notes that such improvements include revising the RFP to clarify that no firm in-service date will be provided during the Step 2 evaluation and modifying the Asset Acquisition process to require third-party Asset Acquisition bidders to post security when the bid is made.

Finally, Duke rebuts Stanly's allegations regarding the purpose and function of the security bond. Duke clarifies that "the intent of the Step 2 surety bond is not to cover study costs. Instead, the surety bond is intended to protect integrity of the RFP process by ensuring that projects that are moved into the Step 2 evaluation actually move forward to PPA if selected as a winning project." *Id.* at 7. Also, Duke disagrees with Stanly's assertion that if Duke draws on the bond it will be a windfall for Duke. Rather, Duke notes that "the amounts would be credited to customers, including to North Carolina retail customers through the CPRE tariff." *Id.*

Duke concludes that "in light of the totality of the circumstances, it was appropriate to draw on the Stanly surety bond." *Id.* at 8.

Stanly's Reply

In its reply Stanly first denies that its motion relates to "'the execution, interpretation, construction, performance, or enforcement' of the Surety Bond" and contends that its Motion is therefore not subject to the forum selection clause of the bond. Reply at 3. Instead, Stanly contends that its Motion arises from the failure of Accion to follow the RFP rules. Stanly argues that the dispute is within the Commission's purview, citing to N.C.G.S. §§ 62-110.8 and -73, which authorize the Commission to "administer all aspects of the CPRE Program, to supervise the Independent Administrator, and to hear complaints arising out of the acts or omissions of public utilities." *Id.* at 3.

Next, Stanly disagrees with Duke's assertion that the Step 2 date was not intended to determine a firm in-service date. Stanly also contends that even if it is "difficult to determine a precise in-service date for a project with no Interconnection Agreement, knowing a project's exact in-service date generally is not necessary to determine whether it will be able to go in-service by a particular deadline." *Id.* at 6-7.

Stanly again asserts that Accion failed to follow Section VI(A) of the RFP and opposes Duke's position that Section VI(A) of the RFP was inapplicable to Stanly because as a Late Stage Proposal it was not included in the Step 2 Grouping Study. Stanly notes that "neither Section VI(A) of the Tranche 1 RFP nor Section VI(C), which describes the treatment of Late Stage Proposals, says that Late Stage Proposals are treated any differently for purposes of determining in-service dates." *Id.* at 9. Stanly further alleges that that during Step 2 Duke had "ample information" to determine that Stanly's project would not make the in-service deadline of January 1, 2021. *Id.* at 7. Building on this assumption, Stanly contends that because Duke knew during Step 2 that Stanly's project could not make the January 1, 2021 in-service date and Stanly conveyed this information to Accion, Section VI(A) was violated and "Stanly was deprived of its right to withdraw from Tranche 1, as set forth in the RFP." *Id.* at 8.

Accion's Second Response

In filing its second response Accion seeks leave to "submit additional observations and to seek guidance of the [Commission] on issues that could have significant impact on CPRE Tranche 2 and Tranche 3." Accion's Second Response at 1. Particularly, Accion seeks the Commission's review of the following issues: (1) Whether an established proforma Surety Bond is subject to review after the conclusion of a CPRE Tranche, and (2) at what point a CPRE Tranche is final and no longer subject to challenge.

With regard to the first issue, Accion objects to what it characterizes as Stanly's request to revise the terms of the Surety Bond, which it states "were fully vetted with stakeholders and subject to the comment process required by the Commission." *Id.* at 2 [pages unnumbered]. Accion contends that "[t]his approach would neuter the ability to hold MPs responsible for their bids and open the door for MPs to withdraw at any point up until the execution of a PPA." *Id.*

On the second issue, Accion states that "the Commission's guidance on when each CPRE Tranche is final and no longer subject to challenge will assist the IA in the administration of the Program." *Id.* Accion further states that the "establishment of a firm deadline" is needed "to bring certainty to the decision-making by the IA and Duke." *Id.* at 3. Accion notes that "in some jurisdictions the finality of PPAs is established as of when the period for challenges and appeals has tolled." *Id.*

DISCUSSION AND CONCLUSIONS

As a preliminary matter, the Commission is tasked with implementation of the CPRE program pursuant to N.C.G.S. § 62-110.8. Stanly's Motion concerns implementation of the CPRE Program — particularly whether Accion reasonably implemented Section VI(A) of the Tranche 1 RFP — not enforcement of the Proposal Security, and, therefore, is properly before the Commission.

The Commission has carefully considered all of the pleadings filed in this matter and is persuaded that the provisions of Sections II(F) and VI(A) of the Tranche 1 RFP providing for the return of Proposal Security upon withdrawal are inapplicable to Stanly because Stanly, as a Late Stage Proposal, was not specifically evaluated by the T&D Sub-Team during Step 2.

As Stanly states in its Motion, Section II(F) of the Tranche 1 RFP requires that Proposal Security be posted by third-party MPs upon notification by the IA that its proposal has been selected to move into Step 2 of the evaluation process. Section II(F) of the RFP further provides that this Proposal Security will be released "if the MP elects to withdraw the Proposal *pursuant to Section VI(A),*" (emphasis added), and Section VI(A) allows an MP to withdraw from the RFP under specific limited circumstances:

> *In the event that the T&D Sub-Team determines during the Step 2 evaluation process* that any required Interconnection Facilities or System Upgrades cannot be completed by January 1, 2021, but can be completed by July 1, 2021, the IA will notify the MP of the projected completion date of the Interconnection Facilities and

> System Upgrades and the MP will have the option to elect to either allow the Proposal to remain in the RFP or withdraw the Proposal from the RFP. If the T&D Sub-Team determines that any required Interconnection Facilities or System Upgrade cannot be completed by July 1, 2021, the IA will remove the Proposal from further consideration.

RFP at VI(A) (emphasis added). Stanly argues that Section VI(A) applies because *it* notified the IA that based on the latest information received from Duke *by Stanly* that the project would be unable to make the in-service deadline of January 1, 2021, and therefore it was electing to withdraw pursuant to Section VI(A) and have its Proposal Security released pursuant to Section II(F). However, the right to withdraw provided in Section VI(A) is only available to projects that have undergone the Step 2 evaluation by the T&D Sub-Team. As a Late Stage Proposal, Stanly's proposal was not included in the Step 2 grouping study and not evaluated by the T&D Sub-Team but evaluated in the normal course of the interconnection application process. Thus, an essential element of Section VI(A) — that the MP find out during the Step 2 evaluation that necessary upgrades required for its project cannot be completed before the in-service deadline — is not present in this case.

Stanly complains that it did not receive notification from the IA during Step 2 that its interconnection date might be later than January 1, 2021, and that it was not provided the option to withdraw in Step 2 of the selection process. However, Stanly's proposal was evaluated under Section VI(C) of the RFP, which has no similar provision for withdrawal. Further, Stanly admits in its Motion that it knew at the time Accion notified Stanly that it had been selected to proceed to Step 2 that "based on the rough interconnection timelines set out in Stanly's System Impact Study as well as correspondence with Duke's interconnection team, it appeared that the project probably would not be able to achieve interconnection by the January 1, 2021 in-service deadline. . . ." Motion at 4. Thus, the Commission finds that Stanly assumed the risk inherent with opting to proceed to Step 2 and posting the Proposal Security despite having knowledge at the time that its project would likely not make the in-service deadline. The provisions of Section VI(A) of the RFP allowing certain MPs to withdraw "[i]n the event that the T&D Sub-Team determines during the Step 2 evaluation process that any required Interconnection Facilities or System Upgrades cannot be completed by January 1, 2021, but can be completed by July 1, 2021," did not apply to the evaluation of Stanly's proposal as a Late State Proposal under Section VI(C).[1]

Second, Section II(F) of the RFP provides that the Proposal Security will be released "if the Proposal is eliminated by the IA due to failure to meet any required RFP criteria or action." In this case, however, the fact that the project's in-service date was projected to be after the Tranche 1 in-service deadline of January 1, 2021, did not preclude Stanly from being selected as a winning bid. Only projects for which upgrades were not expected to be complete by July 1, 2021, were removed from further consideration. Stanly states that Duke informed it that its upgrades would likely be completed in April 2021, *id.* at 7, and Stanly was notified by the IA that its proposal had been selected as a winning bid. *Id.* at 5. Thus, Stanly's proposal was not eliminated by the IA for failure to meet

[1] While the Commission recognizes that Section VI(A) of the Tranche 1 RFP was amended for Tranche 2 to clarify that no firm in-service date will be provided during the Step 2 evaluation, the Commission does not find this fact to be outcome determinative in this dispute.

any required RFP criteria or action — rather, Stanly requested to withdraw — and this provision of the RFP potentially allowing the release of Stanly's Proposal Security is similarly unavailable.

The facts asserted in Stanly's Motion reveal that it was motivated to withdraw from CPRE Tranche 1 by a change in project economics rather than the project's in-service date, which, as stated above, Stanly knew would likely be after the Tranche 1 in-service deadline prior to posting the Step 2 Proposal Security. Stanly states that it informed Accion that "because of significant changes in project economics due to an increase in solar panel prices after Stanly posted its Proposal Security in January 2019, its construction costs had increased and Stanly likely would not be able to post PPA security at the completion of Stage 2." *Id.* at 5 n.3. Stanly again explicitly states in its Motion that it "was selected as a winning bid in CPRE Tranche 1, but was unable to execute a PPA because of changes in project economics after it posted Proposal Security in January 2019." *Id.* at 2.

Further, the CPRE Program was enacted in part to give utilities more control over purchases from solar facilities than allowed under the federal Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3134 (PURPA). As such, utilities should be allowed to include reasonable guidelines for participation in the CPRE Program. The Commission is persuaded that Duke acted reasonably in requiring the Step 2 Proposal Security with "the intent . . . to protect integrity of the RFP process by ensuring that projects that are moved into the Step 2 evaluation actually move forward to PPA if selected as a winning project." Duke Response at 6.

For the foregoing reasons, the Commission, therefore, concludes that Duke was reasonable in not releasing Stanly's Proposal Security pursuant to the CPRE Tranche 1 RFP and finds good cause to deny the relief requested by Stanly and to dismiss Stanly's Motion. Contrary to Stanly's assertions, the forfeited Proposal Security does not result in a windfall to Duke but is credited to Duke's customers. Lastly, in dismissing Stanly's challenge in this proceeding, the Commission declines at this time to establish the firm deadline for the finality of CPRE tranches requested by Accion.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of October, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

Commissioner Daniel G. Clodfelter dissents.
Commissioner Kimberly W. Duffley dissents. Commissioners Clodfelter and Jeffrey A. Hughes join in Commissioner Duffley's dissent.

DOCKET NO. SP-9590, SUB 0
DOCKET NO. E-2, SUB 1159
DOCKET NO. E-7, SUB 1156

Commissioner Daniel G. Clodfelter, dissenting:

I join in the dissent by Commissioner Duffley. I do not contend that the majority misreads, misunderstands, or misapplies the procedures adopted for and applicable to bidders in Tranche 1. However, as the circumstances of this petition demonstrate, those procedures created a structural inequity, unintentional though it may have been, between utility-sponsored proposals and those of market participants such as Stanly Solar. That inequity played itself out when Stanly Solar was required to forfeit its Proposal Security while a utility-sponsored proposal was allowed to withdraw after being selected as a winning bidder, all without having had to post any type of security along the way. This structural disparity has now been resolved for Tranche 2. Because the rights or obligations of no other party would be affected by the relief sought in the petition, I believe the equitable result would be to require the return of Stanly Solar's Proposal Security.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

DOCKET NO. SP-9590, SUB 0
DOCKET NO. E-2, SUB 1159
DOCKET NO. E-7, SUB 1156

Commissioner Kimberly W. Duffley, dissenting:

I dissent from the majority because the majority ignores the Independent Administrator's inequitable treatment of proposals. Specifically, Stanly Solar was required to forfeit a previously submitted Proposal Security when it withdrew its Third-Party Market Proposal, while an Asset Acquisition Proposal sponsored by the DEC/DEP Proposal Team withdrew without consequence. This inequitable treatment of proposals that results from a strict enforcement of the structure of Tranche 1 dictates my dissent from the majority. Based upon this inequitable treatment and the fact no party, including the majority, suggests that a return of Stanly's Proposal Security would cause actual harm, I would allow Stanly's Motion for Return of CPRE Proposal Security.

North Carolina General Statute § 62-110.8(d) states,

> The third party entity [Accion] shall develop and publish the methodology used to evaluate responses received pursuant to a competitive procurement solicitation and to ensure that all responses are treated equitably.

N.C.G.S. § 62-110.8(d). Further, Commission Rule R8-71(d)(iv), (viii), and (ix) state that the IA's duties shall include:

> (iv) Develop and publish the CPRE Program Methodology that shall ensure equitable review between an electric public utility's Self-developed Proposal(s) as

addressed in subsection (f)(2)(iv) and proposals offered by third-party market participants.

(viii) Evaluate the electric public utility's Self-developed Proposals.

(ix) Provide an independent certification to the Commission in the CPRE Compliance Report that all electric public utility and third party proposals were evaluated under the published CPRE Program methodology and that all proposals were treated equitably through the CPRE RFP Solicitation(s).

No party disagrees that under the initial construct of Tranche 1, a Third Party MP was required to provide Proposal Security after being selected as a competitive bid and an Asset Acquisition Proposal sponsored by the DEC/DEP Proposal Team was not required to provide a similar Proposal Security or any functional equivalent. In fact, in its Updated CPRE Tranche 1 Final Report of the Independent Administrator filed on July 23, 2019 (Final Report), the IA indicates this fact, stating "[t]hat based upon the experience of Tranche 1, the IA recommends revising the Proposal security requirements . . . [finding that a] proposal security or some functional equivalent should be required in the case of both Duke self-developed projects and Asset Acquisition projects that the DEC/DEP team elects to sponsor." Final Report at 5-7. The IA followed through on its recommendation and revised the Tranche 2 RFP which now requires both the Asset Acquisition Proposals and the Utility Self-Developed Facilities to provide such Proposal Security or a functional equivalent. *See* Verified Petition for Declaratory Ruling and Other Relief, Attachment A, pp. 7-8, Docket No. E-7 Sub 1156 (March 30, 2020).

The IA's own statements and its actions to revise Tranche 2 as outlined above support Stanly's claim that the Stanly proposal and the Asset Acquisition Proposal sponsored by the DEC/DEP Team in Tranche 1 were not treated equitably. The cure for this inequitable treatment is to return Stanly's Proposal Security.

Finally, in light of the fact that in its CPRE Tranche 1 Final Report, the IA labels Tranche 1 as a "beta test" of the CPRE Program, the IA and the Commission should allow for flexibility and not require the strict enforcement of terms. Some flexibility in the administration of Tranche 1 is especially true under the circumstances of the present case in which two proposals were not treated equitably and where no party claims actual harm. The only "harm" claimed is by the Companies stating that "the surety bond is intended to protect the integrity of the RFP process by ensuring that projects that are moved into Step 2 evaluation actually move forward to PPA if selected as a winning project." Duke Response at 7. This harm to the process is illusory where the IA calls Tranche 1 a "beta test" and thereafter changes the process for Tranche 2. Although I do not remember any party making this claim, the other possible claim of harm may be the threat of not fulfilling the targeted MWs. However, Tranche 2 and a possible Tranche 3, as well as other potential non-dispatchable PPAs, exist to accomplish the procurement goal. Because I find that the majority requires strict compliance for compliance's sake and that such strict compliance is not in the public interest, I dissent and would instead allow Stanly's motion for a return of the CPRE Proposal Security.

/s/ Kimberly W. Duffley
Commissioner Kimberly W. Duffley

DOCKET NO. T-4772, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Manco Carriers, LLC, d/b/a Manco Property Maintenance, P.O. Box 1082, Lewisville, North Carolina 27023 – Termination of Liability Insurance Coverage	))))	RECOMMENDED ORDER CANCELLING CERTIFICATE OF EXEMPTION

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Friday, February 7, 2020 at 10:00 a.m.

BEFORE: Nicholas C. Jeffries, Hearing Examiner

APPEARANCES:

For the Respondent:

None

JEFFRIES, HEARING EXAMINER: On January 7, 2020, the Commission issued an Order in this docket requiring Manco Carriers, LLC, d/b/a Manco Property Maintenance, (Respondent) to appear before the Commission on February 7, 2020, and show cause, if any it had, why its certificate of exemption should not be cancelled for willful failure to maintain on file with the North Carolina Division of Motor Vehicles evidence of liability insurance coverage as required by N.C. Gen. Stat. § 62-268 and Commission Rule R2-36.

At the call of the matter for hearing, Respondent was neither present nor represented by counsel.

Based upon the entire record in this docket, the Hearing Examiner makes the following

FINDINGS OF FACT

1. The Respondent holds Certificate of Exemption No. C-2936 issued by this Commission.

2. The North Carolina Division of Motor Vehicles, For-Hire Section, is the official custodian of the insuranee filings on behalf of all motor carriers under the jurisdiction of this Commission including Respondent's liability insurance filing.

3. The Respondent's certificate of liability coverage was canceled effective December 2, 2019.

4. By Order dated November 26, 2019, in Docket No. T-100, Sub 108, the Commission suspended Respondent's certificate of exemption effective December 2, 2019.

5. By Order dated January 7, 2020, in this docket, the Commission directed Respondent to appear before the Commission on February 7, 2020, and show cause, if any it had, why its certificate of exemption should not be cancelled for willful failure to maintain appropriate evidence of insurance on file.

6. The Respondent did not appear at the hearing on February 7, 2020, nor did anyone appear on its behalf.

7. The required liability insurance filing had not been made on Respondent's behalf at the time of the hearing.

WHEREUPON, the Hearing Examiner reaches the following

Conclusions

N.C.G.S. § 62-268 provides that no certificate or permit shall be issued or remain in force until the applicant shall have procured and filed with the Division of Motor Vehicles such insurance for the protection of the public as the Commission shall require. N.C. Gen. Stat. § 62-112 provides for the revocation of a franchise, after notice and hearing, for failure to provide and keep in force at all times insurance for the protection of the public.

IT IS, THEREFORE, ORDERED as follows:

1. That Certificate of Exemption No. C-2936 heretofore issued to Manco Carriers, LLC, d/b/a Manco Property Maintenance, be, and the same is hereby, revoked and cancelled; and

2. That a copy of this Order shall be sent to Respondent by Certified Mail, Return Receipt Requested.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of February, 2019 [2020].

NORTH CAROLINA UTILITIES COMMISSION
Kimberly A. Campbell, Chief Clerk

DOCKET NO. W-1302 SUB 4

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by YES AF Utilities EXP, LLC, For Approval of a Financing and Pledging of Assets	)))	ORDER DENYING REQUEST TO PLEDGE ASSETS

BY THE COMMISSION: On March 13, 2020, YES AF Utilities EXP, LLC (YES AF Utilities), filed a verified Application pursuant to N.C. Gen. Stat. § 62-160 et. seq. and Commission Rule R1-16 requesting Commission approval to pledge its utility assets in order to be a co-borrower on a $286 million credit facility, with an allocated loan amount of $8.1 million, in a proposed financing transaction as described in the Application and certain confidential loan documents filed thereto.

On April 8, 2020, the Commission issued an order pursuant to N.C.G.S. § 62-164 continuing this proceeding for the specific reasons set forth therein. Among other things, the order requested that the Public Staff investigate this matter and file the results of its investigation with recommendations as soon as the Application was sufficiently supplemented. YES AF Utilities filed information to supplement the Application on May 21, August 6, and October 21, 2020, and it filed a proposed order on November 6, 2020.

On November 30, 2020, the Public Staff filed its report stating that it has carefully reviewed the complex financing transaction and believes that the filings by YES AF Utilities provide the information to comply with Commission Rule R1-16 and N.C.G.S. § 62-161(b) and (c). Therefore, the Public Staff recommends that the Commission issue an order approving the proposed financing plan and pledging of assets.

Based upon the verified Application as supplemented and the Commission's entire files and records in this matter, the Commission now makes the following

FINDINGS OF FACT

1. YES AF Utilities is a Delaware limited liability company authorized to provide water and sewer utility service in the Autumn Forest Manufactured Housing Community (Autumn Forest) in Guilford County, North Carolina, pursuant to a certificate of public convenience and necessity granted by the Commission in Docket No. W-1302, Sub 0 on August 1, 2012. YES AF Utilities currently provides water and sewer service to approximately 300 customers and only serves Autumn Forest. Atlantic Environmental is the certified operator for YES AF Utilities.

2. The revenues and total assets of YES AF Utilities for the year ending December 31, 2019, were $80,987 and $102,948, respectively.

3. YES AF Utilities is wholly owned by YES Investors EXP, LLC, which in turn is wholly owned by YES Communities OP, L.P. (YES). YES is a privately held REIT that owns and manages over 210 manufactured housing communities in 18 states.

4. Autumn Forest is currently owned by YES Companies EXP, LLC, which is also owned by YES Investors EXP, LLC, and in turn, YES. Therefore, YES AF Utilities and Autumn Forest are affiliates and ultimately owned by YES.

5. The Application requests Commission approval to include YES AF Utilities as a co-borrower on a $286 million credit facility with the Federal Home Loan Mortgage Corporation (Freddie Mac). YES AF Utilities will be required to pledge its utility assets and will be jointly and severally liable with other co-borrowers, which are all affiliates of YES. The credit facility will be secured by 26 manufactured home communities in multiple states, including Autumn Forest.

6. The credit facility includes an allocated loan in the amount of $8.1 million for YES AF Utilities and Autumn Forest (the Loan), with net proceeds of $7.5 million. The Loan will be evidenced by a Loan and Security Agreement and secured by, among other things, a Multifamily Deed of Trust, Assignment of Leases and Rents, Security Agreement and Fixture Filing to be recorded against YES AF Utilities and Autumn Forest.

7. YES is the sole guarantor of the $286 million credit facility and the sole guarantor of the Loan to Autumn Forest and YES AF Utilities.

8. YES believes it is in the best interest of the company to enter into the Loan, and Freddie Mac requires that YES AF Utilities be a co-borrower under the Loan because it would not be feasible to own Autumn Forest without also owning YES AF Utilities. The Application states that YES AF Utilities is integral to the operation of Autumn Forest.

9. According to the Application as supplemented, proceeds from the Loan of approximately $8.1 million, with net proceeds of approximately $7.5 million, will be used for working capital and operating needs, including those in Autumn Forest and improvements to YES AF Utilities. For example, a portion of the net proceeds of the Loan to are anticipated to be used over the next couple of years to fund improvements and upgrades to the water and sewer systems, including a lift station upgrade, and to also complete roadwork and add a new pier and pavilion on the pond.

10. Pursuant to N.C.G.S. § 62-160 et. seq. and Commission Rule R1-16, YES AF Utilities asserts that the pledging of assets and financing plan applied for in the Application is (i) for some lawful object within the corporate purposes of the public utility, (ii) is compatible with the public interest, (iii) is necessary or appropriate for or consistent with the proper performance by such utility of its service to the public and will not impair its ability to perform that service, and (iv) is reasonably necessary and appropriate for such purpose.

Discussion and Conclusions

The Commission must decide the matters presented in the Application pursuant to N.C.G.S. §§ 62-160 and -161(a)-(c). Section 62-160 provides:

> No public utility shall pledge its faith, credit, moneys or property for the benefit of any holder of its preferred or common stocks or bonds, nor for any other business interest with which it may be affiliated through agents or holding companies or otherwise by the authority of the action of its stockholders, directors, or contract or other agents, the compliance or result of which would in any manner deplete, reduce, conceal, abstract or dissipate the earnings or assets thereof, decrease or increase its liabilities or assets, without first making application to the Commission and by order obtain its permission to do so.

Section 62-161 further provides:

> (a) No public utility shall issue any securities, or assume any liability or obligation as lessor, lessee, guarantor, indorser, surety, or otherwise, in respect to the securities of any other person unless and until, and then only to the extent that, upon application by such utility, and after investigation by the Commission of the purposes and uses of the proposed issue, and the proceeds thereof, or of the proposed assumption of obligation or liability in respect of the securities of any other person, the Commission by order authorizes such issue or assumption.
>
> (b) The Commission shall make such order only if it finds that such issue or assumption is (i) for some lawful object within the corporate purposes of the public utility, (ii) is compatible with the public interest, (iii) is necessary or appropriate for or consistent with the proper performance by such utility of its service to the public and will not impair its ability to perform that service, and (iv) is reasonably necessary and appropriate for such purpose.
>
> (c) Any such order of the Commission shall specify the purposes for which any such securities or the proceeds thereof may be used by the public utility making such application.

The Application requests Commission approval to pledge the assets of YES AF Utilities, a public utility providing essential water and sewer service in North Carolina and regulated under Chapter 62 of the North Carolina General Statutes, for both a $286 million credit facility, as a co-borrower jointly and severally liable with other affiliates of YES, and the Loan of approximately $8.1 million allocated to Autumn Forest and YES AF Utilities. YES, the ultimate parent company of YES AF Utilities, which owns and manages numerous manufactured housing communities in several states, has arranged this financing for its affiliates and regards the YES AF Utilities as an integral part of Autumn Forest. In addition, according to the Application, the lender requires that YES AF Utilities pledge its assets and be a co-borrower under the Loan, as it would not be feasible to own Autumn Forest without also owning YES AF Utilities. The total assets of YES AF Utilities are only approximately $100,000. According to the Application, proceeds of the $8.1 million Loan allocated to Autumn Forest and YES AF Utilities would be used for working capital and operating needs for not only the water and sewer systems of YES AF Utilities but also for Autumn Forest, such as roadwork and a new pier and pavilion on the pond. The only examples provided by the Application for which the proceeds would be used for the public utility purpose of YES AF Utilities were upgrades to the water and sewer systems, including a lift station upgrade, and no dollar figures or timetable were provided.

The Commission finds, contrary to the findings required by N.C.G.S. § 62-161(b) for approval, that the request of YES AF Utilities to pledge its utility assets for both the $286 million credit facility and $8.1 million Loan (i) is not for some lawful object within the corporate purposes of YES AF Utilities, (ii) is not compatible with the public interest, (iii) is not necessary or appropriate with the proper performance by YES AF Utilities of its service to the public and could impair its ability to perform that service, and (iv) is not reasonably necessary nor appropriate for such purpose. YES AF Utilities provides regulated and essential water and utility services to customers in North Carolina with approximately $100,000 of assets necessary to provide that service. The assets used by YES AF Utilities cannot be pledged to secure a loan for the benefit of nonregulated affiliates, including Autumn Forest and other affiliates operating in numerous states. Should default on the credit facility or Loan occur, both of which are far greater in amount than the assets or future needs of YES AF Utilities, the ability of the utility to operate could be placed in jeopardy. The Commission also notes that proceeds from the Loan are to be used by both YES AF Utilities and Autumn Forest, and no specific amounts or timetable were provided for any proceeds to be used only by YES AF Utilities.

The Commission understands that the ultimate parent company of YES AF Utilities, YES, has arranged a proposed financing which would appear to provide its subsidiaries with access to additional capital at reasonable rates. Further, the Commission understands that a lender wants to provide itself with all the security that it can obtain. However, the requested pledge of assets by the North Carolina regulated utility, YES AF Utilities, to be held jointly and severally liable for the credit facility and the Loan comingled with nonregulated affiliates of YES located in other states in amounts far greater than the capital needed by YES AF Utilities, is not permitted under N.C.G.S. §§ 62-160 and -160(a)-(c). The Commission, therefore, shall not approve and does not authorize the pledge of assets requested in the Application.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of December, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. W-218, SUB 497A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, for Approval of Semiannual Adjustments to Water and Sewer System Improvement Charges pursuant to N.C. Gen. Stat. § 62-133.12	))))))	ORDER APPROVING WATER AND SEWER SYSTEM IMPROVEMENT CHARGES ON A PROVISIONAL BASIS AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On November 1, 2019, Aqua North Carolina, Inc. (Aqua), filed an application requesting authority to adjust its Water System Improvement Charges (WSIC) and Sewer System Improvement Charges (SSIC) effective January 1, 2020, pursuant to Commission Rules R7-39 and R10-26 (Application).

On December 20, 2019, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a Notice of Public Staff's Plan to Present Comments and Recommendation (Notice) at the Commission's January 6, 2020 Regular Staff Conference. This Notice is incorporated by reference herein.

On January 6, 2020, Public Staff presented this matter to the Commission at Staff Conference.

On the basis of the verified Application, the records of the Commission, and the comments and recommendations of the Public Staff, the Commission makes the following

FINDINGS OF FACT

1. Aqua is a corporation duly organized under the laws of and is authorized to do business in the State of North Carolina. Aqua is a franchised public utility providing water and/or sewer utility service to customers in North Carolina.

2. Aqua's WSIC and SSIC percentages were reset to zero as of December 18, 2018, the effective date of Aqua's new base rates in its general rate case, Docket No. W-218, Sub 497 (Sub 497 Rate Case). This is Aqua's second filing to implement charges under the WSIC and SSIC mechanism since the Sub 497 Rate Case.

3. The implementation of the WSIC and SSIC for Aqua was first approved by the Commission on December 22, 2014, effective January 1, 2015. The WSIC and SSIC procedures allow for semiannual adjustments to Aqua's rates every January 1st and July 1st based upon reasonable and prudently incurred investment in eligible system improvements completed and placed in service prior to the filing of the request. This is Aqua's ninth semiannual adjustment to its WSIC and SSIC.

4. Aqua is requesting the following increases/decreases to the WSIC and SSIC percentages previously approved by the Commission on July 1, 2019:

	Previously Approved WSIC/SSIC Percentage	Net Change To WSIC/SSIC Percentage	Cumulative WSIC/SSIC Percentage
Uniform water	1.26%	1.37%	2.63%
Uniform sewer	0.39%	0.85%	1.24%
Fairways/Beau Rivage water	0.00%	0.00%	0.00%
Fairways/Beau Rivage sewer	0.18%	-0.01%	0.17%
Brookwood/LaGrange water	1.92%	1.61%	3.53%

5. The WSIC and SSIC percentages above do not include the Experience Modification Factor (EMF) adjustments from the 2018 annual WSIC and SSIC revenue review that went into effect on July 1, 2019. The impact of the 2018 EMF on Aqua's requested WSIC and SSIC percentages are as follows:

	WSIC/SSIC Percentage	2018 Experience Modification Factor	Cumulative WSIC/SSIC Percentage
Uniform water	2.63%	0.06%	2.69%
Uniform sewer	1.24%	-0.09%	1.15%
Fairways /Beau Rivage water	0.00%	-0.24%	-0.24%
Fairways/Beau Rivage sewer	0.17%	-0.11%	0.06%
Brookwood/LaGrange water	3.53%	0.04%	3.57%

6. The cumulative WSIC and SSIC revenue requirements after Aqua's proposed increases/decreases are as follows:

	Previously Approved WSIC/SSIC Revenue Requirement	Net Change to WSIC/SSIC Revenue Requirement	Cumulative WSIC/SSIC Revenue Requirement
Uniform water	$433,865	$484,479	$918,344
Uniform sewer	$58,207	$134,186	$192,393
Fairways/Beau Rivage water	$0	$0	$0
Fairways/Beau Rivage sewer	$3,834	$0	$3,834
Brookwood/LaGrange water	$104,769	$89,912	$194,681

7. Aqua is proposing the above increases/decreases in the WSIC and SSIC in order to recover the incremental depreciation and capital costs associated with the following WSIC and SSIC projects completed and placed in service from April 1, 2019, through September 30, 2019:

Secondary drinking water standards	$2,753,660
Main replacement	1,804,019
Primary drinking water standards	247,560
NCDOT water main relocate	237,426
Valves and hydrants	196,423
Service line replacement	62,573
Total WSIC plant additions	$5,301,661

Replace blowers and motors	$887,475
Replace lift station and sewer plant pumps	405,216
Total SSIC plant additions	$1,292,691

8. Under N.C. Gen. Stat. § 62-133.12(c), eligible water system improvements include "equipment and infrastructure installed at the direction of the Commission to comply with secondary drinking water standards." During the six months ended September 30, 2019, Aqua installed eight iron and manganese filter projects in the following subdivisions at a total cost of $2,753,660:

The Barony, Well #5	$386,963
Woodvalley, Well #9	261,471
Georges Grant, Well #1	430,080
Carlyle Manor, Well #4	360,167
Forest Glen, Well #2	322,148
Snow Creek Heights, Well #2	282,967
Kensington Manor, Well #2	396,083
Trappers Creek, Well #2	313,781
Total iron and manganese filter projects	$2,753,660

The Commission authorized the implementation of these filtration projects in its Order Approving Secondary Water Quality Improvement Projects issued on April 3, 2018, November 20, 2018, and December 17, 2018 in Docket No. W-218, Sub 363A and on May 20, 2019 in Docket No. W-218, Sub 497A.

9. Pursuant to N.C. Gen. Stat. § 62-133.12(g), the cumulative WSIC and SSIC percentages are capped at 5% of total annual service revenues approved by the Commission in the Sub 497 Rate Case, resulting in the following maximum revenue requirements for water and sewer operations:

	Sub 497 Annual Service Revenues	Maximum WSIC/SSIC Percentage	Maximum WSIC/SSIC Revenue Requirement
Uniform water	$35,345,847	x 5% =	$1,767,292
Uniform sewer	$14,330,238	x 5% =	$716,512
Fairways /Beau Rivage water	$1,077,223	x 5% =	$53,861
Fairways/Beau Rivage sewer	$2,084,779	x 5% =	$104,239
Brookwood/LaGrange water	$5,575,470	x 5% =	$278,774

As shown above, Aqua's proposed WSIC and SSIC revenue requirements do not exceed the maximum WSIC and SSIC revenue requirement for water and sewer operations.

10. As stated by the Commission in its June 6, 2014, Order Adopting Rules to Implement N.C. Gen. Stat. § 62-133.12, in Docket No. W-100, Sub 54, the Public Staff is to review all infrastructure improvements proposed for recovery for eligibility and reasonableness prior to making its recommendation to the Commission on WSIC or SSIC rate adjustments. Furthermore, any WSIC or SSIC rate adjustments will be allowed to become effective, but not unconditionally approved. These adjustments shall be further examined for a determination of their justness and reasonableness in a utility's next general rate case. At that time, the adjustments may be rescinded retroactively if the Commission determines that the adjustments were not prudent, just and/or reasonable.

11. Based on the Public Staff's investigation to date, the WSIC and SSIC projects included in Aqua's request are eligible water and sewer system improvements as defined in N.C. Gen. Stat. § 62-133.12(b), (c), and (d).

12. The Public Staff recommends the following adjustments to the WSIC and SSIC percentages:

(1) Revisions made to Uniform water project cost – In response to Public Staff data requests, Aqua provided to the Public Staff, a revised Appendix B for Uniform water operations reflecting a reduction of the total cost of several projects listed in the original filing. The combined reduction of these project costs is $9,193.

(2) Correct accumulated deferred income tax (ADIT) – Aqua inadvertently calculated tax depreciation on land acquired as part of the 2019 projects costs for Uniform water operations. This error was subsequently corrected by Aqua in the revised Appendix B provided to the Public Staff.

(3) Adjustment to Brookwood/LaGrange project cost – The Public Staff is recommending an adjustment to decrease the cost of the Strickland Road water main relocation project from $237,426 to $236,737 based on responses provided by Aqua to Public Staff data requests.

The effect of the adjustments discussed above reduces the overall revenue requirement for Uniform water and Brookwood/LaGrange water operations, however, Aqua's proposed WSIC percentages did not change based on the projected 2020 non-WSIC revenues.

13. Based on the adjustments above, the Public Staff recommends the following adjustments to the WSIC and SSIC revenue requirements and percentages proposed by Aqua:

	WSIC/SSIC Percentages Per Aqua	WSIC/SSIC Revenue Requirement Per Public Staff	Impact of Public Staff Adjustments	WSIC/SSIC Percentage Per Public Staff
Uniform water	2.69%	$481,459	0.00%	2.69%
Uniform sewer	1.15%	$134,186	0.00%	1.15%
Fairways/Beau Rivage water	-0.24%	$0	0.00%	-0.24%
Fairways/Beau Rivage sewer	0.06%	$0	0.00%	0.06%
Brookwood/LaGrange water	3.57%	$89,852	0.00%	3.57%

14. Based on the Public Staff's investigation to date, the Public Staff recommends that Aqua be allowed to implement the proposed WSIC and SSIC percentages effective for service rendered on or after January 1, 2020, subject to true-up. The Public Staff will continue to review the justness, prudency, and reasonableness of these improvements during its review of Aqua's future WSIC and SSIC filings and in Aqua's next general rate case.

CONCLUSIONS

Based upon the foregoing, the Commission concludes that Aqua should be allowed to implement the proposed increases/decreases in the WSIC and SSIC percentages effective for service rendered on and after January 1, 2020. These WSIC or SSIC rate adjustments, while allowed to become effective, are not unconditionally approved, and will be subject to further examination for justness and reasonableness in the WSIC and SSIC annual review and reconciliation and Aqua's next general rate case.

IT IS, THEREFORE, ORDERED as follows:

1. That Aqua is authorized to implement the recommended Water and Sewer System Improvement Charges set forth in the attached Appendix A-4 to Aqua's Schedule of Rates effective for service rendered on and after January 1, 2020, subject to true-up. The rates contained therein are provisional and subject to review in Aqua's next general rate case;

2. That the attached Appendix A-4 is approved and is deemed filed with the Commission pursuant to N.C. Gen. Stat. § 62-138; and

3. That Aqua shall mail to each of its customers with the next regularly scheduled customer billing the Commission-approved customer notice[1] and Aqua shall file the attached Certificate of Service, properly signed and notarized, not later than 45 days after the issuance of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of January, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Jeffrey A. Hughes did not participate in this decision.

APPENDIX A-4

AQUA NORTH CAROLINA, INC.
WATER AND SEWER SYSTEM IMPROVEMENT CHARGES

WATER SYSTEM IMPROVEMENT CHARGE

Aqua NC uniform water systems	2.69% 1/
Water systems in Brookwood and LaGrange service areas	3.57% 1/
Water systems in Fairways and Beau Rivage service areas	-0.24% 1/

SEWER SYSTEM IMPROVEMENT CHARGE

Aqua NC uniform sewer systems	1.15% 2/
Sewer systems in Fairways and Beau Rivage service areas	0.06% 2/

[1] Three separate customer notices are attached hereto as Attachments A, B, and C, respectively. The separate customer notices are intended to minimize customer confusion. Aqua shall mail the appropriate customer notice to each of its customers with the next regular customer billing.

WATER AND SEWER – FILINGS DUE PER ORDER

1/ The Water System Improvement Charge will be applied to the total water utility bill of each customer under the Company's applicable rates and charges.

2/ The Sewer System Improvement Charge will be applied to the total sewer utility bill of each customer under the Company's applicable rates and charges.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-218, Sub 497A on this the 6th day of January, 2020.

ATTACHMENT A
PAGE 1 OF 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 497A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	
202 MacKenan Court, Cary, North Carolina	)	NOTICE TO CUSTOMERS IN
27511, for Approval of Semiannual	)	BROOKWOOD / LAGRANGE
Adjustments to Water and Sewer System	)	SERVICE AREAS
Improvement Charges pursuant to N.C. Gen.	)	
Stat. § 62-133.12	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued an Order dated January 6, 2020, pursuant to N.C. Gen. Stat. § 62-133.12 and Commission Rules R7-39 and R10-26, authorizing Aqua North Carolina, Inc. (Aqua), to adjust its Water System Improvement Charge (WSIC) effective for service rendered on and after January 1, 2020, in Aqua's Brookwood/LaGrange service areas in Cumberland and Hoke Counties, in North Carolina.

By Order entered in Docket No. W-218, Sub 363, on May 2, 2014, the Commission approved Aqua's request, pursuant to N.C. Gen. Stat. § 62-133.12, for authority to implement a semiannual water and sewer system improvement charge (WSIC/SSIC) adjustment mechanism designed to recover the incremental costs associated with eligible investments in certain water and sewer infrastructure improvement projects completed and placed in service between general rate case proceedings. 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 Aqua's last general rate case. WSIC and SSIC charges for Aqua were first approved by the Commission on December 22, 2014, effective January 1, 2015. The WSIC and SSIC procedures allow for semiannual adjustments to Aqua's rates every January 1 and July 1.

The Public Staff – North Carolina Utilities Commission (Public Staff) has carefully reviewed Aqua's stated WSIC improvements, including reviewing in detail construction work in progress ledgers and transactions, invoices, work orders, engineering certifications and other accounting records. On December 20, 2019, the Public Staff filed

ATTACHMENT A
PAGE 2 OF 2

a Notice of Public Staff's Plan to Present Comments and Recommendations at the Commission's January 6, 2020 Regular Staff Conference (Notice).

Based on the application filed by Aqua and the Public Staff's Notice and recommendations, the Commission has approved the following WSIC charge for the Brookwood and LaGrange service areas, effective for service rendered on and after January 1, 2020:

	Previously Approved WSIC Percentage	Net Change To WSIC Percentage	Cumulative WSIC Percentage
WSIC	1.96%	1.61%	3.57%

The approved WSIC percentage of 3.57% will be applied to the water utility bill of each customer under Aqua's applicable service rates and charges.

The 3.57% WSIC percentage results in a $1.21 increase to the monthly average residential bill for a customer using the average of 5,306 gallons per month.

Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order dated May 2, 2014, in Docket No. W-218, Sub 363, the Commission's Order Adopting Rules to Implement N.C. Gen. Stat. § 62-133.12, dated June 6, 2014, in Docket No. W-100, Sub 54, the Aqua NC WSIC and SSIC Application filed November 1, 2019, the December 20, 2019, Public Staff Notice, and the January 6, 2020 Commission Order in Docket No. W-218, Sub 497A, all of which can be accessed from the Commission's website at www.ncuc.net, under Docket Portal, using the Docket Search feature for the docket numbers stated above (i.e., for Docket No. key: W-218 Sub 497A).

Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system through the Commission's website at www.ncuc.net.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of January, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

ATTACHMENT B
PAGE 1 OF 3

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 497A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, for Approval of Semiannual Adjustments to Water and Sewer System Improvement Charges pursuant to N.C. Gen. Stat. § 62-133.12	))))))	NOTICE TO CUSTOMERS IN FAIRWAYS AND BEAU RIVAGE SERVICE AREAS

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued an Order dated January 6, 2020, pursuant to N.C. Gen. Stat. § 62-133.12 and Commission Rules R7-39 and R10-26, authorizing Aqua North Carolina, Inc. (Aqua), to adjust its Water System Improvement Charge (WSIC) and Sewer System Improvement Charge (SSIC) effective for service rendered on and after January 1, 2020, in Aqua's Fairways and Beau Rivage service areas in New Hanover County, North Carolina.

By Order entered in Docket No. W-218, Sub 363, on May 2, 2014, the Commission approved Aqua's request, pursuant to N.C. Gen. Stat. § 62-133.12, for authority to implement a semiannual water and sewer system improvement charge (WSIC/SSIC) adjustment mechanism designed to recover the incremental costs associated with eligible investments in certain water and sewer infrastructure improvement projects completed and placed in service between general rate case proceedings. 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 Aqua's last general rate case. WSIC and SSIC charges for Aqua were first approved by the Commission on December 22, 2014, effective January 1, 2015. The WSIC and SSIC procedures allow for semiannual adjustments to Aqua's rates every January 1 and July 1.

ATTACHMENT B
PAGE 2 OF 3

The Public Staff – North Carolina Utilities Commission (Public Staff) has carefully reviewed Aqua's stated WSIC and SSIC improvements, including reviewing in detail construction work in progress ledgers and transactions, invoices, work orders, engineering certifications and other accounting records. On December 20, 2019, the Public Staff filed a Notice of Public Staff's Plan to Present Comments and Recommendations at the Commission's January 6, 2020 Regular Staff Conference (Notice).

Based on the application filed by Aqua and the Public Staff's Notice and recommendations, the Commission has approved the following WSIC and SSIC charge for the Fairways and Beau Rivage service areas, effective for service rendered on and after January 1, 2020:

	Previously Approved WSIC/SSIC Percentage	Net Change To WSIC/SSIC Percentage	Cumulative WSIC/SSIC Percentage
WSIC	-0.24%	0.00%	-0.24%
SSIC	0.07%	-0.01%	0.06%

The WSIC percentage of -0.24% will be applied to the water utility bill of each customer, and the SSIC percentage of 0.06% will be applied to the sewer utility bill of each customer, under Aqua's applicable service rates and charges.

The approved -0.24% WSIC percentage results in a $0.05 decrease to the monthly average residential bill for a customer using the average of 7,042 gallons per month. The -0.24% WSIC percentage also will apply to the monthly bills for the customers on water systems where Aqua purchases bulk water.

The 0.06% SSIC percentage results in a $0.04 increase to the monthly residential customer flat rate sewer bill.

Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order dated May 2, 2014, in Docket No. W-218, Sub 363, the Commission's Order Adopting Rules to Implement N.C. Gen. Stat. § 62-133.12, dated June 6, 2014, in Docket No. W-100, Sub 54, the Aqua NC WSIC/SSIC Application filed November 1, 2019, the December 20, 2019, Public Staff Notice, and the January 6, 2020 Commission Order in Docket No. W-218, Sub 497A, all of which can be accessed from the Commission's website at www.ncuc.net, under Docket Portal, using the Docket Search feature for the docket numbers stated above (i.e., for Docket No. key: W-218 Sub 497A).

ATTACHMENT B
PAGE 3 OF 3

Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system through the Commission's website at www.ncuc.net.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of January, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

ATTACHMENT C
PAGE 1 OF 3

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 497A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	
202 MacKenan Court, Cary, North Carolina	)	NOTICE TO CUSTOMERS
27511, for Approval of Semiannual	)	IN AQUA NORTH CAROLINA
Adjustments to Water and Sewer System	)	UNIFORM RATES SERVICE AREAS
Improvement Charges pursuant to N.C.	)	
Gen. Stat. § 62-133.12	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued an Order dated January 6, 2020, pursuant to N.C. Gen. Stat. § 62-133.12 and Commission Rules R7-39 and R10-26, authorizing Aqua North Carolina, Inc. (Aqua), to adjust its Water System Improvement Charge (WSIC) and Sewer System Improvement Charge (SSIC) effective for service rendered on and after January 1, 2020, in its service areas in North Carolina.

By Order entered in Docket No. W-218, Sub 363, on May 2, 2014, the Commission approved Aqua's request, pursuant to N.C. Gen. Stat. § 62-133.12, for authority to implement a semiannual water and sewer system improvement charge (WSIC/SSIC) adjustment mechanism designed to recover the incremental costs associated with eligible investments in certain water and sewer infrastructure improvement projects completed and placed in service between general rate case proceedings. 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 Aqua's last general rate case. WSIC and SSIC for Aqua were first approved by the Commission on December 22, 2014, effective January 1, 2015. The WSIC and SSIC procedures allow for semiannual adjustments to Aqua's rates every January 1 and July 1.

ATTACHMENT C
PAGE 2 OF 3

The Public Staff -- North Carolina Utilities Commission (Public Staff) has carefully reviewed Aqua's stated WSIC and SSIC improvements, including reviewing in detail construction work in progress ledgers and transactions, invoices, work orders, engineering certifications and other accounting records. On December 20, 2019, the Public Staff filed a Notice of Public Staff's Plan to Present Comments and Recommendations at the Commission's January 6, 2020 Regular Staff Conference (Notice).

Based on the application filed by Aqua and the Public Staff's Notice and recommendations, the Commission has approved the following WSIC and SSIC charge for the Aqua's uniform service areas, effective for service rendered on and after January 1, 2020:

	Previously Approved WSIC/SSIC Percentage	Net Change To WSIC/SSIC Percentage	Cumulative WSIC/SSIC Percentage
WSIC	1.32%	1.37%	2.69%
SSIC	0.30%	0.85%	1.15%

The WSIC percentage of 2.69% will be applied to the water utility bill of each customer, and the SSIC percentage of 1.15% will be applied to the sewer utility bill of each customer, under Aqua's applicable service rates and charges.

The approved 2.69% WSIC percentage results in a $1.30 increase to the monthly average residential bill for a customer using the average of 4,971 gallons per month. The 2.69% WSIC percentage also will apply to the monthly bills for the customers on water systems where Aqua purchases bulk water.

The approved 1.15% SSIC percentage results in a $0.83 increase to the monthly residential flat rate sewer bill. The 1.15% SSIC percentage will also apply to the monthly bills for metered sewer customers, including metered sewer customers on sewer systems where Aqua purchases bulk sewer treatment.

ATTACHMENT C
PAGE 3 OF 3

Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order dated May 2, 2014, in Docket No. W-218, Sub 363, the Commission's Order Adopting Rules to Implement N.C. Gen. Stat. § 62-133.12, dated June 6, 2014, in Docket No. W-100, Sub 54, the Aqua NC WSIC/SSIC Application filed November 1, 2019, the December 20, 2019, Public Staff Notice, and the January 6, 2020 Commission Order in Docket No. W-218, Sub 497A, all of which can be accessed from the Commission's website at www.ncuc.net, under Docket Portal, using the Docket Search feature for the docket numbers stated above (i.e., for Docket No. key: W-218 Sub 497A).

Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system through the Commission's website at www.ncuc.net.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of January, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

WATER AND SEWER – FILINGS DUE PER ORDER

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-218, Sub 497A, and the Notices were mailed or hand delivered by the date specified in the Order.

This the _____ day of __________________, 2020.

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-218, Sub 497A.

Witness my hand and notarial seal, this the ____ day of ______________, 2020.

____

Notary Public

____

Printed Name

(SEAL) My Commission Expires: ______________________________

Date

DOCKET NO. W-354, SUB 364A

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 Implement Water and Sewer System Improvement Surcharge Rate Adjustments Pursuant to N.C. Gen. Stat. § 62-133.12	)))))))	ORDER APPROVING WATER AND SEWER SYSTEM IMPROVEMENT CHARGES ON A PROVISIONAL BASIS AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On July 31, 2020, Carolina Water Service, Inc. of North Carolina (CWSNC or Company), filed an Application for approval of Water System Improvement Charge and Sewer System Improvement Charge (Application) rate adjustments effective October 1, 2020, pursuant to N.C. Gen. Stat. § 62-133.12, Commission Rules R7-39 and R10-26, and the WSIC/SSIC mechanisms, which were approved in CWSNC's general rate case, Docket No. W-354, Sub 336 (Sub 336 Rate Case) and in the Commission's prior orders approving Water System Improvement Charge (WSIC) and Sewer System Improvement Charge (SSIC) mechanisms for CWSNC.

On September 22, 2020, the Public Staff – North Carolina Utilities Commission (Public Staff) filed Notice of Public Staff's Plan to Present Comments and Recommendations at the Commission's October 5 Regular Staff Conference. On October 1, 2020, the Public Staff filed Request for Approval Letter and Proposed Order, wherein it requested the Commission decide the matter on the pleadings. CWSNC agreed with that protocol, requested time to respond, and on October 6, 2020, filed Response to Public Staff Recommendations Concerning Petition for Approval of Water and Sewer System Improvement Surcharge Rate Adjustments.

On November 3, 2020, the Commission issued an Order requiring CWSNC and the Public Staff to appear at Staff Conference on November 9, 2020, and containing written questions from the Commission in the attached Appendix A. On November 6, 2020, CWSNC and the Public Staff filed their respective responses to the Commission's written questions. On November 6, 2020, CWSNC and the Public Staff filed their respective responses to the Commission's questions. On November 9, 2020, representatives for both the Company and the Public Staff appeared at Staff Conference and answered the Commission's questions as ordered by the Commission.

On the basis of CWSNC's verified Application, historical records of the Commission, responses of CWSNC and the Public Staff, and the entire record herein, the Commission makes the following

FINDINGS OF FACT

1. CWSNC is a corporation duly organized under the laws of and is authorized to do business in the State of North Carolina. CWSNC is a franchised public utility providing water and sewer utility service to customers in North Carolina.

2. In the Sub 336 Rate Case Order dated March 10, 2014, the Commission approved CWSNC's request to utilize a WSIC/SSIC mechanism pursuant to N.C.G.S. § 62-133.12, concluding the mechanism is in the public interest, and established WSIC/SSIC procedures for CWSNC which allow for semiannual adjustments to CWSNC's rates every April 1st and October 1st based upon reasonable and prudently incurred investment in eligible system improvements completed and placed in service prior to the filing of the request.

3. CWSNC's WSIC/SSIC percentages were reset to zero as of March 31, 2020, the effective date of CWSNC's new base rates in its last general rate case in Docket No. W-354, Sub 364 (Sub 364 Rate Case).

4. The Application represents CWSNC's first filing to implement charges under the WSIC/SSIC mechanism since the Sub 364 Rate Case. CWSNC's request includes WSIC/SSIC improvements in the amount of $1,083,972 and $443,344, respectively, completed and placed in service during the six months ending June 30, 2020.

5. CWSNC's initially proposed WSIC and SSIC percentages for implementation on October 1, 2020, were as follows:

	WSIC/SSIC Revenue Requirements	Projected Service Revenues	Proposed WSIC/SSIC Percentages
Uniform Water	$116,046	$19,271,785	0.60%
Uniform Sewer	$54,827	$15,904,852	0.34%
BF/FH/TC Water	$2,734	$1,402,009	0.20%
BF/FH Sewer	$7,116	$2,243,027	0.32%

6. Pursuant to N.C.G.S. § 62-133.12(g), the cumulative WSIC/SSIC percentages are capped at 5% of the total annual service revenues approved by the Commission in the Sub 364 Rate Case, resulting in the following maximum revenue requirement for CWSNC's water and sewer operations which could be collected using WSIC/SSIC:

	Service Revenues	Cap Percentage	WSIC/SSIC Caps
Uniform Water	$19,271,785	X 5%	$963,589
Uniform Sewer	$15,904,852	X 5%	$795,243
BF/FH/TC Water	$ 1,402,009	X 5%	$ 70,100
BF/FH Sewer	$ 2,243,027	X 5%	$112,151

7. CWSNC's proposed revenue requirement does not exceed the maximum WSIC/SSIC revenue requirement listed above.

8. The Public Staff conducted its review of CWSNC's submitted WSIC/SSIC improvements, including a detailed review of construction work in progress ledgers and transactions, invoices, work orders, engineering certifications and other accounting records. Based on its review, the Public Staff recommends adjustments to remove entries it has determined are non-eligible water and sewer system improvement costs from CWSNC's WSIC/SSIC revenue requirement.

9. In its October 1, 2020 filing seeking a decision on the pleadings, the Public Staff recommends the following adjustments to the Company's proposed WSIC/SSIC percentages to reflect removal of costs it has determined are non-eligible for WSIC/SSIC recovery:

	WSIC/SSIC Percentages Including EMF Per CWSNC	WSIC/SSIC Revenue Requirements Per Public Staff	Impacts of Public Staff Adjustments	WSIC/SSIC Percentages Per Public Staff
Uniform Water	0.60%	$80,346	(0.18%)	0.42%
Uniform Sewer	0.35%	$38,152	(0.10%)	0.25%
BF/FH/TC Water	0.20%	$1,253	(0.11%)	0.09%
BF/FH Sewer	0.32%	$6,321	(0.04%)	0.28%

10. The WSIC/SSIC percentages recommended by the Public Staff result in the following increase to the average monthly metered and flat rate customer bill:

	Public Staff Recommended WSIC/SSIC Surcharges	Average Gallons Per Month	Average Monthly Bill	Monthly Surcharge	Monthly Bill With WSIC/SSIC Surcharge
Uniform Water - Metered	0.42%	3,608	$58.76	$0.25	$59.01
Uniform Water – Flat	0.42%	N/A	$58.54	$0.25	$58.79
Uniform Sewer - Metered	0.25%	3,569	$75.29	$0.19	$75.48
Uniform Sewer – Flat	0.25%	N/A	$73.73	$0.18	$73.91
BF/FH/TC Water - Metered	0.09%	4,128	$34.64	$0.03	$34.67
BF/FH Sewer – Flat	0.28%	N/A	$53.91	$0.15	$54.06

11. CWSNC agrees with a small portion of the adjustments recommended by the Public Staff but maintains that the plant costs excluded as ineligible by the Public Staff are eligible improvement costs appropriate for WSIC/SSIC recovery. CWSNC agrees with the Public Staff's adjustment to remove ineligible plant costs in the amount of $51,070 included in its Application, but maintains that additional plant costs in the amount of $433,902 disputed and disallowed by the Public Staff meet the criteria for eligibility set forth in both the WSIC/SSIC statute and in Commission Rules R7-39 and R10-26 for inclusion as eligible improvements.

12. The revised WSIC and SSIC percentages requested by CWSNC result in the following increase to the average monthly metered and flat rate customer bills:

	Commission Approved WSIC/SSIC Surcharges	Average Gallons Per Month	Average Monthly Bill	Monthly Surcharge	Monthly Bill With WSIC/SSIC Surcharge
Uniform Water – Metered	0.60%	3,608	$58.76	$0.35	$59.11
Uniform Water – Flat	0.60%	N/A	$58.54	$0.35	$58.89
Uniform Sewer – Metered	0.30%	3,569	$75.29	$0.23	$75.52
Uniform Sewer – Flat	0.30%	N/A	$73.73	$0.22	$73.95
BF/FH/TC Water – Metered	0.20%	4,128	$34.64	$0.07	$34.71
BF/FH Sewer – Flat	0.29%	N/A	$53.91	$0.16	$54.07

13. The water and sewer improvements recommended by the Public Staff for approval are appropriate for recovery using the WSIC/SSIC mechanism pursuant to N.C.G.S. § 62-113.12 and Commission Rules R7-39 and R10-26. The water and sewer improvements disputed by the Public Staff have not been shown to be appropriate for recovery using the WSIC/SSIC mechanism.

14. It is reasonable and appropriate that CWSNC retrospectively charge customers for the WSIC/SSIC surcharges approved herein through the experience modification factor (EMF) for the period October 1, 2020 through the date of this Order.

DISCUSSION AND CONCLUSIONS

When a utility files an application with the Commission for authority to impose a charge for water and sewer improvements pursuant to N.C.G.S. § 62-133.12, the Public Staff is required to review the application and make a recommendation to the Commission to either approve, modify, or reject the utility's proposed improvement charge. Order Adopting Rules to Implement 62-133.12, *Petition for Rulemaking to Implement G.S. 62-133.12*, No. W-100, Sub 54 (N.C.U.C. June 6, 2014)(Rulemaking Docket); Order Granting Partial Rate Increase, Approving Rate Adjustment Mechanism, and Requiring Customer Notice, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All Areas of North Carolina, Excluding Nags Head*, No. W-354, Sub 336 (N.C.U.C. March 10, 2014); Commission Rule R7-39(f); and Commission Rule R10-26(f). In the matter at hand, the Public Staff reviewed the Application and recommended by its filings of September 22, 2020 and October 1, 2020, that the Commission approve certain costs submitted for WSIC/SSIC recovery and deny certain other costs for improvements the Public Staff considers non-eligible for recovery using the WSIC/SSIC mechanism. With respect to the costs it found non-eligible, the Public Staff stated that "the non-eligible WSIC and SSIC projects were not system improvement projects, but were either routine maintenance and repairs or single service connections to CWSNC's water and sewer systems, which are not water and sewer system improvements as defined in N.C.G.S. § 62-133.12(b), (c) and (d)." Notice of Public Staff's Plan to Present Comments and Recommendations, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Implement Water and Sewer System Improvement Surcharge Rate Adjustments Pursuant to N.C. Gen. Stat. § 62-133.12*, No. W-354, Sub 364A (N.C.U.C. Sept. 22, 2020).

On October 6, 2020, CWSNC responded to the Public Staff's recommendation stating that the items disputed by the Public Staff are related to asset categories such as meters, meter installations, water service lines, water transmission and distribution mains, sewer gravity mains, and sewer services/laterals as are certain of the items recommended by the Public Staff for approval. The Company explained that the disputed improvements address issues that arise in the Company's water and sewer systems, such as main breaks, service line leaks, and stuck/slow/damaged or leaking meters and assemblies which are understood to be an inevitable part of operating a utility. CWSNC argued that these improvements represent investment in WSIC/SSIC-eligible replacements of assets that were required to enable the provision of safe, reliable, and efficient service in accordance with applicable water quality and effluent standards. As such, CWSNC maintained that the WSIC-eligible water system improvements included in its application were made pursuant to N.C.G.S. § 62-133.12(c)(1) and are qualifying in-kind replacements. CWSNC contended that the Public Staff is not justified in drawing distinctions between improvements falling in the same asset categories and finding some of them WSIC/SSIC-eligible and others non-eligible. The Company pointed out that WSIC/SSIC statutory eligibility criteria do not differentiate between "routine" or non-routine, nor between "project" or non-project improvements, and thus concluded that the Public Staff's reliance on these bases for eligibility is inapplicable under the law. According to CWSNC, "by a straightforward and reasonable reading of the WSIC/SSIC statute, these [disputed] investments meet the eligibility criteria of subsections (b), (c) and (d) of G.S. § 62-133.12."

The dispute between the Public Staff and the Company presents the Commission with the question of whether water and sewer system improvements that are properly capitalized on the utility's books as depreciable, used and useful assets and that are characterized as routine, unplanned or single customer service connections are eligible for investment recovery through the WSIC/SSIC mechanism. In accordance with the discussion to follow, the Commission determines that whether a water or sewer system improvement is routine or unplanned is not alone determinative of WSIC/SSIC eligibility, while an improvement benefitting only a single customer, as opposed to benefitting the utility's system, is not eligible for recovery using the WSIC/SSIC surcharge.

In deciding this matter, the Commission has reviewed the Application, the Public Staff's recommendation as filed on September 22, 2020 and October 1, 2020; CWSNC's response to the Public Staff's recommendation filed on October 6, 2020, the responses to Commission questions filed by the parties on November 6, 2020, the comments and representations made by the parties at the November 9, 2020 Staff Conference, N.C.G.S. § 62-133.12, Commission Rule R7-39, Commission Rule R10-26 and certain prior dockets and orders of the Commission with respect to the establishment of the existing Commission rules in effect for the WSIC/SSIC mechanism. Specific orders the Commission finds pertinent to the current WSIC/SSIC mechanism are: Order Adopting Rules to Implement 62-133.12, Docket No. W-100, Sub 54, dated June 6, 2014 (Rulemaking Order); Order Granting Partial Rate Increase, Docket No. W-354, Sub 336 dated March 10, 2014 (Sub 336 Rate Order); and Order Granting Partial Rate Increase, Docket No. W-218, Sub 363 dated May 2, 2014 (Aqua Rate Order). In the Rulemaking Docket, Aqua NC and Corix Regulated Utilities, Inc. (Corix), formerly known as Utilities, Inc. (collectively, the Utilities) filed joint comments on the Public Staff's proposed WSIC/SSIC rules, and ultimately, the Public Staff and the Utilities worked together to jointly recommend proposed WSIC/SSIC rules to implement the objectives of N.C.G.S. § 62-133.12. The Public Staff and the Utilities stated that they believed the recommended rules would ensure that the objectives of N.C.G.S. § 62-133.12 are maintained and provide for effective implementation, continued stringent regulatory review and oversight, and appropriate consumer protections. Further, the Public Staff and the Utilities noted that the semiannual adjustments they proposed would reasonably reduce regulatory lag, provide for efficient administration of these rate adjustments, and potentially increase the interval between general rate cases.

The Commission agrees with the statements made by the Public Staff and the Utilities in the Rulemaking Docket. The rules they recommended, as well as the rules as adopted by the Commission, were designed to provide for stringent regulatory review and oversight, appropriate consumer protections, efficient administration of WSIC/SSIC rate adjustments, reasonably reduced regulatory lag with respect to WSSIC/SSIC-eligible investments, and the potential for greater intervals between general rate cases.

Moreover, in the Rulemaking Order adopting the rules to implement the WSIC/SSIC mechanism, the Commission referred to the Aqua Rate Order and stated as follows:

The Commission believes that the primary purpose of G.S. 62-133.12 was to encourage and accelerate investment in needed water and sewer infrastructure by means of a mechanism which will alleviate the effects of regulatory lag by allowing for earlier recovery of some portion, not to exceed 5% of approved service revenues, of the incremental depreciation and capital costs associated with eligible investments made between general rate case proceedings. In accordance with G.S. 62-133.12, eligible water system and sewer system improvements would be installed, for example, to comply with primary drinking water standards, to implement solutions to wastewater problems, and to comply with State and federal law and regulations. Further, G.S. 62-133.12 allows, upon the Commission's specific direction, for the utility to implement solutions to comply with otherwise non-mandatory secondary water quality standards.

The Rulemaking Order further emphasized by referring to the Aqua Rate Order that the Commission considered the WSIC/SSIC mechanism to be a regulatory tool that would smooth the effect of rate increases stemming from needed infrastructure investments and could result in less frequent rate cases, which would have the effect of substantially reducing rate case expense. The Rulemaking Order also directed that the Public Staff would review and scrutinize improvement expenditures proposed to be recovered through the WSIC/SSIC surcharge. The Commission was clear in its statement from the Aqua Rate Order referenced in the Rulemaking Order that the Public Staff was charged with reviewing projected WSIC/SSIC costs *prior to* the utilities spending funds and requesting recovery from ratepayers using the WSIC/SSIC mechanism. The Public Staff's review would begin with the utility's filing of a three-year plan of proposed eligible system improvements. The Commission stated its expectation that the Public Staff's scrutiny and review of the ongoing three-year plan and the discussion of the plan with the utility between general rate cases would "provide the Public Staff with detailed information concerning eligible system improvement projects . . . and should also keep the Public Staff more informed [than it otherwise would be] regarding matters concerning the quality of service provided by [the utility] to its customers."

In adopting the rules to implement WSIC/SSIC recovery, the Commission included Commission Rules R7-39(c)(1)(a), (c)(1)(b) and (m) and R10-26(c)(1)(a), (c)(1)(b) and (m), which set forth the detailed requirements for the three-year plan required in a general rate case proceeding for the approval of a WSIC/SSIC mechanism and for the ongoing three-year plan requirement. In particular, Commission Rule R7-39 states that a utility seeking approval of a WSIC mechanism shall include in its application for a general rate increase a three-year plan.[1] Commission Rule R7-39(c)(1) requires a three-year plan that includes the following:

a. A detailed description of all proposed eligible water (sewer) system improvements expected to be completed in the initial WSIC (SSIC) Period and an estimate of the cost of the improvements and dates when the improvements will be placed into service; and

[1] Commission Rule R10-26 related to the SSIC has the same language.

b. A brief description of the proposed eligible water (sewer) system improvements, estimated costs, and completion dates for improvements that the utility plans to complete during the two years following the initial WSIC (SSIC) Period.

While Commission Rule R7-39(m) provides:

Ongoing Three-Year Plan. – Within 60 days following the end of each WSIC (SSIC) Period, the utility shall file an updated three-year plan containing the information prescribed in Section (c)(1) of this Rule and any other information required by the Commission.

Hence, the current WSIC/SSIC rules requiring the filing of a three-year plan provide the Public Staff with advance notice of the types of improvements, corresponding dollar amounts, and the timing of the improvements prior to the inclusion of such improvements in a WSIC/SSIC surcharge application. Additionally, the rules allow the Public Staff time to conduct a thorough review of the documentation provided in support of a recovery request. Further, the quarterly reports required pursuant to Commission Rules R7-39(n) and R10-26(n) include a Construction Status Report, which provides the Public Staff detailed information regarding WSIC/SSIC improvements that may potentially result in a future request for surcharge recovery.

For the semiannual surcharge application process to be a fluid process as intended by the WSIC/SSIC rules, there must be reasonable correlation between the improvements submitted by a utility in its application and the improvements included in its three-year plan. While the three-year plan is merely a planning tool and is subject to modifications by the utility for good cause, the Commission expects the utilities to apprise the Public Staff of any deviations between the eligible improvements included in its WSIC/SSIC application and the eligible improvements presented in its latest three-year plan on file with the Commission.

With regard to the pending Application, the Commission recognizes that CWSNC has presented a broader scope of improvements for WSIC/SSIC recovery following the Commission's encouragement in CWSNC's last general rate case that the Company make better use of the WSIC/SSIC mechanism as a tool for reducing regulatory lag for all system improvement projects allowed by N.C.G.S. § 62-133.12.[1] Further, the Commission observes that CWSNC has added categories to its three-year plan filed on May 28, 2020, such as, for example, "General Water System Replacements (Mains, Valves, Service Lines, Meters)." In taking steps to make better use of the WSIC/SSIC tool and adding a new category such as general system replacements, the Commission reminds CWSNC that it is required to provide the same level of specificity for all improvements for which it seeks surcharge recovery, including at a minimum, the information required by Commission Rule R7-39 or R10-26, as applicable. More specifically, the utility must provide the Public Staff with a sufficient level of detail to enable the Public Staff to evaluate improvements planned by the utility. A failure to provide a sufficient level of detail regarding

[1] Order Granting Partial Rate Increase and Requiring Customer Notice, *Application by Carolina Water Service, Inc., of North Carolina for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All of its Service Areas in North Carolina*, No. W-354, Sub 364 (N.C.U.C. Mar. 31, 2020).

improvements added to the three-year plan would undermine the streamlined WSIC/SSIC process approved by the Commission.

The Commission agrees with the Company that N.C.G.S. § 62-133.12 does not limit recovery to non-routine or planned system improvements. Rather, as further explained herein, certain system improvements that are unplanned or are replacements of existing or aging infrastructure could be WSIC/SSIC-eligible, if they are necessary to enable the provision of safe, reliable and efficient service in accordance with water quality and effluent standards and fall into one of the five categories of eligible system improvements enumerated in N.C.G.S. § 62-133.12(c). Moreover, with regard to improvements made in response to emergency situations, when larger infrastructure issues are discovered or cause the utility to accelerate a more comprehensive infrastructure improvement involving considerably more work than merely remedying the emergency situation, the WSIC/SSIC mechanism may be the proper route for revenue recovery.

The Commission notes that eligible system improvements must be of a magnitude or character such that recovery through the WSIC/SSIC mechanism continues to serve the public interest. The Commission notes that N.C.G.S. § 62-133.12(a) provides that a rate adjustment mechanism may only be approved upon the Commission's finding that such a mechanism is in the public interest. In the Sub 336 Rate Case Order, the Commission found that a WSIC/SSIC mechanism for use by CWSNC was in the public interest and to customer benefit, pointing out (1) that it would incentivize and encourage accelerated investment in infrastructure improvement allowing recovery, not exceeding 5% of approved service revenues, of incremental depreciation expense and capital cost associated with reasonable and prudent investment in eligible infrastructure improvements; (2) that it would incentivize the Company to undertake more extensive improvements to address secondary water quality issues making funds available where limited capital budget funds would otherwise be spent first on primary water quality improvements; (3) that the availability of funds collected through the use of the mechanism would encourage the Company to make improvements addressing secondary water quality standards sooner than it otherwise would; (4) that use of the mechanism would have a rate-smoothing effect, minimizing the impact of sharp rate increases experienced by customers when improvements are recovered at one time in general rate cases; and (5) that it could expand the interval between general rate case filings, alleviating the effects of regulatory lag and lessening rate case expense.

Thus, WSIC/SSIC-eligible system improvements should be consistent with the bases of the Commission's reasons set forth in the Sub 336 Rate Case Order for finding the WSIC/SSIC mechanism to be in the public interest. Otherwise, whether the use of the mechanism by the utility remains in the public interest would be called into question. To remain consistent with the Commission's determination that the use of the mechanism is in public interest, the Commission clarifies that an eligible water or sewer system improvement, routine or not, planned or not, must (1) be capitalized on the utility's books as a depreciable used and useful asset otherwise recoverable in a general rate case; (2) be included among the eligible system improvements listed in N.C.G.S. § 62-133.12(c) and (d); and (3) serve the purpose of potentially avoiding sudden sharp rate increases, accelerating infrastructure investments that would otherwise be delayed due to limited capital budget funds and foreseen lengthy regulatory lag, and increasing the time interval between general rate cases and lessening rate case expense. Moreover, the improvement must benefit the system. Certain improvements that benefit only a single customer may provide no benefit the system. To the extent an improvement benefits a sole customer or relatively few customers, it is not an eligible improvement unless the utility can demonstrate that the improvement provides some benefit to the system. Thus, not all spending, even on improvements that might be enumerated in N.C.G.S. § 62-133.12(c) and (d), necessarily meets the stated criteria.

The WSIC/SSIC mechanism was not intended to be a general replacement for recovery of all rate case eligible improvements. If all improvements were eligible for recovery using the WSIC/SSIC mechanism, it would be unlikely that the mechanism would encourage investment in improvements that are often delayed due to regulatory lag or due to the absence of sufficient funds to address discretionary issues such as secondary water quality. For example, if all rate case eligible improvements, without regard to the costs at issue, could be recovered using the WSIC/SSIC, the 5% service revenue cap quickly could be reached, leaving the mechanism unavailable as a tool to accelerate investment in the major improvements and also resulting in more frequent general rate cases.

Regarding the disputed improvements included in the Application representing $434,000 in investment, the Commission finds that CWSNC's Application and the supplemental information provided are not sufficient to establish that eligible system improvements are appropriate for cost recovery through the WSIC/SSIC mechanism. While the Company argues that the improvements at issue are capitalized and are among the type of improvements enumerated in N.C.G.S. § 62-133.12(c) and (d), the Public Staff maintains that some of the improvements would likely be considered maintenance and repairs expense in a general rate case proceeding. In its response to questions from the Commission filed on November 6, 2020, the Public Staff states that "[t]he majority of the costs that were excluded by the Public Staff were low cost items, less than $1,000." As previously stated, the Commission would not expect a utility to utilize the WSIC/SSIC mechanism simply to minimize all possible regulatory lag on any and all improvements. In the present docket, the Commission has not received sufficiently detailed descriptions of the improvements in dispute and the corresponding dollar amounts such that the Commission can determine whether all or some of the disputed costs are in fact eligible for recovery through the mechanism. Rather, the Commission was provided only the general description of the asset category and the corresponding total dollar amounts. In the future, should the Company bring specific improvements disputed by the Public Staff to the Commission for decision, the Company must provide the Commission with detailed descriptions of the improvements and supporting documentation it considers sufficient to demonstrate eligibility in accordance with the determinations and guidance set forth in this Order.

Going forward, to facilitate the Public Staff's and the Commission's review for WSIC/SSIC eligibility, the Company must present its newly added system improvement categories, such as, "General Water System Replacements" and "General Sewer System Mechanical Replacements" with the requisite specificity to satisfy Commission Rule R7-39 or Rule R10-26 as applicable and also include such specificity for these improvements in its three-year plan and surcharge applications. Further, CWSNC and the Public Staff should work cooperatively to determine the specific additional information that is necessary for the Public Staff's review, as well as how that information should be organized, in order to keep the WSIC/SSIC process operating efficiently.

Accordingly, for the reasons set forth herein, the Commission concludes that the WSIC/SSIC surcharges as proposed by the Public Staff in its October 1, 2020 letter filed with the Commission should be approved, effective for service rendered on and after the date of this Order. Further, the Commission concludes that CWSNC should be allowed to retrospectively charge customers for the approved surcharges through the EMF calculation as proposed by the Company in its November 12, 2020 filing and agreed to by the Public Staff for the period October 1, 2020 through the date of this order.

The Commission's decision herein does not in any way relieve CWSNC of its burden to prove that its investments are reasonable and prudently incurred as required by N.C.G.S. § 62-133.12 and Commission Rules R7-39 and R10-26. Moreover, these WSIC and SSIC rate adjustments, while allowed to become effective, are not unconditionally approved and will be subject to further examination for reasonableness and prudence in the WSIC and SSIC annual review and reconciliation and in CWSNC's next general rate case.

IT IS, THEREFORE, ORDERED as follows:

1. That CWSNC is authorized to implement the Water and Sewer System Improvement Charges set forth in the attached Appendix A-3 to CWSNC's Schedule of Rates effective for service rendered on and after the date of this Order, subject to true-up. The rates contained therein are provisional and subject to review in the WSIC and SSIC annual review and reconciliation and CWSNC's next general rate case;

2. That CWSNC shall be allowed to retrospectively charge customers for the approved surcharges through the EMF calculation for the period October 1, 2020 through the date of this Order;

3. That the attached Appendix A-3 is approved and is deemed filed with the Commission pursuant to N.C.G.S. § 62-138; and

4. That the Notice to Customers, attached hereto as Appendix B-3, shall be mailed with sufficient postage or hand delivered to all affected customers with the next regularly scheduled billing process.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of December, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Joann R. Snyder, Deputy Clerk

APPENDIX A

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA
WATER AND SEWER SYSTEM IMPROVEMENT CHARGES

WATER SYSTEM IMPROVEMENT CHARGE

All CWSNC Uniform water systems	0.42% [1/]
Bradfield Farms/Fairfield Harbour/Treasure Cove	0.09% [1/]

SEWER SYSTEM IMPROVEMENT CHARGE

All CWSNC Uniform sewer systems	0.25% [2/ and 3/]
Bradfield Farms/Fairfield Harbour	0.28% [2/]

<u>Notes</u>:

1/ The Water System Improvement Charge will be applied to the total water utility bill of each customer under the Company's applicable rates and charges.
2/ The Sewer System Improvement Charge will be applied to the total sewer utility bill of each customer under the Company's applicable rates and charges.
3/ These Water and Sewer Improvement Charges include the Experience Modification Factors that went into effect on October 1, 2020, and will cease on September 30, 2021.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 364A on this the 17th day of December,,2020.

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-354, SUBS 364A

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 Implement Water and Sewer System Improvement Surcharge Rate Adjustments Pursuant to N.C. Gen. Stat. § 62-133.12	)))))))	NOTICE TO CUSTOMERS

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued an Order dated December 17, 2020, pursuant to N.C. Gen. Stat. § 62-133.12 and Commission Rules R7-39 and R10-26, authorizing Carolina Water Service, Inc. of North Carolina (CWSNC) to implement a Water System Improvement Charge (WSIC) and Sewer System Improvement Charge (SSIC) for service rendered on and after the date of this Notice, in all its service areas in North Carolina. Further, CWSNC is authorized to retrospectively charge customers for the approved surcharges through the EMF calculation for the period October 1, 2020 through the date of this Notice.

By Order entered in Docket No. W-354, Sub 336 on March 10, 2014, the Commission approved CWSNC's request, pursuant to N.C.G.S. § 62-133.12, for authority to implement a semiannual water and sewer system improvement charge (WSIC and SSIC) adjustment mechanism designed to recover the incremental costs associated with eligible investments in certain water and sewer infrastructure improvement projects completed and placed in service between general rate case proceedings. The WSIC and SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC and SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in CWSNC's last general rate case. Commission Rules R7-39(h) and R10-26(h) specify that the WSIC and SSIC shall be applied to the total utility bill of each customer under the utility's applicable service rates and charges.

The Public Staff carefully reviewed CWSNC's WSIC and SSIC improvements, including, reviewing in detail construction work in progress ledgers and transactions, invoices, work orders, and other accounting records and recommends approval of certain of the adjustments proposed by CWSNC. Other adjustments, disputed between the

APPENDIX B
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Public Staff and CWSNC, have been thoroughly reviewed and evaluated by the Commission and were resolved by the approval of the charges shown below. The WSIC and SSIC percentages, including experience modification factors, approved by the Commission result in the following increase to the average monthly metered and flat rate customer bills:

	Commission Approved WSIC/SSIC Surcharge	Average Gallons Per Month	Average Monthly Bill	Monthly Surcharge	Monthly Bill With WSIC/SSIC Surcharge
Uniform Water – Metered	0.42%	3,608	$58.76	$0.25	$59.01
Uniform Water – Flat	0.42%	N/A	$58.54	$0.25	$58.79
Uniform Sewer – Metered	0.25%	3,569	$75.29	$0.19	$75.48
Uniform Sewer – Flat	0.25%	N/A	$73.73	$0.18	$73.91
BF/FH/TC Water – Metered	0.09%	4,128	$34.64	$0.03	$34.67
BF/FH Sewer – Flat	0.28%	N/A	$53.91	$0.15	$54.06

Additional information regarding the WSIC and SSIC mechanism is contained in the Commission's Order dated March 10, 2014, in Docket No. W-354, Sub 336; the Commission's Order Adopting Rules to Implement N.C.G.S. § 62-133.12, dated June 6, 2014, in Docket No. W-100, Sub 54; the CWSNC WSIC and SSIC Application filed July 31, 2020; the September 22, 2020 Public Staff Notice; the October 6, 2020 Response by CWSNC; the responses to Commission questions filed by CWSNC and the Public Staff on November 6, 2020; and the December 17, 2020 Commission Order in Docket No. W-354, Sub 364A, all of which can be accessed from the Commission's website at www.ncuc.net, under Docket Portal, using the Docket Search feature for the docket numbers stated above (i.e., for Docket No. enter: W-354 Sub 364A). Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system through the Commission's website.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of December, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Joann R. Snyder, Deputy Clerk

WATER AND SEWER – FILINGS DUE PER ORDER

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 No. W-354, Sub 364A, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of __________________, 2020.

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 ________________, 2020, in Docket No. W-354, Sub 364A.

Witness my hand and notarial seal, this the ____ day of ____________________, 2020.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ______________________________
Date

DOCKET NO. W-354, SUB 363
DOCKET NO. W-354, SUB 364
DOCKET NO. W-354, SUB 365

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. W-354, SUB 363

In the Matter of
Application by Carolina Water Service, Inc. of North Carolina, 4944 Parkway Plaza Boulevard, Suite 375, Charlotte, North Carolina, 28217, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricane Florence

DOCKET NO. W-354, SUB 364

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

DOCKET NO. W-354, SUB 365

In the Matter of
Application by Carolina Water Service, Inc. of North Carolina, 4944 Parkway Plaza Boulevard, Suite 375, Charlotte, North Carolina, 28217, for an Accounting Order to Defer Post-In-Service Depreciation and Financing Costs Related to Major New Projects That Are or Will Be In-Service Priorto the Date of An Order in Petitioner's Pending Base Rate Case

ORDER GRANTING PARTIAL RATE INCREASE AND REQUIRING CUSTOMER NOTICE

HEARD: Thursday, September 5, 2019, at 7:00 p.m., in Courtroom 5350, Mecklenburg County Courthouse, 832 East 4th Street, Charlotte, North Carolina

Tuesday, September 10, 2019, at 7:00 p.m., in Courtroom A, Dare County Courthouse, 962 Marshall C. Collins Drive, Manteo, North Carolina

WATER AND SEWER – MISCELLANEOUS

Tuesday, October 8, 2019, at 7:00 p.m., in Courtroom #1, Watauga County Courthouse, 842 W. King Street, Boone, North Carolina

Wednesday, October 9, 2019, at 7:00 p.m., in Courtroom 1A, Buncombe County Courthouse, 60 Court Plaza, Asheville, North Carolina

Monday, October 14, 2019, at 7:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Tuesday, October 22, 2019, at 7:00 p.m., in the Superior Courtroom, Onslow County Courthouse, 625 Court Street, Jacksonville, North Carolina

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

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

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

Mark R. Alson, Ice Miller LLP, One American Square, Suite 290, Indianapolis, Indiana 46282-0200

Christina D. Cress, Nichols, Choi & Lee, PLLC, 4700 Homewood Court, Suite 220, Raleigh, North Carolina 27609

For Corolla Light Community Association, Inc.:

Brady W. Allen, The 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, John Little, and William E. H. Creech, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: On January 17, 2019, in Docket No. W-354, Sub 363 (Sub 363) Carolina Water Service, Inc., of North Carolina (CWSNC or Company) filed a Petition for an Accounting Order to Defer Unplanned Incremental Hurricane Florence Storm Damage Expenses, Capital Investments, and Revenue Loss.

On May 24, 2019, pursuant to Commission Rule R1-17(a), CWSNC submitted notice of its intent to file a general rate case application in Docket No. W-354, Sub 364 (Sub 364).

On June 6, 2019, the Commission entered an order consolidating Sub 363 and Sub 364.

On June 28, 2019, CWSNC filed its verified application for a general rate increase (Application) in Sub 364 seeking authority to: (1) increase and adjust its rates for water and sewer utility service in all of its service areas in North Carolina, including the service areas of Riverbend Estates and Pace Utilities Group, Inc., which have been recently transferred to CWSNC; (2) consolidate rates for the Corolla Light/Monteray Shores (CLMS) service area with the Uniform Sewer Rate Division rates; and (3) pass through any increases in purchased bulk water rates and any increased costs of wastewater treatment performed by third parties and billed to CWSNC, all subject to CWSNC providing sufficient proof of such increases. In addition, the Company included as part of its rate case filing certain information and data required by NCUC Form W-1.

As part of the its Application CWSNC filed direct testimony of the following witnesses: Catherine E. Heigel, President of CWSNC, Tennessee Water Service, Inc., and Blue Granite Water Company;[1] Dante M. DeStefano, Director of Financial Planning and Analysis for CWSNC; Gordon R. Barefoot, President and CEO of Corix Infrastructure, Inc.;[2] J. Bryce Mendenhall, Vice President of Operations for CWSNC; Anthony Gray, Senior Financial and Regulatory Analyst, CWSNC; and Dylan W. D'Ascendis, Director at ScottMadden, Inc.

The Company stated in its Application that it presently has approximately 34,915 water customers and 21,403 sewer customers in North Carolina (including water and sewer availability customers).[3] The present rates for water and sewer service have been in effect since February 21, 2019, pursuant to the Commission's Order Approving Joint Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase and Requiring Customer Notice issued in CWSNC's last general rate case in Docket No. W-354, Sub 360 (Sub 360 Order).

On June 28, 2019, in Docket No. W-354, Sub 365 (Sub 365), CWSNC also filed a Petition for an Accounting Order to Defer Post-In-Service Depreciation and Financing Costs Relating to Major New Projects.

[1] On November 1, 2019, CWSNC filed notice that Donald H. Denton would adopt the prefiled direct testimony of Catherine E. Heigel.

[2] On November 8, 2019, CWSNC filed notice that Shawn Elicegui would adopt the prefiled direct testimony of Gordon R. Barefoot.

[3] The Company did not indicate the specific date related to its present number of customers statedin the Application. The number of customers presented in Finding of Fact No. 13 herein is based on the detailed billing analysis prepared by Public Staff witness Casselberry for the 12-month period ended March 31, 2019, and is not disputed by the Company.

On July 15, 2019, the Commission issued an Order Establishing General Rate Case and Suspending Rates. By that order, the Commission declared the matter to be a general rate case pursuant to N.C. Gen. Stat. § 62-137, suspended the proposed new rates for up to 270 days pursuant to N.C.G.S. § 62-134, and established the test year period for this case as the 12-month period ending March 31, 2019.

On August 2, 2019, the Commission issued an Order Scheduling Hearings and Requiring Customer Notice (Scheduling Order) which required the parties to prefile testimony and exhibits, scheduled the matter for hearing, and required notice to all affected customers. That order scheduled customer hearings to be held in Charlotte, Manteo, Boone, Asheville, Raleigh, and Jacksonville, North Carolina, and set the expert witness hearing to be held in Raleigh, North Carolina.

Also on August 2, 2019, CWSNC witness DeStefano filed supplemental testimony, and on August 23, 2019, CWSNC filed an amended exhibit to witness DeStefano's supplemental testimony.

On August 21, 2019, CWSNC filed a certificate of service demonstrating that the Company provided notice of this general rate case proceeding to customers as required by the Commission's Scheduling Order.

On August 22, 2019, Corolla Light Community Association, Inc. (CLCA), filed a Petition to Intervene, which the Commission granted by order dated September 5, 2019.

The Public Staff – North Carolina Utilities Commission's (Public Staff) participation in this proceeding is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

Public witness hearings were held as scheduled. A total of 23 Company customers testified as public witnesses at the public witness hearings held in this proceeding.

CWSNC responded to public witness testimony by its filings of September 25 (combined Charlotte and Manteo), October 24 (combined Boone and Asheville), October 30 (Raleigh), and November 8, 2019 (Jacksonville).

On October 4, 2019, CWSNC filed its rate case updates, schedules, and supporting data as required by Ordering Paragraph No. 6 of the Commission's Scheduling Order.

The Public Staff filed its direct testimony on November 4, 2019, consisting of testimony and exhibits of Public Staff witnesses Gina Y. Casselberry, Utilities Engineer, Water, Sewer, and Telephone Division; Charles M. Junis, Utilities Engineer, Water, Sewer, and Telephone Division; Lindsey Q. Darden, Utilities Engineer, Water, Sewer, and Telephone Division; Windley E. Henry, Manager, Water, Sewer, and Telephone Section, Accounting Division; Michelle M. Boswell, Staff Accountant, Accounting Division; Lynn L. Feasel, Staff Accountant, Accounting Division; and John R. Hinton, Director, Economic Research Division.

The Public Staff filed the supplemental testimony of witness Casselberry on November 15, 2019.

On November 15, 2019, the Company filed a request to consolidate Sub 365 with this rate case. The Commission issued an order consolidating Sub 364 and Sub 365 on November 19, 2019.

The Public Staff filed revised exhibits of Public Staff witnesses Feasel and Henry on November 18, 2019.

On November 18, 2019, CWSNC withdrew its request for consideration of the Company's proposed Consumption Adjustment Mechanism and Conservation Rate Pilot Program proposed for The Point Subdivision.

CWSNC filed the rebuttal testimony of Company witnesses DeStefano, Mendenhall, and D'Ascendis on November 20, 2019.

On November 26, 2019, Public Staff witness Hinton filed supplemental testimony and exhibits, revising his recommended rate of return on common equity and updating four exhibits filed with his testimony on November 4, 2019.

On November 27, 2019, CWSNC and the Public Staff (Stipulating Parties) filed a Joint Partial Settlement Agreement and Stipulation (Stipulation). On that date, the Public Staff also filed exhibits and supporting schedules for the Stipulation.

On December 2, 2019, CLCA filed a resolution opposing CWSNC's rate increase Application but requesting that CLMS' rates be set as part of CWSNC's uniform rate division.

The expert witness hearing was held as scheduled beginning on December 2, 2019. All prefiled testimony and exhibits filed in the consolidated dockets were admitted into evidence without objection. All parties agreed to waive cross-examination on all prefiled direct testimony with respect to the issues the parties resolved by Stipulation.

During the hearing the Commissioners requested certain additional information in the form of late-filed exhibits. The Public Staff filed the late-filed exhibits of Public Staff witnesses Casselberry and Henry on December 9 and 11, 2019, respectively. CWSNC filed the late-filed exhibits of Company witnesses DeStefano, D'Ascendis, and Mendenhall on December 13, 2019.

On January 10, 2020, CWSNC filed the affidavit of its Financial Planning and Analysis Manager, Matthew Schellinger, providing the updated amount of regulatory commission expense agreed to by CWSNC and the Public Staff.

On January 13, 2020, the Public Staff filed Revised Settlement Exhibits I and II providing the final expense information of CWSNC and the Public Staff's final revised recommendation.

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 laws of and is authorized to do business in the State of North Carolina. It is a franchised public utility providing water and sewer utility service to customers in 38 counties in North Carolina. CWSNC is a wholly-owned subsidiary of Corix Regulated Utilities, Inc. (Corix),[1] previously known as Utilities, Inc.

2. CWSNC is properly before the Commission pursuant to Chapter 62 of the North Carolina General Statutes for a determination of the justness and reasonableness of its proposed rates and charges for the water and sewer utility service it provides to customers in North Carolina.

3. The appropriate test year for use in this proceeding is the 12-month period ending March 31, 2019, updated for known and measurable changes through the close of the expert witness hearing.

4. CWSNC's present rates for water and sewer service have been in effect since February 21, 2019, pursuant to the Commission's Sub 360 Order.

The Stipulation

5. On November 27, 2019, the Stipulating Parties filed the Stipulation, resolving all but two of the contested issues between CWSNC and the Public Staff in this matter.

6. The Stipulation is the product of 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 who testified at the public witness hearings.

7. The Stipulation is a settlement of matters in controversy in this proceeding as between the Stipulating Parties and was not joined in nor objected to by CLCA, the other party to the proceeding.

8. The two remaining contested issues (Unsettled Issues) which were not resolved by the Stipulation between CWSNC and the Public Staff are:

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[1] Pursuant to the Articles of Amendment filed with the Illinois Secretary of State, Department of Business Services on July 25, 2019, Utilities Inc, changed its corporate name to Corix Regulated Utilities, Inc. Corix owns regulated utilities which provide water and sewer utility service to approximately 190,000 customers in 17 states, with primary service areas in Florida, North Carolina, South Carolina, Louisiana, and Nevada.

a. Rate of return on common equity; and

b. CWSNC's request for deferred accounting treatment of certain costs related to the Automatic Meter Reading (AMR) meter installation projects in the Fairfield Mountain and Connestee Falls systems.

Acceptance of Stipulation

9. 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.

10. The provisions of the Stipulation are just and reasonable to all parties to this proceeding, as well as the CWSNC ratepaying customers, and serve the public interest.

11. It is appropriate to approve the Stipulation in its entirety.

Customer Concerns and Service

12. As of the 12-month period ended March 31, 2019, CWSNC served approximately 30,724 water customers and 20,105 wastewater customers, including CLMS. For the same period, CWSNC also had 3,532 water availability customers in Carolina Forest, Woodrun, Linville Ridge, Sapphire Valley, Connestee Falls, and Fairfield Harbour; and 1,274 sewer availability customers in Sapphire Valley, Connestee Falls, and Fairfield Harbour. CWSNC operates 96 water utility systems and 37 sewer utility systems.

13. A total of 23 witnesses testified at the six public witness hearings held for the purpose of receiving customer testimony.[1] In general, public witness testimony at those hearings primarily dealt with objections to the rate increase with some customers raising concerns about quality of service, including, but not limited to, old equipment, delays in attention to meter repair, hardness of the water, digital meter boxes installed below the water table, boil water notices (including incidents and related communication), sewer spills in the lake at Connestee Falls, fluoride in the water, the ratio of base to fixed charges, response time to some inquiries, mineral content, the proposed Consumption Adjustment Mechanism, and the requirement of paying sewer charges while a home was unoccupied due to hurricane damage.

14. As of November 15, 2019, the Public Staff had received approximately 316 written customer statements of position from CWSNC customers. The service areas represented by those submitting such statements are: Belvedere (1), Brandywine Bay (2), Carolina Pines (1), Carolina Trace (11), Corolla Light/Monteray Shores (1), Connestee Falls (48), Fairfield Harbour (33), Kings Grant (1), Sapphire Valley (2), The Point (161), Treasure Cove (1), Ski Mountain

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[1] As noted above in the procedural history, there were no witnesses in Manteo, four in Charlotte, none in Boone, nine in Asheville, four in Raleigh, and six in Jacksonville.

(1) Waterglyn, (1) Woodhaven (1), and unspecified service areas (51).[1] All of the customers objected to the magnitude and frequency of the Company's rate increases. Their primary concern was that CWSNC's request for another rate increase was so soon after the most recent increase was granted in February 2019. Customers were also concerned about the rate of return on common equity requested, the increase in rates compared to inflation, the impact of recent federal corporate income tax reductions, and the ratio of the base facility charge to volumetric charges. The majority of the customers in The Point Subdivision opposed CWSNC's proposed Pilot Program.[2]

15. CWSNC filed four verified reports with the Commission addressing the service-related concerns and other comments by witnesses who testified at the public witness hearings. The reports described each of the witnesses' specific service-related concerns and comments, the Company's response, and how each concern and comment was resolved or addressed, if applicable.

16. The Company's customers in the Bradfield Farms Subdivision, Brandywine Bay, and the Fairfield Harbour Service Area testified to hardness of the water and unpleasant taste, conditions that are not regulated by the North Carolina Department of Environmental Quality (DEQ).

17. It is appropriate for CWSNC to provide an estimate of the cost of installing a central water filter system for Bradfield Farms Subdivision and the Fairfield Harbour Service Area, for the homeowners' association's consideration, within 60 days of the final order in this case, as recommended by the Public Staff.[3]

18. CWSNC has continued its course of increased attention to the communications component of service to customers since the Company's last rate case, with a positive emphasis on more proactive communications and the expansion of several social media platforms.

19. The Public Staff's description of the quality of service provided by CWSNC as "good" is supported by the record in this case.

20. The overall quality of service provided by CWSNC is adequate.

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[1] Approximately 80% of the customer statements came from four subdivisions or systems. Public Staff witness Casselberry testified that nearly all of the customers in The Point Subdivision opposed CWSNC's proposed Pilot Program.

[2] Public Staff witness Casselberry testified that the primary objections of customers at The Point Subdivision were that: (1) customers in The Point Subdivision were being penalized and that the block rates should apply to all CWSNC customers, (2) the average consumption did not take into account customers who live on the lake and use lake water for irrigation, (3) the covenants do not allow individual wells for irrigation, and (4) the conditions and rules for landscaping would increase the average bill by approximately 30% if the block tiered rates were approved.

[3] Public Staff witness Casselberry testified that in CWSNC's previous rate case, Sub 360, filed in 2018, the Public Staff investigated whether installing a central water filter system for Fairfield Harbour was a prudent investment. In that proceeding the Public Staff determined it was not a prudent investment because most customers had individual water softeners and filter systems in their homes and the cost in 2011 to install the system was approaching $1 million dollars. However, since it still remains an issue with customers at Fairfield Harbour and Bradfield Farms, the Public Staff recommended that if the majority of homeowners want a central water filter system, a monthly surcharge could be added to customer bills in those service areas to recover the costs for the systems.

WATER AND SEWER – MISCELLANEOUS

Rate Base

21. The appropriate level of rate base used and useful in providing service is $132,897,368 for CWSNC's combined operations, itemized as follows:

Item	Amount
Plant in service	$238,212,084
Accumulated depreciation	(57,897,943)
Net plant in service	180,314,141
Cash working capital	2,404,800
Contributions in aid of construction	(40,270,675)
Advances in aid of construction	(32,940)
Accumulated deferred income taxes	(5,995,444)
Customer deposits	(315,447)
Inventory	271,956
Gain on sale and flow back taxes	(417,811)
Plant acquisition adjustment	(837,878)
Excess book value	(0)
Cost-free capital	(261,499)
Average tax accruals	(143,198)
Regulatory liability for excess deferred taxes	(3,941,344)
Deferred charges	2,122,707
Pro forma plant	0
Original cost rate base	$132,897,368

Operating Revenues

22. The appropriate level of operating revenues under present rates for use in this proceeding is $33,968,582, consisting of service revenues of $33,852,232 and miscellaneous revenues of $387,492, reduced by uncollectibles of $271,142.

Maintenance and General Expense

23. The appropriate level of maintenance expense and general expense for combined operations for use in this proceeding is $14,897,501 and $6,560,142, respectively.

24. It is appropriate for CWSNC to recover total rate case expenses of $519,416 related to the current proceeding and $649,806 of unamortized rate case costs related to the prior proceedings in Docket Nos. W-354, Sub 356 (Sub 356) and W-354, Sub 360 (Sub 360).

25. It is appropriate to amortize the total rate case costs for the current and prior proceedings over five years and to include an annual level of costs in the amount of $73,911 related to miscellaneous regulatory matters, resulting in an annual level of rate case expense of $307,755, as agreed to by the Stipulating Parties.

WATER AND SEWER – MISCELLANEOUS

Storm Reserve Fund and Normalized Storm Damage Expense

26. It is reasonable and appropriate for CWSNC to include in rates an annualized level of storm expenses in its maintenance and repair expense, based on a ten-year average of the Company's actual storm costs. This is the first general rate case proceeding in which CWSNC has sought Commission approval of a normalized level of storm expenses to be included in base rates. As part of the Stipulation CWSNC and the Public Staff agreed that CWSNC would rescind its request for a storm reserve fund and that the calculation of normalized storm damage expense would be based on a ten-year average of the Company's actual storm costs rather than utilizing the Company's requested three-year average.

27. The appropriate annual amount of normalized storm costs that should be included in the Company's rates in this case is $34,567, as set out in the Stipulation.

Hurricane Florence Expense

28. It is reasonable and appropriate for CWSNC to include in rates the incremental operating and maintenance (O&M) costs amounting to $146,773 incurred by the Company related to Hurricane Florence.

29. The Company and the Public Staff have agreed to use deferral accounting treatment for Hurricane Florence storm-related expenses, which will be amortized over three years.

30. It is appropriate to include in the Company's maintenance and repair expense Hurricane Florence storm-related costs in the amount of $48,924, as set out in the Stipulation.

Deferral of Wastewater Treatment Plant and AMR Meter Installation Projects

31. In its Petition for an Accounting Order to Defer Post-In-Service Depreciation and Financing Costs Relating to Major New Projects in Sub 365 CWSNC requested deferral accounting treatment for post-in-service depreciation expense and financing costs (carrying costs) related to the Connestee Falls wastewater treatment plant (WWTP) project in Buncombe County; the Nags Head WWTP project in Dare County; the Fairfield Mountain AMR meter installation project in Transylvania County; and the Connestee Falls AMR meter installation project, also in Buncombe County.

32. During the test year for this rate case CWSNC earned a return on equity per books of 1.63% on a consolidated basis. The Company's current rates were set in the Sub 360 rate case effective for service rendered on and after February 21, 2019, based upon an authorized rate of return on common equity of 9.75%. CWSNC invested approximately $22 million of additional capital in its North Carolina water and sewer systems since the Sub 360 rate case, which served to depress its post-test year earned rate of return on common equity.

33. Each of the four capital projects covered by the Petition requesting deferral accounting treatment was completed and placed in service prior to the expert witness hearing in these proceedings. As evidenced by the Stipulation, CWSNC and the Public Staff agreed to the

Company's deferral of incremental post-in-service depreciation expense and financing costs of the two WWTP projects and to the amount of the costs to be included in the rate case.

34. The Public Staff did not agree to deferral accounting treatment for the incremental post-in-service depreciation expense and return on capital expenditures relating to the two AMR meter installation projects.

35. In this case the two WWTP projects subject to the Company's deferral request were prudent and necessary to the provision of service, and the costs for each of those projects were reasonable and prudently incurred. CWSNC and the Public Staff agree that the Company should be authorized to defer post-in-service costs of $1,098,778 for the two WWTP projects ($520,144 for Connestee Falls and $578,634 for Nags Head). CWSNC and the Public Staff also agree that the rate of return on common equity impact is 434 basis points for the Uniform Sewer Rate Division.

36. The project costs for each of the two WWTP projects, considered both collectively and singularly, are unusual or extraordinary in that they represent major capital investments in the Company's infrastructure; they are non-routine projects which are of considerable complexity and major significance; and they are necessary to CWSNC's provision of safe, adequate, reliable, and affordable utility service in this state. The WWTP costs are of a magnitude that would have an adverse material impact on the Company's financial condition if they are not afforded deferral accounting treatment.

37. It is reasonable and appropriate for CWSNC to receive deferral accounting treatment for the post-in-service depreciation expense and carrying costs related to the Company's capital investments in the WWTPs placed in service at Nags Head and Connestee Falls during the pendency of this proceeding.

38. The Company should be authorized to defer and amortize post-in-service depreciation expense and carrying costs in the amount of $1,098,778 related to its capital investments in the Nags Head and Connestee Falls WWTPs for the ten- and eight-month periods, respectively, from their in-service dates until the projects are included for recovery in base rates, as stipulated between CWSNC and the Public Staff. These costs should be amortized over a period of five years.

39. CWSNC expects significant ongoing capital needs at levels comparable to the $22 million additional capital it invested in its North Carolina water and sewer systems since the Sub 360 rate case. Deferral accounting treatment for the post-in-service costs related to the two WWTPs is appropriate to support the Company's ability to earn its authorized return and, as a result, could impact CWSNC's ability to finance needed investments on reasonable terms. Accordingly, deferral accounting treatment for the two WWTP costs will have a favorable impact on CWSNC's earnings and financial standing in general thereby enhancing the Company's ability to access and obtain capital on favorable terms and such results will accrue to the benefit of the Company's customers as well as to its investors.

40. The two AMR meter installation projects included in CWSNC's deferral accounting request were prudent and the costs for the installation were reasonable and prudently

incurred. CWSNC and the Public Staff agree that the rate of return on common equity impact is 24 basis points for the Uniform Water Rate Division.[1] CWSNC and the Public Staff also agree that the requested cost deferral amount related to the AMR meter installation costs is $64,736 for the eight-month period from their in-service dates until the projects are included for recovery in base rates in this case.

41. The two AMR meter installation projects in the Fairfield Mountain and Connestee Falls service areas are not unusual or extraordinary, and thus the incremental post-in-service depreciation expense and carrying costs related to the two projects are not appropriate for deferral accounting treatment.

Depreciation and Amortization Expense

42. The appropriate level of depreciation and amortization expense for combined operations for use in this proceeding is $5,026,554.

Franchise, Property, Payroll, and Other Taxes

43. The appropriate level of franchise, property, payroll, and other taxes for use in this proceeding is $795,507 for combined operations, consisting of ($655) for franchise and other taxes, $268,734 for property taxes, and $527,428 for payroll taxes.

Regulatory Fee and Income Taxes

44. It is reasonable and appropriate to calculate regulatory fee expense using the regulatory fee rate of 0.13% effective July 1, 2019, pursuant to the Commission's June 18, 2019 Order issued in Docket No. M-100, Sub 142. The appropriate level of regulatory fee for use in this proceeding is $44,159.

45. It is reasonable and appropriate to use the current North Carolina corporate income tax rate of 2.50% to calculate CWSNC's revenue requirement. The appropriate level of state income taxes for use in this proceeding is $75,474.

46. It is reasonable and appropriate to use the federal corporate income tax rate of 21.00% to calculate CWSNC's revenue requirement. The appropriate level of federal income taxes for use in this proceeding is $618,133.

47. It is appropriate to calculate income taxes for ratemaking purposes based on the adjusted level of revenues and expenses and the tax rates for utility operations.

[1] Calculated on a rate division basis, per Public Staff DeStefano Cross-Examination Exhibit 2. Thetotal company ROE impact is 13 basis points as shown on Public Staff witness Henry Late-Filed Exhibit 4,Line 9.

The Federal Tax Cuts and Jobs Act

48. CWSNC's federal protected EDIT should continue to be flowed back in accordance with the Reverse South Georgia Method (RSGM) as ordered by the Commission in the Sub 360 Order.

49. It is reasonable and appropriate, for purposes of this proceeding, for CWSNC to refund its remaining federal unprotected EDIT balances over 24 months instead of the remaining 35 months as originally ordered by the Commission in the Sub 360 Order.

50. CWSNC's North Carolina EDIT recorded pursuant to the Commission's May 13, 2014 Order Addressing the Impacts of HB 998 on North Carolina Public Utilities issued in Docket No. M-100, Sub 138 should continue to be amortized in accordance with the Commission's Sub 356 Order.

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

51. 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 7.39%. This overall rate of return is derived from applying an embedded cost of debt of 5.36%, and a rate of return on common equity of 9.50%, to a capital structure consisting of 50.90% long-term debt and 49.10% common equity.

52. A 9.50% rate of return on common equity for CWSNC is just and reasonable in this general rate case.

53. A 49.10% equity and 50.90% debt ratio is a reasonable and appropriate capital structure for CWSNC in this case.

54. A 5.36% cost of debt for CWSNC is reasonable and appropriate for the purpose of this case.

55. Any increase in the Company's rate for service will be difficult for some of CWSNC's customers to pay, in particular for those considered to be low-income customers.

56. Continuous safe, adequate, reliable, and affordable water and wastewater utility service by CWSNC is essential to CWSNC's customers.

57. The rate of return on common 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.

58. The 9.50% rate of return on common equity and the 49.10% equity capital structure approved by the Commission balance CWSNC's need to obtain equity and debtfinancing with its customers' need to pay the lowest possible rates.

59. The authorized levels of overall rate of return and rate of return on commonequity 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

60. CWSNC's rates should be changed by amounts which, after all pro forma adjustments, will produce the following increases in revenues:

Item	Amount
CWSNC Uniform Water	$ 1,778,015
CWSNC Uniform Sewer	2,929,386
BF/FH/TC Water	96,561
BF/FH Sewer	141,797
Total	$4,945,759

These increases will allow CWSNC the opportunity to earn a 7.39% overall rate of return,which the Commission has found to be reasonable upon consideration of the findings in this order.

Rate Design

61. Regarding the CLMS sewer service area, CWSNC has maintained the CLMS system at the same rates for the last four general rate cases (Docket No. W-354, Subs 336, 344, 356, and 360) in order to allow the remainder of the Uniform Sewer RateDivision to move toward parity with the CLMS sewer rates. In this proceeding the Company proposes to consolidate the CLMS sewer service area rates with the Uniform Sewer Rate Division rates, as the total Uniform Sewer revenue requirement is currently sufficient to allow for such consolidation of rate structures. It is reasonable and appropriate at this time to consolidate the CLMS sewer service area rates with the Company's Uniform Sewer rates. This rate design is supported by both the Public Staff and CLCA.

62. It is reasonable and appropriate for CWSNC's rate design for water utility service for its Uniform Water and Bradfield Farms/Fairfield Harbour/Treasure Cove (BF/FH/TC) Water residential customers to be based on a 50/50 ratio of base charge to usage charge, and to use an 80/20 ratio of base charge to usage charge for CWSNC's Uniform Sewer residential customers, as set out in the Stipulation.

63. The rates and charges included in Appendices A-1 and A-2, and the Schedules of Connection Fees for Uniform Water and Uniform Sewer, attached hereto asAppendices B-1 and B-2, are just and reasonable and should be approved.

WATER AND SEWER – MISCELLANEOUS

Water and Sewer System Improvement Charges

64. 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.

65. 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.

Recommendations of the Public Staff

66. It is reasonable and appropriate for the Company, in its next general rate case filing, to ensure that its NCUC Form W-1, Item 26 has been carefully reviewed so that the filing does not include double bills, that the Company accounts for multi-unit customers, and that other bills produced, such as final bills, late notices, re-bills, or other miscellaneous bills, are not included in the filing.

67. It is reasonable to approve an increase in the Company's reconnection fee from $27.00 to $42.00.

68. The connection charge of $1,080 for water and $1,400 for sewer for Winston Pointe Subdivision, Phase IA, recommended by the Public Staff is reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1–4

General Matters

The evidence supporting these findings of fact is found in the verified 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. 5–11

The Stipulation and Acceptance of Stipulation

The evidence supporting these findings of fact is found in the Stipulation, the testimony of both CWSNC's and the Public Staff's witnesses, the affidavit of Matthew Schellinger, and Revised Settlement Exhibits I and II.

On November 27, 2019, CWSNC and the Public Staff entered into and filed a Partial Settlement Agreement and Stipulation, which memorializes their agreements on some of the issues in this proceeding. Attached to the Stipulation is Settlement Exhibit 1, which demonstrates the impact of the Stipulating Parties' agreements on the calculation of CWSNC's gross revenue for the test year ended March 31, 2019. Thus, the Stipulation is based upon the same test period as the Company'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 expert witness hearing. In addition to the Stipulating 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, and 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 provides that it is binding as between CWSNC and the Public Staff, and that it is 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. During the expert witness hearing in response to a question from the Commission, CLCA indicated that it has no objection to the Stipulation. Tr. vol. 9, 200–01. There are no other parties to this proceeding.

The key aspects of the Stipulation are as follows:

- ***Tariff Rate Design*** – The Stipulating Parties agree that rate design in this case should be based on a 50/50 ratio of fixed/volumetric revenues for the Uniform Water and BF/FH/TC Water residential customers and an 80/20 ratio of fixed/volumetric revenues for the Uniform Sewer residential customers.

- ***Capital Structure*** – The Stipulating Parties agree that the capital structure appropriate for use in this proceeding is a capital structure consisting of 49.10% common equity and 50.90% long-term debt at a cost of 5.36%.

- ***Property Insurance Expense*** – The Stipulating Parties agree to the Company's rebuttal position of $279,912.

- ***Treatment of Water Service Corporation (WSC) Rent Expense*** – The Stipulating Parties agree to the Public Staff's calculation of WSC's rent expense for its Chicago, Illinois office lease as reflected in Revised Feasel Exhibit I, Schedule 3-11.

- ***Water Loss Adjustment for Purchased Water Expense*** – The Stipulating Parties agree upon a 20% water loss threshold for Whispering Pines, Zemosa Acres, Woodrun, High Vista, and Carolina Forest subdivisions.

- ***Purchase Acquisition Adjustment (PAA) Amortization Expense Rates*** – The Company agrees to the Public Staff's PAA amortization rates per Revised Feasel Exhibit I, Schedule 3-15.

- ***Storm Reserve Fund and Storm Expense*** – The Company agrees to rescind its request to implement its proposed Storm Reserve Fund, and to utilize the Public Staff's position per Revised Feasel Exhibit I, Schedule 3-4.

- ***Application of Hurricane Florence Insurance Proceeds*** – The Public Staff agrees to the Company's rebuttal position removing insurance overpayments to date from the insurer.

WATER AND SEWER – MISCELLANEOUS

- *Accumulated Deferred Income Taxes (ADIT)* - The Company agrees to the Public Staff's proposed calculations of ADIT regarding unamortized rate case expense. The Stipulating Parties agree to revise ADIT for any updates made to rate case expense deferrals.

- *Deferral Accounting for Capital Investments in WWTPs* - The Stipulating Parties agree that deferral accounting treatment for post-in-service depreciation expense and carrying costs related to the Company's capital investments in WWTPs placed in service at Nags Head and Connestee Falls during the pendency of this proceeding is reasonable and appropriate.

- *Regulatory Commission Expense* - The Stipulating Parties agree 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 41, for actual and estimated costs once supporting documentation is provided by the Company. The Stipulating Parties agreed to amortize rate case expenses for a five-year period.

- *Revenue Requirement* – The Stipulating Parties agree to certain other revenue requirement issues designated as "Settled Items" on Settlement Exhibit 1, which was attached to the Stipulation and is incorporated by reference therein.

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 the Court to subject the Commission's order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. *CUCA II*, 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation "requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] . . . satisf[y] the requirements of [C]hapter 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 17.

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 give-and-take in 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 the testimony and supporting exhibits of Public Staff witnesses Henry and Feasel 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, some of which were more important to CWSNC and, others of which 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, CLCA, and the public witnesses who testified at the hearings.

In addition, the Commission finds that the Stipulation is a nonunanimous 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) rate of return on common equity; and (2) the deferral of expenses related to the installation of AMR meters in the Company's Fairfield Mountain and Connestee Falls service areas.

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 reasonable terms, on the one hand, and its customers to receive safe, adequate, reliable, and affordable 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. 12-20

Customer Concerns and Service

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 and Mendenhall, and in the verified reports filed by CWSNC in response to the concerns testified to by the public witnesses at hearings.

WATER AND SEWER – MISCELLANEOUS

On June 28, 2019, 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 34,915 water customers and 21,403 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.

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
September 5, 2019	Charlotte	William Colyer Rachel Fields, William Michael Wade, and James Sylvester
September 10, 2019	Manteo	None
October 8, 2019	Boone	None
October 9, 2019	Asheville	Chuck Van Rens, Jack Zinselmeier, Jeff Geisler, Phil Reitano, Jeannie Moore, Linda Huber, Brian McCarthy, Ron Shuping, and Steve Walker
October 14, 2019	Raleigh	Alfred Rushatz, Vince Roy, Mark Gibson, andDavid Smoak
October 22, 2019	Jacksonville	Danny Conner, Ralph Tridico, James C. Kraft,John Gumbel, David Stevenson, and Irving Joffee

Public Staff witness Casselberry testified that her investigation included a review of customer complaints, contact with the DEQ Division of Water Resources (DWR) and Public Water Supply Section (PWSS), review of Company records, and analysis of revenues at existing and proposed rates. Tr. vol. 8, 78. Witness Casselberry testified that she contacted the seven regional offices in North Carolina. The PWSS identified four water systems – Riverwood, Meadow Glen, Wood Trace, and Sapphire Valley – which required action by CWSNC; DWR identified three wastewater treatment plants – CLMS, Carolina Trace, and Asheley Hills – which required action by CWSNC. Witness Casselberry investigated each concern and testified that CWSNC has taken the necessary actions and that the Public Staff is satisfied that the concerns reported by PWSS and DWR have been addressed or are in the process of being resolved. Tr. vol. 8, 81.

In addition, witness Casselberry testified that she had reviewed approximately 316 consumer statements of position from CWSNC customers received by the Public Staff as a result of this proceeding. Witness Casselberry stated that the service areas represented by those submitting statements are Belvedere (1), Brandywine Bay (2), Carolina Pines (1), Carolina

Trace (11), Corolla Light/Monteray Shores (1), Connestee Falls (48), Fairfield Harbour (33), Kings Grant (1), Sapphire Valley (2), The Point (161), Treasure Cove (1), Ski Mountain (1), Waterglyn (1), Woodhaven (1), and unspecified service areas (51). Tr. vol. 8, 96. She testified that all customers objected to the magnitude of the rate increase. She indicated that public witnesses' primary concern was that CWSNC's request for another rate increase was filed just four months after it had been granted an increase in rates in February 2019. Most of the customers in Connestee Falls said there was no justification for such a large increase, that they had to pay the base charge for service when they were not occupying their homes, and that they experienced numerous leaks and boil water advisory notices over the summer. The customers in Fairfield Harbour said that they were still recovering from Hurricane Florence and that they could not afford an increase. They also stated that the water quality was poor and that they had to install individual softeners and filter systems. Nearly all of the customers in The Point Subdivision opposed CWSNC's proposed Pilot Program. Their primary objections were that (1) customers in The Point were being penalized, and that the block rates should apply to all CWSNC customers, (2) the average consumption did not take into account customers who live on the lake and use lake water for irrigation, the covenants do not allow individual wells for irrigation, and (4) the conditions and rules for landscaping would increase the average bill by approximately 30 percent if the block tiered rates were approved. Tr. vol. 8, 96–101. Customer concerns were addressed in Public Staff witness Casselberry's supplemental testimony filed on November 15, 2019.

Witness Casselberry also testified regarding service and water quality complaints registered by customers at each of the five public hearings. Tr. vol. 8, 111. She stated that she had read each of the four reports filed by CWSNC in response to the customer concerns and complaints which were included in testimony at the public hearings. Witness Casselberry testified that there were a few isolated service issues which the Company had addressed or was in the process of resolving.

After reviewing the testimony and complaints of the customers regarding water quality and hardness in the Fairfield Harbour and Bradfield Farms service areas, witness Casselberry stated CWSNC should provide an estimate of the cost of installing a central water filter system for Bradfield Farms Subdivision, Tr. vol. 8, 102–03, and the Fairfield Harbour Service Area, Tr. vol. 8, 109–110, for the homeowners' associations' consideration.

With the exception of her recommendation for Bradfield Farms Subdivision and the Fairfield Harbour Service Area, witness Casselberry had no additional comments or recommendations. Tr. vol. 8, 111. She testified that CWSNC's quality of service is good. Tr. vol. 8, 111. Witness Casselberry also testified that the quality of water meets the standards set forth by the Safe Drinking Water Act and is satisfactory. Tr. vol. 8, 111.

With regard to the concerns expressed by customers about the Company's proposed Pilot Program to test conservation rates in The Point Subdivision, the Commission acknowledges that this matter is no longer an issue in this proceeding because CWSNC withdrew its request for authority to implement its proposed Pilot Program on November 18, 2019. CWSNC stated its withdrawal of the Pilot Program was based on the Public Staff's opposition to CWSNC's proposed Pilot Program in the present case and the existence of the Commission's generic rate design proceeding in Docket No. W-100, Sub 59 (Sub 59). CWSNC noted that the Company will continue to actively participate in the Commission's Sub 59 generic rate design proceeding to explore and consider rate design proposals that may better achieve the Company's desire for revenue sufficiency and stability, while also sending appropriate signals to consumers that support and encourage water efficiency and conservation.

Additionally, in CWSNC's November 18, 2019 filing, the Company withdrew its request for the consumption adjustment mechanism (CAM) proposed in this proceeding. CWSNC stated its withdrawal for the CAM was prompted by the Commission's initiation of a rulemaking proceeding in Docket No. W-100, Sub 61 on November 14, 2019; the Public Staff's testimony in this matter recommending that the Commission deny CWSNC's request to implement a CAM; and the Company's expectation that other water and wastewater providers will seek to have input on the implementation of any CAM guidelines. CWSNC maintained that the contested issues concerning the requested CAM are more suitable for resolution in the generic proceeding than in this rate case proceeding.

Based upon the foregoing, and after careful review of the testimony of the customers at the public hearings, the Company's reports on customer comments, the Public Staff's engineering and service quality investigation, and the late-filed exhibits submitted by CWSNC and the Public Staff, the Commission concludes that, consistent with the statutory requirements of N.C.G.S. § 62-131(b), the overall quality of service provided by CWSNC is adequate, efficient, and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

Rate Base

The evidence supporting this finding of fact is found in the verified Application and the accompanying NCUC Form W-1, the testimony of Company witness DeStefano, the testimony of Public Staff witnesses Feasel and Henry, the Stipulation, and Revised Settlement Exhibits I and II.

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 Per Application	Difference	Amount Per Public Staff
Plant in service	$217,460,239	$20,751,845	$238,212,084
Accumulated depreciation	($55,739,757)	($2,158,186)	($57,897,943)
Net plant in service	161,720,483	18,593,659	180,314,141
Cash working capital	2,467,676	(62,876)	2,404,800
Contributions in aid of construct.	(40,916,105)	645,430	(40,270,675)
Advances in aid of construction	(32,940)	0	(32,940)
Accum. deferred income taxes	(6,699,939)	704,495	(5,995,444)
Customer deposits	(304,114)	(11,333)	(315,447)
Inventory	271,956	0	271,956
Gain on sale and flow back taxes	(131,695)	(286,116)	(417,811)
Plant acquisition adjustment	(873,734)	35,856	(837,878)
Excess book value	(331)	331	0
Cost-free capital	(261,499)	0	(261,499)
Average tax accruals	125,013	(268,211)	(143,198)
Regulatory liability for EDIT	(3,941,344)	0	(3,941,344)
Deferred charges	2,252,645	(129,938)	2,122,707
Pro forma plant	17,195,228	(17,195,228)	0
Original cost rate base	$130,871,300	$2,026,068	$132,897,368

On the basis of the Stipulation and revisions made by the Public Staff in its Revised Settlement Exhibits I and II, the Company and the Public Staff are in agreement concerning all components of rate base except for the amount of cash working capital. Therefore, the Commission finds that the uncontested adjustments to rate base recommended by the Public Staff are appropriate adjustments to be made in this proceeding.

CWSNC and the Public Staff disagree on the amount of cash working capital to include in rate base for use in this proceeding due to the unsettled issue concerning the deferral accounting treatment of the AMR meter installation projects in Fairfield Mountain and Connestee Falls. Based on the testimony of Company witness DeStefano, CWSNC disagrees with the Public Staff's recommendation to deny deferral accounting treatment for the two AMR meter installation projects. As a result of their differing positions concerning this issue and its effect on their respective recommended level of maintenance and repair expense, CWSNC and the Public Staff recommend different amounts for cash working capital to include in rate base, $2,406,418 and $2,404,800, respectively.

Based on the conclusions reached elsewhere in this order concerning the deferral accounting treatment for AMR meter installation projects in Fairfield Mountain and Connestee Falls, the Commission concludes that the appropriate amount for cash working capital is $2,404,800. Consequently, the appropriate level of rate base for combined operations for use in this proceeding is as follows:

WATER AND SEWER – MISCELLANEOUS

Item	Amount
Plant in service	$238,212,084
Accumulated depreciation	($57,897,943)
Net plant in service	180,314,141
Cash working capital	2,404,800
Contributions in aid of construction	(40,270,675)
Advances in aid of construction	(32,940)
Accumulated deferred income taxes	(5,995,444)
Customer deposits	(315,447)
Inventory	271,956
Gain on sale and flow back taxes	(417,811)
Plant acquisition adjustment	(837,878)
Excess book value	0
Cost-free capital	(261,499)
Average tax accruals	(143,198)
Regulatory liability for excess deferred taxes	(3,941,344)
Deferred charges	2,122,707
Pro forma plant	0
Original cost rate base	$132,897,368

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

Operating Revenues

The evidence supporting this finding of fact is found in the testimony of Public Staff witnesses Feasel 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 per Application	Difference	Amount per Public Staff
Operating Revenues:			
Service revenues	$33,269,517	$582,715	$33,852,232
Miscellaneous revenues	353,280	34,212	387,492
Uncollectible accounts	(246,348)	(24,794)	(271,142)
Total operating revenues	$33,376,449	$592,133	$33,968,582

Based on the Stipulation and the revisions made by the Public Staff in its Feasel Revised Exhibits I and II, the Company does not dispute the following Public Staff adjustments to operating revenues under present rates:

WATER AND SEWER – MISCELLANEOUS

Item	Amount
Reflect pro forma level of service revenues	$582,715
Adjustment to forfeited discounts	10,128
Adjustment to sale of utility property	24,084
Adjustment to uncollectible accounts	(24,794)
Total	$592,133

For reasons discussed elsewhere in this order, the Commission has found that the adjustments listed above are appropriate adjustments to be made to operating revenues under present rates in this proceeding.

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	$33,852,232
Miscellaneous revenues	387,492
Uncollectible accounts	(271,142)
Total operating revenues	$33,968,582

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 23-25

Maintenance and General Expenses

The evidence for these findings of fact is found in the verified Application and the accompanying NCUC Form W-1; the testimony of Public Staff witnesses Feasel, Henry, and Darden; the testimony of Company witnesses DeStefano and Mendenhall; the affidavit of Matthew Schellinger; and the Revised Settlement Exhibits I and II.

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 Per Application	Difference	Amount Per Public Staff
Maintenance Expenses:			
Salaries and wages	$5,143,430	($193,719)	$4,949,710
Purchased power	2,110,722	(7,679)	2,103,043
Purchased water & sewer	2,171,965	47,278	2,219,243
Maintenance and repair	2,955,315	165,620	3,120,935
Maintenance testing	546,264	(1,832)	544,432
Meter reading	206,176	0	206,176
Chemicals	713,452	(19,856)	693,596
Transportation	539,115	(4,915)	534,200
Operating expenses charged to plant	(615,663)	(49,470)	(665,133)
Outside services - other	1,219,715	(28,417)	1,191,299
Total maintenance expenses	$14,990,492	($92,991)	$14,897,501
General Expenses:			
Salaries and wages	$2,386,901	($382,491)	$2,004,409
Office supplies and other office expense	569,400	(536)	568,864
Regulatory commission expense	303,485	4,269	307,754
Pension and other benefits	1,531,096	69,062	1,600,158
Rent	392,552	(62,244)	330,308
Insurance	664,043	118,519	782,562
Office utilities	751,728	(4,058)	747,670
Miscellaneous	355,931	(137,513)	218,417
Total general expenses	$6,955,135	($394,993)	$6,560,142

Regulatory Commission Expense

In his January 10, 2020 affidavit, Matthew Schellinger provided an amount of $519,416 for the actual costs incurred to date and the estimated expense to be incurred related to this rate case. Affiant Schellinger requested that the Commission approve total rate case costs of $1,169,222 to be amortized over five years. He stated that the $1,169,222 includes $649,806 for unamortized rate case expense from prior proceedings plus $519,416 related to this case. Affiant Schellinger commented that the annual amortization expense for rate case costs for this proceeding total $233,844 ($1,169,222 amortized over five years). Affiant Schellinger also requested that the Commission include in regulatory commission expense an annual amount of $73,911 in miscellaneous regulatory costs for filings and compliance type activities not directly related to rate case costs. He maintained that these expenses are a direct cost of service, are not disputed, and were agreed upon between CWSNC and the Public Staff in the Stipulation. In sum, Affiant Schellinger requested that the Commission include a total annual amount of $307,755 in regulatory commission expense in this proceeding, consisting of rate case costs of $233,844 and miscellaneous regulatory costs of $73,911.

The Public Staff stated that it has reviewed the invoices and other supporting documents along with the rate case expense spreadsheet provided by CWSNC and found that the types of rate case expense in this rate case matched the nature of the expense in prior rate cases and the amount of these expenses in the current proceeding are appropriate and reasonable to be included in this rate case. The Public Staff and the Company are in agreement that the miscellaneous regulatory matters costs in the Company's books as provided in the affidavit of Matthew Schellinger should also be included as regulatory commission expense to be recovered in this rate case as a reasonable cost of service incurred by CWSNC. Therefore, in light of the foregoing the Commission finds that it is appropriate and reasonable to amortize the sum of the total rate case costs of $519,416 for the current proceeding and the unamortized rate case cost balance of $649,806 from the prior rate cases over five years and to include an annual level of costs in the amount of $73,911 related to miscellaneous regulatory matters, resulting in an annual level of regulatory commission expense of $307,755 to be recovered in this proceeding.

On the basis of the Stipulation and revisions made by the Public Staff in Henry Revised Exhibit I, Feasel Revised Exhibits I and II, and Revised Settlement Exhibits I and II, the Company and the Public Staff are in agreement concerning all adjustments recommended by the Public Staff to maintenance and general expenses except for maintenance and repair expense. Therefore, the Commission finds that the uncontested adjustments to maintenance and general expenses recommended by the Public Staff are appropriate adjustments to be made in this proceeding.

CWSNC and the Public Staff disagree on the amount of maintenance and repair expense to include in maintenance and general expenses in this proceeding due to the unsettled issue concerning the deferral accounting treatment of the AMR meter installation projects in Fairfield Mountain and Connestee Falls. Based on the testimony of Company witness DeStefano, CWSNC disagrees with the Public Staff's recommendation to deny deferral accounting treatment for the two AMR meter installation projects. As a result of their differing positions concerning this issue, CWSNC and the Public Staff recommend differing amounts for maintenance and repair expense, $3,133,882[1] and $3,120,935, respectively. The Company included an amount of $12,947 ($64,736 amortized over five years) in maintenance and repair expense related to its requested deferral accounting treatment for the two AMR meter installation projects whereas the Public Staff did not.

Based on the conclusions reached elsewhere in this Order concerning the deferral accounting treatment for the AMR meter installation projects in Fairfield Mountain and Connestee Falls, the Commission concludes that the appropriate level of maintenance and repair expense for combined operations for use in this proceeding is $3,120,935.

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[1] See page 160 of the Company's proposed order filed on January 10, 2020, in these dockets which includes the agreed-upon pro forma adjustments per the Stipulation and CWSNC's recommendations concerning the two unsettled issues in this rate case.

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	$4,949,710
Purchased power	2,103,043
Purchased sewer	2,219,243
Maintenance and repair	3,120,935
Maintenance testing	544,432
Meter reading	206,176
Chemicals	693,596
Transportation	534,200
Operation exp. charged to plant	(665,133)
Outside services - other	1,191,299
Total maintenance expenses	$14,897,50
General Expenses:	
Salaries and wages	$2,004,409
Office supplies and other officeexpense	568,864
Regulatory commission expense	307,754
Pension and other benefits	1,600,158
Rent	330,308
Insurance	782,562
Office utilities	747,670
Miscellaneous	218,417
Total general expenses	$6,560,142

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26-27

Storm Reserve Fund and Normalized Storm Damage Expense

The evidence for these findings of fact is found in the verified Application and the accompanying NCUC Form W-1, the testimony of Public Staff witnesses Feasel and Henry, and the Stipulation and Revised Settlement Exhibits I and II.

In the Company's Application, it requested to establish a storm reserve fund to support extraordinary O&M costs resulting from damages sustained in severe storms such as Hurricane Florence. CWSNC witness DeStefano testified that CWSNC proposesto create a monthly, flat surcharge for each active customer's water and sewer service bill until the reserve threshold of $250,000 is reached. Witness DeStefano commented that CWSNC proposed to collect a monthly surcharge of $0.42 per customer per month based on the threshold of $250,000. In addition, this is the first general rate case proceeding in which CWSNC seeks Commission approval of a normalized level of stormexpenses to be included in base rates. In NCUC Form W-1, Item 10, Schedule 24, the Company used three years (2016–2018) to calculate the average storm cost requested to be recovered in this rate case. Witness DeStefano maintained that the storm reserve fund would only be utilized if the Company's storm costs for the last 12 months exceed the level of normalized storm expenses included in the base rate revenue requirement.

Public Staff witness Henry testified that in addition to the storm reserve fund, CWSNC applied to include in rates a normalized level of storm expense calculated using a three-year average of actual storm expenses incurred, excluding Hurricane Florence expenses. Witness Henry stated that ten years has historically been used to calculate the average storm cost because a ten-year time period would include some years in which storm costs were high and others in which they were low, resulting in a more reasonable average than that which would result from using only the three most recent years. Additionally, witness Henry stated that using a ten-year time period has been approved by the Commission in prior decisions. For the reasons set forth in his prefiled testimony, witness Henry recommends that the Commission deny CWSNC's request for a storm reserve fund. In the Stipulation the Company agreed to rescind its request to implement its proposed storm reserve fund and also agreed to the Public Staff's use of a ten-year average for storm costs. The Stipulating Parties have agreed to a normalized level of storm expenses in the amount of $34,567, to be included in maintenance and repair expense.

Therefore, in light of the foregoing the Commission concludes that it is appropriate and reasonable to continue its historical practice of using a ten-year time period as the standard for calculating average annualized storm costs to be recovered in the Company's rates as an ongoing level of expense. Consequently, the appropriate annual level of normalized storm costs that should be included in CWSNC's rates in this proceeding is $34,567, as set out in the Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 28-30

Hurricane Florence Expense

The evidence supporting these findings of fact is found in the Company's Petition for Accounting Order in Sub 363, the testimony of Company witness DeStefano, the testimony of Public Staff witnesses Henry and Feasel, the Stipulation, Settlement Exhibit I, and Revised Settlement Exhibits I and II in Sub 364.

On January 17, 2019, CWSNC filed a Petition for an Accounting Order to Defer Unplanned Incremental Hurricane Florence Storm Damage Expenses, Capital Investments, and Revenue Loss in Sub 363 requesting an accounting order authorizing it to establish a regulatory asset and defer until the Company's next general rate case costs incurred in connection with damage to the Company's water and wastewater systems resulting from the impacts of Hurricane Florence. Additionally, the Company sought Commission approval to defer O&M costs, lost revenues, and depreciation expense on its capital investments. According to the Sub 363 Petition, CWSNC's facilities suffered extensive damage due to the storm, particularly in the coastal region of the Company's service territory.

CWSNC stated that it incurred extraordinary, unplanned operating and capital costs, as well as lost revenues from customers who were forced to disconnect their service due to damage to their homes. Additionally, the Company provided invoices to the Public Staff showing that it has incurred, to date, $146,773 in storm-related incremental O&M expenses, $582,570 in capital investments, and $46,320 in estimated revenue loss. In its comments filed on April 4, 2019, the

Public Staff did not object to CWSNC's recovery of a substantial portion of its 2018 verified storm O&M costs and deferral accounting treatment for the incremental O&M costs related to Hurricane Florence; however, it opposed CWSNC's request to defer depreciation expense associated with the Company's capital investments and lost revenues. Additionally, the Public Staff recommended that the amortization period begin as of October 2018, the date of the storm, and not begin with the effective date of the Company's next general rate case, which is the instant case, Sub 364, filed on June 28, 2019.

After considering prior cases and the tests applied by the Commission, the Public Staff determined that "the damage to CWSNC's system from Hurricane Florence was greater than that caused by any other storm in the Company's history, which will affect the Company's rate of return on common equity. The Public Staff concluded that this is an exceptional circumstance justifying some deferral of costs." Public Staff's Sub 363 Comments. However, in opposing CWSNC's request to defer depreciation expense associated with the Company's capital costs and lost revenues, the Public Staff cited the Commission's order in the last Duke Energy Progress, LLC. (DEP), general rate case, Docket No. E-2, Sub 1142, where DEP's request for deferral of depreciation expense, return on the undepreciated balance of capital costs, and the carrying costs on the entirety of the deferred costs was denied.

The Public Staff, therefore, recommends the following:

(a) that the Commission approve a deferral of $146,773 in 2018 Hurricane Florence storm O&M expenses, but no deferral of CWSNC's depreciation expense or lost revenues;
(b) that CWSNC be required to amortize the costs deferred over a three-year period beginning in October 2018;
(c) that upon final determination of the actual amount of costs of Hurricane Florence the Company be required to file a final accounting of said costs with the Commission for review and approval;
(d) that approval of this accounting procedure is without prejudice to the right of any party to take issue with the amount of or the ratemaking treatment accorded these costs in any future regulatory proceeding; and
(e) that any applicable insurance proceeds received by CWSNC will be used to offset the deferred O&M expenses.

As shown in Settlement Exhibit I, witness Feasel calculated a total deferral amount of $146,773 for the incremental O&M costs related to the 2018 storm costs with an amortization period of three years beginning in October 2018, using the procedure recommended by witness Henry. The Company and the Public Staff agree to the amount of Hurricane Florence storm-related costs included in Settlement Exhibit I as noted in the Stipulation.

The Commission finds and concludes that it is just and reasonable for the Company to receive deferral accounting treatment for the incremental O&M costs amounting to $146,773 in Hurricane Florence storm costs and that these costs should be amortized over three years. Consequently, it is appropriate to include in CWSNC's maintenance and repair expense Hurricane Florence storm-related costs in the amount of $48,924, as set out in the Stipulation.

WATER AND SEWER – MISCELLANEOUS

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 31-41

Deferral of WWTP Projects and AMR Meter Installation Projects

The evidence for these findings of fact is found in the record of Sub 365, including the initial comments of the Public Staff and the reply comments of the Company; the testimony of Company witnesses DeStefano and Mendenhall; the testimony and exhibits of Public Staff witnesses Henry, Feasel, and Junis; the Stipulation, and Revised Settlement Exhibits I and II.

Summary of the Evidence

On June 28, 2019, contemporaneously with the Sub 364 rate case application, the Company filed a Petition for an Accounting Order to Defer Post-In-Service Depreciation and Financing Costs Relating to Major New Projects in Sub 365.

On September 20, 2019, the Public Staff filed comments, and on October 21, 2019, CWSNC filed reply comments. On November 15, 2019, the Company filed a motion to consolidate the Sub 365 docket with the Sub 364 rate case proceeding, which was granted by Commission order dated November 19, 2019.

In its Sub 365 petition, CWSNC describes four major new projects that were in progress and would be placed in service after the close of the test year but during the pendency of this general rate case proceeding. The Company requests authority to defer the incremental post-in-service depreciation expense and financing costs of those projects and then to recover those costs in the rates approved in Sub 364, amortized over a five-year period. The four projects are:

(a) Connestee Falls WWTP in Buncombe County;
(b) Nags Head WWTP in Dare County;
(c) Fairfield Mountain AMR meters installed in Transylvania County; and
(d) Connestee Falls AMR meters installed in Buncombe County.

CWSNC witness DeStefano's testimony explained that the accounting and cost recovery treatment of these projects would have a material impact on the Company's ability to earn its authorized return from its last rate case. The Company requests deferral of incremental post-in-service depreciation expense and financing costs on these four projects from their respective in-service dates until the projects are included for recovery in base rates in this case.

Company witness Mendenhall described the four projects. He stated that the Connestee Falls WWTP project involved the installation of a "sequencing batch reactors" treatment facility which replaced a 300,000 gallons per day (gpd) concrete plant installed in the early 1970s. He noted that the plant is located in the mountains and exposed to winter weather, including cold, ice, and snow. These conditions led to the serious erosion of exposed areas of concrete, most significantly the above-the-waterline walls and walkways, due to years of "freeze/thaw" cycles. Witness Mendenhall maintained that the concrete deterioration had reached the point of "end of life" of the asset and that the old plant presented a high risk of failure. He stated that the build-out needs of the community require 460,000 gpd of wastewater treatment capacity and that the new plant was built adjacent to the existing plant. He commented that the cost of the project was $7,177,326 and that it was placed in-service on July 31, 2019.

Witness Mendenhall testified that the Nags Head WWTP project consisted of the installation of a new membrane treatment facility to allow for effluent disposal below permitted nitrate levels in groundwater monitoring wells. He explained that the purpose of this project was to modify the existing Aeromod 0.400 million gallon per day (mgd) plant with membrane filtration to provide reuse-quality effluent to meet groundwater nitrate and total dissolved solids (TDS) compliance testing limits. Witness Mendenhall noted that in 2018, the Division of Water Quality, DEQ, issued a Notice of Violation requiring the plant to comply with current groundwater testing limits of 500 mg/L for TDS and 5 mg/L for nitrates. He stated that the previous plant met the wastewater treatment plant effluent limits but was unable to meet the newly imposed groundwater limits for the monitoring wells. Witness Mendenhall maintained that had the new facility not been constructed, the risk of imposition of severe penalties or a consent decree was high. He noted that the cost of the project was $6,876,116, and it was placed in-service on May 31, 2019.

Witness Mendenhall further stated that in 2019, CWSNC continued to expand its AMR meter footprint in its mountain systems. He commented that approximately 2,500 AMR meters were installed in the Connestee Falls and Fairfield Mountain Subdivisions. Witness Mendenhall testified that benefits of AMR meter technology to customers and the Company include: (1) customer satisfaction with data and billing accuracy; (2) improved customer service; (3) reduction in re-read/re-billing; (4) employee safety, especially during hazardous weather events; (5) replacement of inaccurate meters which can improve non-revenue water percentages; and (6) customer interaction with respect to personal consumption habits and trends. He noted that while AMR technology would be beneficial to CWSNC customers across the state, the mountain area systems, in particular, benefit due to the extreme weather events and related safety hazards that are common in this region. Witness Mendenhall testified that the Connestee Falls and Fairfield Mountain AMR meter installation projects were completed by July 31, 2019, at a total cost of 880,209.

At the time this rate case and CWSNC's deferral accounting Petition were filed Company witness DeStefano estimated that implementing these four projects would create a material drag on the consolidated Company's earned rate of return on common equity of 193 basis points. Witness DeStefano testified that the Company included in its rate case filing both a calculation of the deferral balances and proposed amortizations of the deferrals, as well as a pro forma adjustment relating to O&M savings that will result from the implementation of the AMR meter projects [1]. Public Staff witness Darden confirmed in her testimony that the Company included in this rate case proceeding a pro forma adjustment of $21,000 to remove the meter reading expense for the Fairfield Mountain and Connestee Falls water systems because AMR meters do not require an operator to read each meter individually.

[1] See NCUC Form W-1, Item 10, Schedules 26 and 34, filed June 28, 2019.

According to Public Staff witness Henry, all of the foregoing projects were completed and in service as of the date of the expert witness hearing as verified by Public Staff witness Casselberry, and final invoices were reviewed by the Public Staff. Tr. vol. 8, 172.

In its Sub 365 comments, the Public Staff recommended that the requested deferral accounting treatment with respect to the cost of the WWTPs at Nags Head and Connestee Falls be granted and that the requested deferral accounting treatment with respect to the AMR meters installed in Fairfield Mountain and Connestee Falls be denied in its entirety.

The Public Staff commented that in its Order Approving Deferral Accounting with Conditions in Docket No. E-7, Sub 874, the Commission stated:

> [T]he Commission has historically treated deferral accounting as a tool to be allowed only as an exception to the general rule, and its use has been allowed sparingly. That is due, in part, to the fact that deferral accounting, typically, provides for the future recovery of costs for utility services provided to ratepayers in the past; and . . . the longer the deferral period, the greater the likelihood that the ratepayers who are ultimately required to pay rates including the deferred charges, which are related to resources consumed by the utility in providing services in earlier periods, may not be the same ratepayers who received the services. The Commission has also been reluctant to allow deferral accounting because it, typically, equates to single-issue ratemaking for the period of deferral, contrary to the well-established, general ratemaking principle that all items of revenue and costs germane to the ratemaking and cost-recoveryprocess should be examined in their totality in determining the appropriateness of the utility's existing rates and charges.

Order Approving Deferral Accounting with Conditions, *Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Certain Environmental Compliance Costs and the Incremental Costs Incurred From the Purchase of a Portion of Saluda River's Ownership in the Catawba Nuclear Station*, No. E-7, Sub 874, at 24 (N.C.U.C. Mar. 31, 2009) (DEC Sub 874 Order).

In addition the Public Staff noted that in its Order Approving in Part and Denying in Part Request for Deferral Accounting in Docket No. E-7, Sub 1029, the Commission stated; "In determining whether to allow deferral requests, the Commission has consistently and appropriately based its decision on whether, absent deferral, the costs in question would have a material impact on the company's financial condition, and in particular, the company's achieved level of earnings." Order Approving in Part and Denying in Part Request for Deferral Accounting, *Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Certain Capital and Operating Costs Incurred for the Advanced Clean Coal Cliffside Unit 6 Steam Generating Plant, the Dan River Natural Gas Combined Cycle Generating Plant, and the Capacity-Related Modifications at the McGuire Nuclear Generating Plant*, No. E-7, Sub 1029, at 12-13 (N.C.U.C. Apr. 3, 2013).

Thus, the Public Staff maintained that the Commission's receptivity to deferral requests is not unlimited or without regard for traditional ratemaking principles. Rather, the Public Staff stated that the Commission requires a clear and convincing showing that the costs in question were of an unusual or extraordinary nature and that, absent deferral, the costs for which deferral was requested would have a material impact on the Company's financial condition.

In determining whether to grant a deferral request the Public Staff noted that the Commission analyzes the impact the costs would have on currently achieved earnings of the utility. The Public Staff stated that the appropriate test and criteria are as follows:

> The impact on earnings, typically, has been measured and assessed in terms of ROE, considered in conjunction with (1) the return on equity (ROE) realized and (2) the company's currently authorized ROE. Also . . . current economic conditions; the Company's need for new investment capital; and the impact that the Commission decision will have on future availability and cost of such capital are also relevant to the appropriate resolution of matters of this nature. Additionally, whether the company has requested or is contemplating requesting a general rate increase and the timing, or proposed timing, of the filing of such a request is also pertinent.

DEC Sub 874 Order at 26.

The Public Staff stated in its Sub 365 comments that it had evaluated the deferrals requested in CWSNC's petition against the above criteria. Based on these criteria and other Commission decisions, the Public Staff supported deferral accounting treatment for the costs related to the WWTP projects at Nags Head and Connestee Falls. The Public Staff based its recommendation on the fact that (1) costs for the WWTPs were related to major construction projects that, at the time the Sub 365 comments were filed, were not yet in service but expected to be completed and in operation prior to the date of the expert witness hearing in this general rate case; (2) the deferral accounting request was made contemporaneously with the filing of the rate case application; and (3) the deferral period would not be so long as to cause undue concern that the ratepayers who pay rates including the deferred WWTP costs during the deferral period may not be the same ratepayers who receive service from the WWTPs. Sub 365 Comments at 6–7. Additionally, the Public Staff stated that "the impact of the costs, if not deferred, on the Company's rate of return on common equity of 9.75% approved in the Sub 360 Rate Case, will be significant. Without deferral, the Company's earnings can be expected to decline due to the WWTPs becoming plant in service." *Id.* at 7. Thus, the Public Staff contended that the WWTPs at Nags Head and Connestee Falls presented the kind of circumstances in terms of nature, impact, and timing for which deferral accounting treatment is appropriate.

Moreover, as evidenced by the Stipulation filed on November 27, 2019, the Company and the Public Staff are in agreement that the Company's request to defer incremental post-in-service depreciation expense and financing costs of the WWTPs at Nags Head and Connestee Falls is appropriate and have agreed that the Company should be authorized to defer its costs of $1,098,778 related to its WWTPs, and these costs should be amortized over five years, for an annual amount to be included in rates of $219,756.

With respect to the Public Staff's recommendation that the Commission deny deferral accounting treatment for the AMR meters installed in Fairfield Mountain and Connestee Falls, the Public Staff stated it used the same criteria for evaluating the Company's request for deferral of the WWTPs and the AMR meter costs and concluded that CWSNC's request for deferral of the AMR meter costs should be denied. Witness Henry contended that CWSNC failed to make a clear, complete, and convincing showing, in view of the entire record, that the costs of the AMR meters are of an unusual or extraordinary nature and, absent deferral, will have a material impact on the Company's financial condition. In his direct testimony, witness Henry referred the Commission to the Public Staff's initial comments filed on September 20, 2019 in Sub 365.

In its Sub 365 initial comments, the Public Staff contended that meter replacement of any kind (AMR, AMI, traditional, etc.) is not an extraordinary or unusual project but should be considered routine and as part of a properly planned and managed meter replacement program. The Public Staff stated that water meters have an industry recognized 10- to 20-year useful life before degradation of functionality and accuracy necessitate replacement. Additionally, the Public Staff stated that CWSNC has water meters in service that range in age and condition, and that it is not unusual for a water and sewer utility to undertake, during one time period, to replace a large number of aged meters in an entire subdivision or service area because doing so promotes efficiency of time and cost. Due to the nature of meter replacement being an expected and usual occurrence, the Public Staff stated that the only different or unusual aspect of the Company's replacement project is the increased cost of the new AMR meters over the cost of analog meters. The Public Staff further noted that although the Company stated that the upgraded technology will benefit the Company and the customers, the Company's decision to upgrade does not change the nature of the typical and expected meter replacement project. The Public Staff maintained that the increased cost of AMR meters and the number of meters replaced is the result of management decisions within CWSNC's control and a failure of the Company to implement a systematic and measured meter replacement program.

On cross-examination witness Henry confirmed that the Public Staff's accounting investigation did not raise any prudency issues with respect to the costs incurred by the Company to complete the AMR meter installation projects, that the Public Staff did not recommend any significant disallowance of any part of these costs for ratemaking purposes, that this is the third rate case in which the Company has included costs for AMR meters for its mountain systems, and that the Public Staff did not raise any objections or questions about the prudency of the installations or of the costs of prior AMR meter installations in the previous two cases. He also agreed that deferred accounting is one way to address the issue of regulatory lag faced by a utility.

Further, witness Henry agreed that the $22 million in additional investment made by the Company since its last rate case is a significant amount of investment of capital for a company the size of CWSNC and that those investments result in regulatory lag, depending on the timing of the investments and when those investments are incorporated for recovery in rates. He also updated his estimate of earnings erosion that would occur if CWSNC's request for deferral of costs related to AMR meter installation projects is denied based upon the Company's updated project costs. He testified that the Company's rate of return on common equity for the Uniform Water Rate Division would be negatively impacted by 24 basis points if the Commission denies deferral accounting treatment for the AMR meter installation projects. Witness Henry testified that he added the AMR meter installation projects to the rate case model that was used to calculate the gross revenue and overall rate of return allowed by the Commission in the Sub 360 Rate Order. Witness Henry stated that by including the AMR meter installation projects in that model for the Uniform Water Rate

Division the rate of return on common equity granted in the Sub 360 case was decreased from 9.75% to 9.51%, a decrease of 24 basis points. Tr. vol. 8, 180. Witness Henry maintained that it was appropriate to evaluate the rate of return on common equity impact at the Rate Division level because CWSNC has four separate rate divisions: Uniform Water, Uniform Sewer, BF/FH/TC Water, and BF/FH Sewer. He stated that each of these rate divisions has a separate rate base, revenues, expenses, and rate of return. Tr. vol. 8, 217–18. Witness Henry further stated that rates have not been established on a total company basis in this rate case nor in prior rate cases filed by CWSNC.

Witness Henry agreed that, in addition to the basis point impact on rate of return on common equity, the Commission has considered the actual earned rate of return on common equity of the utility requesting deferral accounting when addressing whether non-deferral of project costs would have a material negative impact on a company's financial condition. Further, he agreed that the Commission considers deferral requests on a case-by-case basis.

On cross-examination Public Staff witness Junis expanded upon witness Henry's conclusion that the Company's AMR meter installation projects did not meet the Commission's criteria for deferral accounting. He maintained that the projects were not unusual or extraordinary because they were the result of a business choice by the Company to install AMR meter technology. Tr. vol. 8, 191. He stated that the Company could have installed traditional meters rather than AMR meters. Witness Junis testified that meter replacement should be a part of normal business. Further, he stated that AMR meters are not providing service to customers or improving service to customers and thus they are not integral to providing service. Tr. vol. 8, 198. Witness Junis distinguished AMR meters from new electricity generation investments or wastewater treatment plant investments, stating that the latter are integral to providing quality service. *Id.*

Witness Junis discounted CWSNC's claim that the Company is underearning because the underearning took place primarily under previously set rates, before the current rates were established by the last rate order in Sub 360. Tr. vol. 8, 205. Witness Junis contended that for this reason, the test period would not be the "proper window to look at when considering are they under-earning or over-earning" for purposes of the Commission's test to determine whether deferral accounting is appropriate. Tr. vol. 8, 205–06. He testified that the utility decides when it files rate cases; the Company's management decides how much consequence of regulatory lag it can accept and financially tolerate between rate cases. Tr. vol. 8, 195.

On cross-examination, witness Junis acknowledged that the Public Staff's position is that AMR meter installation projects are not eligible for cost recovery in WSIC proceedings because the WSIC statute calls for "in-kind" replacements. Witness Junis testified that the Public Staff does not consider AMR meters as in-kind with regard to differing kinds of meters. Tr. vol. 8, 195–96. He further testified that both deferral accounting and the WSIC and SSIC statute minimize regulatory lag for cost-recovery purposes. He agreed that the fact that the AMR meter installation projects do not qualify for WSIC treatment is worth considering in the context of a deferral accounting request. However, he testified that it should not be a major factor in the determination and ultimately this fact did not change the Public Staff's position that deferral should be denied.

Witness DeStefano presented rebuttal testimony explaining the appropriateness of deferral accounting treatment for the Company's two AMR meter installation projects. First, he testified that major technological upgrades such as the Company's AMR meter projects are the type of projects for which deferral accounting is appropriate. He noted that the Company's AMR meter program involves the mass replacement and technological upgrade of aged analog meters in certain targeted geographical areas, as opposed to the typical individual meter replacements that occur due to aging or damaged individual meters. He emphasized that this AMR meter program differs dramatically from individual and routine meter replacements in scope, scale, purpose, and financial impact. Witness DeStefano generally testified that the large-scale meter replacement at issue was undertaken to improve service through efficiencies, safety, and advanced technology, and that the project benefitted customers by saving some costs associated with manual meter reading and reducing system water loss. He further testified that the Company would face significant adverse impact if either the four projects subject to the petition to defer or the AMR meter projects alone were not afforded deferral accounting treatment. He explained that the Company's current overall rate of return of 7.75% authorized by the Commission in Sub 360 was not being achieved and that the Company's consolidated actual earned overall return during the test year for the instant rate case was only 3.69%.

Witness DeStefano maintained that the Public Staff's proposed rejection of deferral accounting for the two AMR meter installation projects, as well as the inability of the Company to recover the costs of depreciation and a return on the full investment of AMR meters in a WSIC filing, has the effect of significantly penalizing the Company through denial of timely cost recovery for investments in modernizing its water system operations. Witness DeStefano contended that if the Company's cost recovery for AMR meters is limited solely to a final decision in a general rate case, with no interim deferral accounting, the Company's earnings will be materially affected to its detriment. He reported that other state regulatory commissions have authorized deferral accounting in connection with meter replacement projects although he did not state whether such deferrals related specifically to the deferral of post-in-service depreciation expense and carrying costs from the AMR meter replacement projects in-service dates until the projects are included for recovery in base rates as requested by CWSNC in its petition.

Witness DeStefano urged the Commission to consider the collective financial impact of the four projects, noting that the Commission has previously considered projects on a collective basis when making deferral accounting determinations. Witness DeStefano commented that in the DEC Sub 874 Order, the Commission authorized a utility to use deferred accounting combining costs for two projects, wherein it allowed deferral accounting for both an environmental compliance cost project and the purchase of a portion of a nuclear facility on the grounds that the authorized rate of return on common equity would be eroded due to the rate of return on common equity impact of costs of 114 basis points — 67 for the environmental costs and 47 points for the facility purchase. In its reply comments CWSNC maintained that when considering the four major new projects together, the financial impact to the total Company earnings would be materially adverse, having a rate of return on common equity impact of 187 total basis points.[1]

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[1] See updated Schedule 1 attached to CWSNC's reply comments filed on October 21, 2019 in Sub 365. In its Petition filed on June 28, 2019 CWSNC calculated a rate of return on common equity impactof 193 basis points for the four major new projects on a total Company basis.

Finally, witness DeStefano argued that even if the Commission were to evaluate the WWTP and the AMR meter projects separately, the rate of return on common equity impact of the AMR meter costs would still have an adverse material effect on the Company's earnings, and, thus, deferral accounting for the meter projects is merited – particularly given the Company's current underearning position. Witness DeStefano stated that given the Company's size and current underearning status, a 20-basis point AMR meter impact for the Uniform Water Rate Division[1] is unquestionably material to the Company.

During cross-examination Company witness DeStefano was questioned about Public Staff DeStefano Cross-examination Exhibit 1, which contained witness DeStefano's responses to Public Staff Data Request No. 81. Witness DeStefano confirmed that the Company had sought and received rate recovery in its Docket No. W-354, Sub 344 (Sub 344) rate case for AMR meter installation projects that occurred in 2015 in seven systems. The evidence presented confirmed that the Company's Sub 344 rate increase included the costs of 1,157 AMR meters for a total cost of over $1.2 million, and in the Company's Sub 356 rate case, CWSNC received rate recovery for AMR meter installation projects in three systems, including 2,440 meters, for a total cost of over $1.8 million. Tr. vol. 9, 158–59. Witness DeStefano also confirmed that the Company planned to complete eight similar projects over the next four years, including nearly 4,000 AMR meter replacements. Witness DeStefano further confirmed that the Company has already completed ten AMR meter projects, including 3,597 meters at a total capital cost of over $3 million, prior to the two projects presented in this case at a cost of less than $900,000.

Upon further questioning by the Public Staff witness DeStefano explained why CWSNC requested deferral accounting for two AMR meter projects at issue, but not for its previous AMR meter projects. He explained that the AMR meter projects currently being made are part of a much larger overall capital investment by the Company. He noted that in prior years overall capital investments made by the Company were in the $10 million per year range, versus $20 million invested in the current year. As a result, according to witness DeStefano, the deferral accounting request is due in part to the additional regulatory lag impact being experienced by the Company beyond the impact of the AMR meter projects alone. Additionally, he testified that the two AMR meter installation projects for which deferral accounting treatment is currently requested are larger than every meter system previously installed.[2] He explained that installing AMR meters in these two systems in this one year and trying to gain the efficiencies of completing the projects this year increases the financial implications to the Company and the significance of the projects to the Company. In summary witness DeStefano testified that with the magnitude of the capital spending CWSNC anticipates over the next few years to address aging system needs, the Company is looking for ways to mitigate the effect of regulatory lag on earned returns.

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[1] During the expert witness hearing, witness DeStefano agreed with Public Staff witness Henry's calculation of a 24-basis point negative impact on CWSNC's earned rate of return on common equity for the Uniform Water Rate Division if deferral accounting treatment for the AMR meter projects is not approvedby the Commission.

[2] Company witness Mendenhall added that the 2,500 AMR meters at issue represent about 40% of the total AMR meters installed and about 8% of CWSNC's total meters in service in the State.

WATER AND SEWER – MISCELLANEOUS

Discussion and Conclusions

In its Sub 365 Petition CWSNC has requested that the Commission enter an accounting order allowing the Company to defer certain post-in-service costs that were incurred in connection with two WWTP projects and two AMR meter installation projects. The related costs for which the Company seeks deferral include the incremental post-in-service depreciation expense and cost of capital (financing costs) from their respective in-service dates until the projects are included for recovery in base rates in this case. According to the evidence of record, the amounts of such costs with respect to the WWTP projects and the AMR meter installation projects are $1,098,778 and $64,736, respectively. The Company contends that the financial impact of these costs is material and would, absent deferral, equate to a significant basis point reduction in the Company's rate of return on common equity. Evidence submitted by the Public Staff confirmed that such projects when included in plant in service would individually equate to a 434-basis point rate of return on common equity reduction for the WWTPs and a 24-basis point rate of return on common equity reduction for the AMR meter installation projects for the Uniform Sewer Rate Division and the Uniform Water Rate Division, respectively. No party has suggested that either the WWTP projects or the AMR meter installation projects are imprudent in any way. Moreover, the Company and the Public Staff are in agreement regarding the amount of costs included in plant in service in this proceeding for the WWTP projects and the AMR meter installation projects.

Under the Company's proposal the costs in question would not be charged against revenues realized during the accounting period in which the costs were actually incurred. Rather, such costs would be deferred and accumulated in a regulatory asset account. As a result, the deferred costs, in effect, would be specifically reserved for recovery prospectively. The period over which the costs would be accumulated in a regulatory asset account would begin when the assets were placed in service and end on the date the Company is authorized to begin charging rates reflecting the inclusion of the WWTPs and the AMR meter installation projects in CWSNC's water and wastewater cost of service. Consequently, approval of CWSNC's deferral and cost recovery proposal would ultimately result in a level of rates, to be charged prospectively, that would specifically include an allowance providing for the recovery of the present deferred costs. On the other hand, if the request for deferral is denied, the Company would then be required to recognize the costs for which it seeks deferral as items of expense in the period in which they were incurred. In this instance, the Company would then be required to recognize those costs during a period in which it contends it is already significantly under-recovering its Commission-authorized return.

Deferral accounting should only be used sparingly as an exception to the general rule that all items of revenue and costs germane to the ratemaking and cost-recovery process should be examined in their totality in determining the appropriateness of the utility's existing rates and charges. DEC Sub 874 Order at 24. Deferral is not favored, in part, because deferral accounting typically provides for the future recovery of costs for utility services provided to ratepayers in the past. The Commission has also been reluctant to allow deferral accounting because it typically equates to single-issue ratemaking for the period of deferral. *Id.* The Commission acknowledges that considering an increase in one or a few expense items in isolation, without considering reductions in other costs, brings with it the increased risk of over-recovery. However, the Commission gives significant weight in this instance that the consolidation of the Sub 365 petition for deferral accounting with the Sub 364 general rate case means that the concern regarding single-issue ratemaking and the related risk of such over-recovery should be reduced and of lesser concern because all revenues and expenses will have been examined close in time to any possible deferral.

While deferral accounting must not be used routinely or frequently, the Commission has found that an exception can be made when the costs at issue "were reasonably and prudently incurred, unusual or extraordinary in nature, and of a magnitude that would result in a material impact on the Company's financial position (level of earnings)." Order Denying Request to Implement Rate Rider and Schedule Hearing to Consider Request for Creation of Regulatory Asset Account, *Application of Duke Energy Carolinas, LLC, for Approval of Rate Rider to Allow Prompt Recovery of Costs Related to Purchases of Capacity Due to Drought Conditions,* No. E-7, Sub 849, at 19 (N.C.U.C. June 2, 2008) The Commission has, over the years, on infrequent but appropriate occasions, approved requests proposing the use of deferral accounting. Such requests, by necessity, must be examined and resolved on a case-by-case fact-specific basis and will be approved only where the Commission is persuaded by clear and convincing evidence that the costs in question are unusual or extraordinary in nature and that, absent deferral, would have a material impact on the utility's financial condition. *Id. See also,* Order Approving Deferral Accounting with Conditions, *Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Certain Environmental Compliance Costs and the Incremental Costs Incurred From the Purchase of a Portion of Saluda River's Ownership in the Catawba Nuclear Station,* No. E-7, Sub 874 (N.C.U.C. Mar. 31, 2009); Order Approving Deferral Accounting, *Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Certain Capital and Operating Costs Incurred for the Buck Natural Gas Combined Cycle Generating Plant and the Bridgewater Hydro Generating Plant,* No. E-7, Sub 999 (N.C.U.C. June 20, 2012) (DEC Sub 999 Order); Order Approving Deferral and Amortization, *Request by Duke Power, A Division of Duke Energy Corporation for Approval of Accounting Treatment,* No. E-7, Sub 776 (Dec. 28, 2004).

In determining whether the costs sought to be deferred or the events or circumstances leading to the costs are of such an unusual or extraordinary nature as to justify an exception to the rule against allowing deferral accounting treatment, the Commission historically examines the record for clear and convincing evidence that the costs in question represent major non-routine, infrequent, non-regularly occurring investments of considerable complexity and significance or were beyond the control of the utility such as storm costs or new operating requirements/standards imposed by newly-enacted legislation or other governmental action. *See,* Order Approving Deferral Accounting, *Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Certain Environmental Compliance Costs at Unit 5 of the Cliffside Steam Station,* No. E-7, Sub 966 at 10 (N.C.U.C. June 27, 2011); *Order Ruling on Petition,* Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer 2009 and 2010 Non-Fuel Energy Costs Excluded from Cost Recovery in the Commission's August 6, 2010 Order in Docket No. E-7, Sub 934, No. E-7, Sub 967, at 14-15 (N.C.U.C. June 14, 2011); *Order Approving in Part and Denying in Part Request for Deferral Accounting,* Petition of Duke Energy Carolinas, LLC for an Accounting Order to Defer Certain Capital and Operating Costs Incurred for the Advanced Clean Coal Cliffside Unit 6 Steam Generating Plant, the Dan River Natural Gas Combined Cycle Generating Plant, and the Capacity-Related Modifications at the McGuire Nuclear Generating Plant, No. E-7, Sub 1029, at 13, 15 (N.C.U.C. April 3, 2013); Order Adopting and Amending Rules, *Rulemaking Proceeding to Implement G.S. 62-110.8,* No, E-100, Sub 150 at 22 (November 16, 2017).

In certain circumstances the Commission may find that the magnitude or level of the costs requested for deferral make the costs major, non-routine, or extraordinary. In some cases, the Commission has looked to determine whether costs were unanticipated, unplanned, beyond the control of the utility, and of an infrequent, non-recurring nature; that is, whether the costs and the circumstances of the costs are sufficiently unusual or extraordinary to warrant deferral accounting treatment – a tool not to be used routinely but sparingly as discussed above. Order Approving Amended Schedule NS and Denying Deferral Accounting, *Application by Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, for Approval of Amended Schedule NS,* No. E-22, Sub 517, at 11– 12 (N.C.U.C. Mar. 29, 2016). A finding that the magnitude of the costs supports a determination that they are unusual or extraordinary may not, in some circumstances also support a finding that these costs, if not deferred, will have a material adverse impact on the company's financial condition to warrant deferral accounting treatment. In determining whether deferral or non-deferral will have a material impact on the company's financial condition while the Commission may consider other matters, it often examines whether and to what extent the costs incurred will have a significant impact on the level of company earnings and the company's ability to achieve its currently authorized rate of return on common equity. DEP Sub 874 Order at 25–26. In determining materiality, while the Commission may consider other matters, it often examines whether and to what extent the costs incurred will have a significant impact on the level of company earnings and the company's ability to achieve its currently authorized rate of return on common equity. *Id.*

With regard to the WWTP projects, the Commission is persuaded that the costs are of an unusual, extraordinary nature. Both the Company and the Public Staff also agree that the costs associated with the WWTP projects are unusual or extraordinary in nature, as the Commission has used those terms in previous deferral accounting orders and as those terms are commonly understood. The Commission observes as stated in a previous deferral accounting case, *"[t]he costs in question are unusual or extraordinary in the sense that they are associated with the incorporation of the costs of two [WWTP] facilities – representing major investments – into the Company's rate structure; which is not a simple, regularly occurring, inconsequential event, but rather, is a major non-routine matter of considerable complexity and major significance."* DEC Sub 999 Order, at 18. In the present proceeding, the evidence demonstrates that the WWTP projects were not an everyday, regular occurrence but were in fact non-routine, complex, and of major significance and that the associated costs are similarly unusual or extraordinary. The WWTP projects involved the installation of new treatment facilities that were integral to providing wastewater utility service and that were necessitated by conditions causing the old facilities to present unacceptable risks of failure and inability to comply with environmental requirements exposing the company to the further high risk of severe penalties and imposition of a consent decree. Such circumstances and replacement of such major facilities that are at risk of both functional and environmental compliance failure do not occur on a frequent basis.

The Commission is likewise persuaded that absent deferral, the costs will have a material impact on the Company's financial condition. The evidence demonstrates that the Company is not meeting its currently authorized rate of return on common equity and that even if the Sub 360 rate increase had been in effect for a full year, the rate of return on common equity impact of the costs of the WWTP projects would have an adverse impact on the Company's financial condition. The Commission gives significant weight to the undisputed testimony of witness DeStefano that

CWSNC's consolidated actual earned rate of return on common equity during the test year for this rate case (the 12-month period ended March 31, 2019) was 1.63%. The Commission further finds credible the evidence that the rate increase in the last rate case was approximately $1.1 million, which would not make up the difference from an actual rate of return on common equity of 1.63% to 9.75%, CWSNC's authorized rate of return on common equity granted in the Sub 360 Rate Order. Further, the evidence shows that the WWTP investments of approximately $14 million would result in a 434-basis point rate of return on common equity reduction for the Uniform Sewer Rate Division. The Commission concludes that if the requested deferral for the WWTP projects is not allowed, it would appear that the Company's already low rate of return on common equity would be further eroded and that the Company would not have a reasonable opportunity to earn its authorized rate of return on common equity.

Furthermore, given the Company's depressed level of current earnings and its expected near-term significant financing needs, the Commission determines that deferral of the WWTP costs as requested by CWSNC will have a favorable impact on CWSNC's earnings and financial standing in general. As such, the deferral will enhance the Company's ability to access and obtain capital on more favorable terms, as it will help assure investor confidence in the Company. Such results will ultimately accrue to the benefit of CWSNC's customers.

Moreover, the Company and the Public Staff have agreed by Stipulation that the Company should be allowed to defer the incremental post-in-service depreciation expense and financing costs of the WWTPs at Nags Head and Connestee Falls as requested by CWSNC because they are both unusual in nature and material to the Company's financial condition. In light of the Commission's having accepted the Stipulation in its entirety and in light of the foregoing independent determination based on the evidence of record that the costs at issue are both unusual, non-routine, and material to the Company's financial well-being, the Commission finds the Company's request to defer post-in-service depreciation and financing costs for the WWTP projects is just and reasonable and should be approved.

Thus, as provided in the Stipulation, Revised Settlement Exhibits I and II, and the testimony of witness Henry (as revised on the stand) and in Henry Late-Filed Exhibits 2, 3, and 4, the Commission finds and concludes that the Company should be authorized to defer its WWTP costs of $1,098,778 related to its WWTPs (consisting of incremental post-in-service depreciation expense and financing costs from their respective in-service dates until the WWTPs are included for recovery in base rates in this case), and these costs should be amortized over five years, for an annual amount to be included in rates of $219,756.

Unlike the deferral accounting request related to the WWTP projects, the Public Staff opposed deferral accounting treatment of the costs associated with the two AMR meter installation projects. The Commission agrees with the Public Staff. The Commission finds that the Company provided insufficient evidence that the projects and their associated costs are unusual or extraordinary such as to warrant deferral accounting. While a mass replacement of meters in an entire subdivision is not an everyday occurrence for CWSNC, the Commission is not convinced that such an event is sufficiently unusual or extraordinary to justify special deferral accounting treatment. The need to replace meters on a planned schedule is an anticipated need of the business and the timing and manner of implementation of such replacement, at least as was the case in this proceeding, is entirely within the control of the Company. Further, the Company did not establish by clear and convincing evidence that the meter installation costs sought to be deferred support a finding that the projects or said costs are unusual or extraordinary. On cross-examination witness DeStefano confirmed that the Company had sought and received rate recovery in its Docket No. W-354, Sub 344 (Sub 344) rate case for AMR meter installation projects that occurred in 2015 in seven systems. The evidence presented confirmed that the Company's Sub 344 rate increase included the costs of 1,157 AMR meters, for a total cost of over $1.2 million, and in the Company's Sub 356 rate case, CWSNC received rate recovery for AMR meter installation projects in three systems, including 2,440 meters, for a total cost of over $1.8 million. Considering that since 2015 CWSNC has completed ten AMR meter projects, including 3,597 meters at a total capital cost of over $3 million, the Commission determines that the two AMR meter installation projects for Fairfield Mountain and Connestee Falls in the amount of $880,209 are not major non-routine, infrequent, non-regularly occurring investments of considerable complexity and significance for CWSNC. Rather, the Commission finds that the two AMR meter installation projects are routine and regularly occurring and are not unusual or extraordinary in nature.

Having determined that the Company failed to establish that its AMR meter installation project and the related costs were unusual or extraordinary such as to justify allowing exceptional deferral accounting treatment, the Commission does not reach the issue of whether the AMR costs sought to be deferred have a material adverse impact on the Company's financial condition or stability. The determination that this project and its related costs are not unusual or extraordinary is dispositive. Therefore, the Company's petition to defer these costs is not just and reasonable and is denied. However, the Commission emphasizes that decisions such as this one are made on a case-by-case basis, and this decision should not be construed to suggest that costs relating to a meter project can never be allowed deferral accounting treatment. The Commission acknowledges that every request for deferral accounting is shaped by its own unique factual circumstances, and whether an event and its related costs are sufficiently unusual or extraordinary in nature to merit an exception to the general rule against deferral accounting treatment is a determination for the Commission that will be based on the specific facts of each such request. The Commission notes that the Company's request for deferral accounting treatment for costs related to the WWTPs and the two AMR installation projects is determined within the context of this general rate case where the Commission is setting just and reasonable rates on a going-forward basis. The Commission's decision either granting or denying deferral accounting treatment in the present case is made from the standpoint of fairness and equity to both consumers and the Company.

Although deferral accounting is to be employed sparingly, the Commission finds that CWSNC has another option available to use to recover costs associated with future AMR meter deployments. Recognizing the challenges confronting North Carolina's water and wastewater industries in needing to make high cost capital investments to install and replace aging infrastructure, the General Assembly has provided the Commission with a tool specific to water and sewer utilities to alleviate the effects of regulatory lag. Section 62-133.12 authorizes the Commission to approve a rate adjustment mechanism in a general rate case to allow a water or sewer utility to recover the incremental depreciation expense and capital costs associated with reasonable and prudently incurred investment in eligible system improvement projects through the collection from customers of a water or sewer system improvement charge (WSIC or SSIC). The Commission approved such a mechanism for CWSNC in Docket No. W-354, Sub 336 pursuant to an order issued on March 10, 2014. Eligible water system improvements to be recovered by use of WSIC include "distribution system mains, valves, utility service lines (including meter boxes and appurtenances), meters, and hydrants installed as in-kind replacements." N.C.G.S. § 62-133.12(c)(1).

Notwithstanding this tool created to help utilities better manage regulatory lag, both Public Staff witness Junis and CWSNC witness DeStefano testified that, other than deferral, there is currently no rate mechanism such as the WSIC or SSIC mechanism available to the Company to mitigate the regulatory lag and resultant adverse earnings impacts associated with the mass replacement of traditional meters with AMR meters because, according to them, the WSIC and SSIC statute only allows recovery for "in-kind" replacements. Tr. vol. 8, 61-62, 195–96. As is clear from the testimony and CWSNC's stated position in its proposed order, the Company has accepted the Public Staff's interpretation that replacing an analog meter with an AMR meter is not an "in-kind" replacement. Tr. vol. 8, 61–62. The Commission does not agree with this interpretation. Although this question has not previously been brought to the Commission for decision, the Commission holds that the exchange of one type of meter reading device for another type of meter reading device is an "in-kind" replacement as that term is used in N.C.G.S. § 62-133.12(c)(1). The Public Staff appears to read the words "in kind" to mean "like kind and quality' or perhaps "like grade and quality" but this amounts to an impermissible rewriting of the statute. Such an interpretation would defeat the purpose of providing water and sewer utilities with the opportunity to seek recovery under an approved rate adjustment mechanism. Black's Law Dictionary defines "in kind" as "of the same species or category" or "in the same kind, class or genus." Black's Law Dictionary (5th ed. 1979) Bouvier Law Dictionary defines "in kind" as "[p]roperty in its physical form, or property similar to property in issue. In kind refers to specific property, either the property itself in issue or similar property of the same form, quality, and value as the property in issue." Bouvier Law Dictionary (Desk ed. 2020) The Commission concludes an "in-kind" replacement can be an identical replacement or one that is a reasonable alternative to serve the same purpose. If the General Assembly's use of "in kind" limited replacement to the exact identical equipment, upgrade replacements could never be eligible improvements for WSIC or SSIC recovery. A utility seeking to replace a non-functioning obsolete item of equipment with the then-current industry standard equipment would be stymied, and the Commission is not able to conclude that such an outcome was intended by a statute that was meant to facilitate repair and replacement of basic items of utility plant and equipment. Accordingly, with regard to AMR meter installation projects planned for the future, CWSNC and the Public Staff should work together pursuant to Commission Rule R7-39 to mitigate regulatory lag using WSIC recovery. However, the Commission's decision herein does not in any way relieve the Company of its burden to prove its investments are reasonable and prudently incurred as required by N.C.G.S. § 62-133.12 and Commission Rule R7-39(a). Moreover, in its Order Adopting Rules to Implement G.S. § 62-133.12, *Petition for Rulemaking to Implement G.S.62-133.12, North Carolina Session Law 2013-106(House Bill 710)*, No. W-100, Sub 54 (N.C.U.C. June 6, 2014), the Commission concluded that

> any rate adjustments authorized under the WSIC and SSIC mechanisms outside of a general rate case will be allowed to become effective, but not unconditionally approved. In other words, the adjustments will be provisional, will not be deemed *prima facie* just and reasonable, and, thus, may be rescinded retroactively in the

utility's subsequent general rate case, at which time the adjustment may be further examined for a determination of its justness and reasonableness.

Id. at 5.

The Commission also notes the Company's testimony and evidence regarding ongoing improvement projects and the need and plans for substantial capital investment in the near future. In consideration of this continuing and anticipated increase in capital spending to address aging infrastructure, the Commission recommends that CWSNC seek to make better use of the WSIC and SSIC mechanisms as a regulatory tool to mitigate the negative effects of regulatory lag for all statutorily allowed system improvement projects.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 42

Depreciation and Amortization Expense

The evidence supporting this finding of fact is found in the verified Application and the accompanying NCUC Form W-1, the testimony of Public Staff witnesses Feasel and 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 per Application	Difference	Amount per Public Staff
Depreciation expense	$6,399,241	$181,470	$6,580,711
Amortization exp. - CIAC	(1,485,664)	8,710	(1,476,955)
Amortization exp. - PAA	(85,341)	8,718	(76,623)
Amortization of ITC	(579)	0	(579)
Total	$4,827,656	$198,898	$5,026,554

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 testimony and reflected in Henry Revised Exhibit I and Feasel Revised Exhibits I and II, 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.

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	$6,580,711
Amortization expense – CIAC	(1,476,955)
Amortization expense – PAA	(76,623)
Amortization of ITC	(579)
Total	$5,026,554

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 43

Franchise, Property, Payroll and Other Taxes

The evidence supporting this finding of fact is found in the verified Application and the accompanying NCUC Form W-1, and in the testimony of Public Staff witness Henry and 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	Difference	Amount per Public Staff
Franchise and other taxes	($789)	$135	($655)
Property taxes	268,734	0	268,734
Payroll taxes	596,100	(68,672)	527,428
Total	$864,045	$(68,537)	$795,507

With the Stipulation and revisions made by the Public Staff in its Feasel Revised Exhibits I and II and Henry Revised 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.

Based on the foregoing, the Commission concludes that the appropriate level of franchise, property, payroll, and other taxes for use in this proceeding is as follows:

Item	Amount
Franchise and other taxes	($655)
Property tax	268,734
Payroll taxes	527,428
Total	$795,507

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 44-47

Regulatory Fee and Income Taxes

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 table 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 per Application	Difference	Amount per Public Staff
Regulatory fee	$56,361	($12,202)	$44,159
State income taxes	218,982	(143,508)	75,474
Federal income taxes	1,793,462	(1,175,329)	618,133
Deferred income taxes	0	(69,128)	(69,128)
Total	$2,068,805	($1,400,167)	$668,638

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 $44,159.

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 $75,474 based on the current state corporate income tax rate of 2.50%.

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 $618,133 based on the current federal corporate income tax rate of 21.00%.

Deferred Income Taxes

With the Stipulation and revisions made by the Public Staff in its Feasel Revised Exhibits I and II, and Henry Revised 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 $69,128 to reflect the annual amortization of protected and unprotected federal EDIT.

Based on the foregoing, the Commission concludes that the appropriate level of regulatory fee and income taxes for use in this proceeding is as follows:

Item	Amount
Regulatory fee	$44,159
State income taxes	75,474
Federal income taxes	618,133
Deferred income taxes	(69,128)
Total	$668,638

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 48-50

The Federal Tax Cuts and Jobs Act

The evidence supporting these findings of fact is found in the verified Application and the accompanying NCUC Form W-1, the testimony of Company witness DeStefano,the testimony of Public Staff witness Boswell, and the Stipulation and Settlement Exhibit 1.

In its Application and in the direct testimony of CWSNC witness DeStefano, the Company proposes to include adjustments to the reserve balances for both federal protected EDIT and federal unprotected EDIT based upon the Company's final 2017 federal income tax return filed in late 2018. For federal protected EDIT the Company recommends that the Commission conclude that it is appropriate for CWSNC to continue to return the federal protected EDIT balance maintaining the amortization period approved by the Commission in the Sub 360 Order. In addition, in witness DeStefano's testimony, the Company recommends reducing the term of the federal unprotected EDIT rider approved in the Sub 360 Order (originally 48 months with 35 months now remaining) to a two-year (or 24-month) term as of the effective date of the current proceeding.

Public Staff witness Boswell stated in her direct testimony that certain adjustments to book balances and reserves related to EDIT were recorded to CWSNC's books, adjustments that were not reflected in the Company's most recent rate case. She noted that these adjustments affect the balance of both federal protected EDIT and federal unprotected EDIT. Witness Boswell further stated that the adjustments to the federal protected EDIT and federal unprotected EDIT balances are primarily because: (1) the Company took advantage of a late IRS notice stating that regulated utilities were allowed 100% bonus depreciation for those assets placed in service during the period of September 28, 2017, to December 31, 2017, without a binding contract in place before September 28, 2017, and (2) the Company adjusted amounts utilized in the prior rate case to the actual amounts on its final tax return for 2017. Witness Boswell recommended one adjustment to correct mismatched calculations. She proposed calculating both federal protected EDIT and federal unprotected EDIT amortizations with the adjustments effective as of April 1, 2020. Finally, the Public Staff does not oppose the Company's request to refund the remaining federal unprotected EDIT balance over 24 months instead of the remaining 35 months as originally ordered in Sub 360.

Settlement Exhibit I filed with the Stipulation in the current proceeding reflects the correction to the calculation of federal unprotected EDIT proposed by Public Staff witness Boswell, the reduction of the rider period for the federal unprotected EDIT from 35 months to 24 months, and includes the rate base impact of the flow back of federal protected EDIT in accordance with the RSGM, as approved in Sub 360, in the revenue requirement. In addition, the revenue requirement depicted on Settlement Exhibit I also includes the flow back of state EDIT in accordance with previous Commission orders in Sub 356 and Sub 360. No other party presented evidence on these matters.

Based on the foregoing, the Commission concludes that it is reasonable and appropriate for purposes of this proceeding to accept the Stipulation between CWSNC and the Public Staff on the tax issues. Therefore, the Commission concludes that CWSNC should continue to flow back the federal protected EDIT in accordance with the RSGM as ordered in Sub 360, and the Company shall refund its remaining federal unprotected EDIT balances over 24 months instead of the remaining 35 months as originally ordered by the Commission in Sub 360. Further, CWSNC should continue to flow back the state EDIT (which was originally over a three-year period) in accordance with the Commission's Sub 356 Order as confirmed in the Commission's Sub 360 Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 51-59

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

The evidence supporting these findings of fact and conclusions is contained in the verified Application and the accompanying NCUC Form W-1, the testimony and exhibits of the public witnesses, the direct and rebuttal testimony and exhibits of Company witness D'Ascendis, and the direct and supplemental testimony and exhibits of Public Staff witness Hinton.

Rate of Return on Equity

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

Summary of Record Evidence on Return on Equity

In its Application, the Company requested approval for its rates to be set using a rate of return on common equity of 10.75%. This request was based upon and supported by the direct testimony of CWSNC witness D'Ascendis. In his rebuttal testimony, witness D'Ascendis reduced his recommended rate of return on common equity to 10.20% based upon his updated analyses. This rate of return on common equity compares to a 9.75% rate of return on common equity underlying CWSNC's current rates. Public Staff witness Hinton, in his direct testimony, recommended a rate of return on common equity for CWSNC of 9.00%. In his supplemental testimony, witness Hinton revised and increased his recommended return on common equity to 9.10%.

Direct and Rebuttal Testimony of Dylan W. D'Ascendis (CWSNC)

Company witness D'Ascendis recommended in his direct testimony a rate of return on common equity of 10.75%. This 10.75% was based upon his indicated cost of common equity of 10.35%, plus a recommended size adjustment of 0.40%. In his rebuttal testimony, witness D'Ascendis provided an updated analysis reflecting current investor expectations and reduced his recommended rate of return on common equity to 10.20%, including his recommended 0.40% size adjustment.

CWSNC 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 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 and rebuttal testimony are as follows:

Summary of D'Ascendis Pre-Filed Testimony on Common Equity Cost Rate		
	Direct Testimony	Rebuttal Testimony
Discounted Cash Flow Model	8.70%	8.81%
Risk Premium Model	10.62%	10.12%
Capital Asset Pricing Model	10.21%	9.35%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Proxy Group	11.78%	11.29%
Indicated Common Equity Cost Rate Before Adjustment	10.35%	9.80%
Size Adjustment	0.40%	0.40%
Recommended Common Equity Cost Rate After Adjustment	10.75%	10.20%

He concluded that a common equity cost rate of 9.80% for CWSNC is indicated before any Company-specific adjustments. He then adjusted this indicated rate 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 10.20%.

CWSNC witness D'Ascendis testified the six companies in his Utility Proxy Group were: American States Water Co.; American Water Works Co., Inc.; Artesian Resources, Inc.; California Water Service Group; Middlesex Water Co.; and York Water Co.

CWSNC 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 October 18, 2019, divided by the average of closing market prices for the 60 trading days ending October 18, 2019.[1] He made an adjustment to the dividend yield because dividends are paid periodically, usually quarterly.

For CWSNC witness D'Ascendis' DCF growth rate he testified he only used analysts' five-year forecasts of earning per share (EPS) growth. He testified the mean result of his application of the single-stage DCF model is 8.73%, the median result is 8.88%, and the average of the two is 8.81% for his Utility Proxy Group as shown on D'Ascendis Rebuttal Exhibit 1, Schedule DWD-1R, page 3. He testified in arriving at a conclusion for the DCF-indicated common equity cost rate for his Utility Proxy Group, he relied on an average of the mean and the median results of the DCF.

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 Risk Premium Model Using an Adjusted Total Market Approach. He testified the PRPM estimates the risk/return relationship directly, as the predicted equity risk premium is generated by the prediction of volatility or risk. He testified 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 April 2019. He testified he added the forecasted 30-year U.S. Treasury Bond yield, 2.64% to each company's PRPM-derived equity risk premium to arrive at an indicated cost of common equity. His rebuttal mean PRPM indicated common equity cost rate for the Utility Proxy Group is 11.30%, and the median is 10.38%. He relied on the average of the mean and median results of the Utility Proxy Group PRPM to calculate a cost of common equity rate of 10.84% as shown on D'Ascendis Rebuttal Exhibit 1, Schedule DWD-1R, page 11, column (5).

CWSNC witness D'Ascendis testified 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 in his rebuttal testimony the adjusted prospective bond yield for the Utility Proxy Group to be 4.01% as shown on D'Ascendis Rebuttal Exhibit 1, Schedule DWD-1R, page 12, line 5, and the average equity risk premium to be 5.38% resulting in risk premium derived common equity to be 9.39% for his RPM using his Total Market Approach.

For his CAPM, witness D'Ascendis testified he applied both the traditional CAPM and the empirical CAPM (ECAPM) to the companies in his Utility Proxy Group and averaged the results. He testified the model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by the beta coefficient. 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

[1] See Schedule DWD-1R, page 3, footnote 1

coefficients of the Utility Proxy Group companies as reported by Value Line Investment Survey (Value Line).

CWSNC witness D'Ascendis in his rebuttal testified the risk-free rate adopted for both applications of the CAPM at 2.64%. This risk-free rate of 2.64% 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 beginning with the fourth calendar quarter of 2019 and ending with the first quarter in 2021, and long-term projections for the years 2021 to 2025, and 2026 to 2030. D'Ascendis Rebuttal Exhibit 1, DWD-1R, page 22, column (5), and page 23, column (2).

Witness D'Ascendis testified on rebuttal that the mean result of his CAPM/ECAPM analyses is 9.39%, the median is 9.31%, and the average of the two is 9.35%. Witness D'Ascendis testified that, consistent with his reliance on the average of his mean and median DCF results, the indicated common equity costs rate using the CAPM/ECAPM is 9.35%.

Witness D'Ascendis also selected 11 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. In his rebuttal testimony, witness D'Ascendis' DCF result was 11.63%, his RPM cost rate was 11.41%, and his CAPM/ECAPM cost rate was 10.44%. Witness D'Ascendis testified that the average of the mean and median of these models was 11.29%, which he used as the indicated common equity cost rate for the Non-Price Regulated Proxy Group.

Based on the results of the application of multiple cost of common equity models to the Utility Proxy Group and the Non-Price Regulated Proxy Group, witness D'Ascendis testified that the reasonable, appropriate and indicated cost of equity for CWSNC before any adjustment for relative risk was 9.80%.

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). This resulted in a size-adjusted cost of common equity for CWSNC of 10.20%.

Additionally, witness D'Ascendis stated that he had reviewed the Commission's Sub 360 Order regarding the issues of the use of the PRPM, the ECAPM, the use of a non-price regulated proxy group, and the applicability of a size adjusted cost of common equity for CWSNC. In response to these concerns, witness D'Ascendis provided testimony further supporting the inclusion of such factors in determining his recommended return on equity.

Specifically, in terms of the PRPM, he addressed the Commission's concerns about using a specific statistical package to calculate the PRPM results, which made the Commission skeptical that investors would place significant weight on the model. He explained that the general autoregressive conditional heteroskedasticity (GARCH) model used for the PRPM has been in the public domain since the 1980s and is available in several statistical packages which are not financially prohibitive for investors.

In response to the Commission's concerns regarding the ECAPM, which were that there was not enough evidence in the record as to why the ECAPM was superior to the CAPM, witness D'Ascendis provided substantially more information on the subject than what was presented in Sub 360.

In response to the Commission's concerns regarding the use of non-price regulated companies, which were that the non-price regulated companies were not of similar risk to the utility proxy group, witness D'Ascendis provided an additional measure of risk to show that, indeed, his non-price regulated proxy group was similar in total risk to the utility proxy group. The study showed that the non-price regulated proxy group's mean and median coefficient of variation (CoV), of net profit were within the range of CoVs of net profit set by the utility proxy group. The coefficient of variation is often used by investors and economists to determine volatility (i.e. risk) and the use of net profit directly ties to earnings and stock prices.

Finally, witness D'Ascendis responded to the Commission's concerns regarding the size adjustment which were whether the size studies presented in the record were applicable to utilities, and that the selection of a 40-basis point adjustment from an indicated 461 basis point risk premium was rather arbitrary. In order to provide more information to the Commission in this case, witness D'Ascendis conducted a study on whether the size effect is in fact applicable to utilities. His study included the universe of water, gas, and electric companies included in Value Line Standard Edition. From each of the utilities' Value Line Ratings & Reports, witness D'Ascendis calculated the 10-year CoV of net profit (a measure of risk) and current market capitalization (a measure of size) for each company. After ranking the companies by size (largest to smallest) and risk (least risky to most risky), he made a scatter plot of the data, as shown on Chart 1 in his direct testimony.

Witness D'Ascendis testified that, as shown in his Chart 1 of his direct testimony, as company size decreases (increasing size rank), the CoV increases, linking size and risk for utilities. The R-Squared value of 0.0962 means that approximately 10% of the change in risk rank is explained by the size rank. While a 0.0962 R-Squared value does not appear to have strong explanatory power, the average R-Squared value of the Utility Proxy Group's beta coefficient is 0.0794. The selection of a 40-basis point upward adjustment based on its difference in size given an indicated risk premium of approximately 400 basis points is consistent with the approximate 0.10 R-Squared value of the size study applicable to utilities. With this additional information, witness D'Ascendis stated that he hoped the Commission would revisit this concern in its Order in this case.

Witness D'Ascendis' rebuttal testimony criticized the testimony of witness Hinton's approach to estimating CWSNC's required return on equity for a number of perceived shortcomings, including Hinton's:

(a) Inclusion of a gas proxy group to determine a rate of return on common equity for a water utility;
(b) Misapplication of the discounted cash flow model;
(c) Misapplication of the risk premium model;
(d) Misapplication of the capital asset pricing model;
(e) Misapplication of the Comparable Earnings Model;
(f) Failure to account for size-specific risks; and

(g) Opinion that the approval of the Company's requested consumption adjustment mechanism (CAM) in this proceeding requires a downward adjustment to the rate of return on common equity.

Tr. vol. 8, 267–68.

CWSNC Witness D'Ascendis Cross-Examination

CWSNC witness D'Ascendis testified on cross-examination that in the Middlesex Water Company, New Jersey general rate case decided in July 2015, he recommended a specific rate of return on common equity of 10.40%, but that a rate of return on common equity of 9.75% was approved which was 65 basis points less than his recommendation. Witness D'Ascendis testified that in the Carolina Water Service, Inc. South Carolina 2015 general rate case where his recommended rate of return on common equity range was 10.00% to 10.50%, the approved rate of return on common equity was 9.34% which was 91 basis points below the midpoint of his recommended range.

CWSNC witness D'Ascendis further testified on cross-examination that in the Middlesex Water Company, New Jersey general rate case decided in March 2018, his recommended specific rate of return on common equity was 10.70%, and a 9.60% rate of return on common equity was approved whereby his recommended rate of return on common equity was 110 basis points above the approved rate of return on common equity. He testified that the 2018 South Carolina decision for Carolina Water Service, Inc. of South Carolina was the only one of the fifteen listed return on equity decisions, that a commission approved an allowed rate of return on common equity within his recommended range. He also testified that in the recent CWSNC general rate case, order dated February 21, 2019, his recommended rate of return on common equity range was 10.80% to 11.20%, with a midpoint of 11.00%, which was 125 basis points above the Commission approved rate of return on common equity of 9.75%.

Witness D'Ascendis testified on cross-examination that the authorized rates of return on equity for all 15 decisions averaged 127 basis points below his recommended rates of return on equity, and after removing a 2016 outlier case in Missouri where he was 360 basis points above the approved rate of return on common equity, the average difference between falls to 110 basis points. He further testified on cross-examination that his rebuttal specific return on equity recommendation of 10.20% less the 110 basis points, would be the same number as Public Staff witness Hinton's recommended 9.10% rate of return on common equity.

Witness D'Ascendis also testified that Public Staff D'Ascendis Cross-Examination Exhibit 1, page 2 listed the RRA approved rates of return on equity for the last three years for his Utility Proxy Group companies with approved average rates of return on equity of 9.42%.

Witness D'Ascendis testified that as shown on Public Staff D'Ascendis Cross-Examination Exhibit 2, which was a RRA summary of commission approved rates of return on equity from January 2014 through June 30, 2019, the average approved return on equity was 9.50% for 30 return on equity decisions in the most recent three- year period July 1, 2016 through June 30, 2019.

With respect to his recommended 40 basis point size adjustment, witness D'Ascendis testified on cross-examination that he knew CWSNC served approximately 50,000 customers in North Carolina, was the second largest Commission regulated water and wastewater utility in North Carolina, and the two next largest companies serve approximately 7,000 customers each.

Witness D'Ascendis testified he was aware CWSNC did not have any industrial customers, and that more than 99.5% of its customers were residential plus some small stores and some schools. He testified that CWSNC was geographically diversified in North Carolina with systems along the North Carolina coast, the Piedmont and throughout the mountains.

Witness D'Ascendis further testified on cross-examination that CWSNC obtains all its debt through its parent, Utilities, Inc., and that CWSNC does not go into the debt market. He testified that Utilities Inc. is owned by Corix. Witness D'Ascendis read into the record sections of the pre-filed testimony of Corix CEO and President Gordan Barefoot, which stated Corix provides to CWSNC a full suite of support services, and Corix provides access to favorable terms for debt financing in capital markets. Both the Public Staff and CWSNC used the Utilities, Inc. capital structure and debt costs for CWSNC in this general rate case.

Witness D'Ascendis testified that based on Public Staff D'Ascendis Cross-Examination, Exhibit 4, that the Utilities, Inc. has common equity of $280.2 million. When multiplied by the D'Ascendis Utility Proxy Group market to book ratio of 347.3%, the result is a market capitalization for Utilities, Inc. of $973.3 million. Witness D'Ascendis testified that this market capitalization of three of the companies in the D'Ascendis Utility Proxy Group; those companies being Artesian Resources Corporation at $316.0 million, York Water Company at $440.0 million, and Middlesex Water Company at $951.0 million.

CWSNC witness D'Ascendis on cross-examination further testified Public Staff D'Ascendis Cross-Examination Exhibit 5 was a comparison of the growth in dividends and stock market prices of the D'Ascendis Proxy Group of companies from April 15, 2011 to November 29, 2019. During that period dividend and stock price movements were as follows:

Company	Dividend Growth	Share Price Appreciation
American States Water	126%	378%
American Water Works	127%	419%
Artesian Resource Group	32%	91%
California Water Service	27%	173%
Middlesex Water Company	29%	243%
York Water Co.	36%	163%
Six Company Average	59%	245%

Witness D'Ascendis testified that he agreed that stock market prices have increased materially since April 2011, and dividend amounts have lagged way behind. He further testified that dividend yields are one of the two major components of the DCF.

During cross-examination CWSNC witness D'Ascendis also testified as to the stock price increases subsequent to the California Public Utilities Commission Order dated March 22, 2018 which approved a 9.20% rate of return on common equity for California American Water Co., a wholly-owned subsidiary of American Water Works; a 9.20% rate of return on common equity for California Water Service Co.; an 8.90% rate of return on common equity for Golden State Water Co., a wholly-owned subsidiary of American States Water; and an 8.90% rate of return on common equity for San Jose Water Co. The stock market percentage increases for the period March 22, 2018 to November 29, 2019, were: American Water Works 51.0%, American States Water 56.6%, California Water Service 36.3% and San Jose Water 33.1%, as shown on Public Staff D'Ascendis Cross-Examination Exhibit 6.

Witness D'Ascendis also testified on cross-examination about the significant decrease in the yields of 30-year Treasury Bond and A-Rated Public Utility Bonds as shown on Public Staff D'Ascendis Cross-Examination Exhibit 7. During the one-year period September 2018 to September 2019, the yields on A Rated Public Utility Bonds decreased from 4.32% to 3.37%, a decrease of 95 basis points from the previous CWSNC general rate case expert witness hearing heard before the Commission on October 16, 2018. Witness D'Ascendis' risk free 30-year Treasury Bond projected yield in this current case, shown in rebuttal exhibits filed on November 20, 2019, Schedule DWD-1R, page 22 was 2.64% compared to the 3.74% in September 2018, as stated in his prior Sub 360 CWSNC case testimony in D'Ascendis Rebuttal Exhibit 1, Schedule DWD-1R, page 11, column 6, and page 22, footnote 2, resulting in a bond yield decrease between his two rebuttal testimonies of 110 basis points. He further testified that as of November 29, 2019, the actual 30-year Treasury Bond yield was 2.19% compared to the October 16, 2018 actual 30-year Treasury Bond yield of 3.32%, a decrease of 113 basis points.

With respect to the non-price regulated companies in witness D'Ascendis' testimony for which he performed DCF, Risk Premium and CAPM analyses, he testified on cross-examination that these companies had competition unlike CWSNC, which has franchises protecting it from competition by other investor owned water utilities. Witness D'Ascendis testified that each time he has presented the non-priced regulated company analyses, the Commission has rejected and given no weight to these analyses.

Witness D'Ascendis testified that the Commission in CWSNC's February 19, 2019, Sub 360 Order found credible, probative, and entitled to substantial weight to his DCF, Total Market Risk Premium, and Traditional CAPM. He testified that his rebuttal exhibits in this case for these same analyses stated DCF 8.81%, Total Market Risk Premium 9.39%, Traditional CAPM 8.90%, with the average of these three of his models being 9.03%, all as shown on Public Staff D'Ascendis Cross-Examination Exhibit 10.

In response to a request by Chair Mitchell, CWSNC witness D'Ascendis filed a Late Filed Exhibit on December 13, 2019, showing the effect on each of his models using witness Hinton's 2.53% interest rate as the current yield for 30-year Treasury Bonds rather than the projected yields in witness D'Ascendis' rebuttal exhibits. This D'Ascendis On-the-Record Data Request provided the following results:

	D'Ascendis Late-Filed Exhibit #1
Discounted Cash Flow Model	8.81%
Risk Premium Model	10.00%
Capital Asset Pricing Model	9.29%
Cost of Equity Models Applied to ComparableRisk, Non-Price Regulated Proxy Group	11.16%
Indicated Common Equity Cost Rate Before Adjustment	9.75%
Size Adjustment	0.40%
Recommended Common Equity Cost RateAfter Adjustment	10.15%

Public Staff Witness Hinton Testimony

Public Staff Director of Economic Research John R. Hinton testified the Public Staff recommends an overall rate of return of 7.20%, based on a capital structure consisting of 50.90% long-term debt at a cost rate of 5.36% and 49.10% common equity at a cost rate of 9.10%. He testified his recommendations result in pre-tax interest coverage equaling 3.1 times and a funds flow to debt ratio of 25.0%, which should qualify for a single "A" bond rating.

Witness Hinton described the current financial market conditions, testifying that the cost of financing is much lower today than in the more inflationary period of the 1990s. More recently, the continued low rates of inflation and expectations of future low inflation rates have contributed to even lower long-term interest rates. He testified that according to Moody's Bond Survey, yields on long-term "A" rated public utility bonds have fallen 88 basis points from 4.25% on February 21, 2019, the date of the order in Sub 360, as compared to 3.37% for September 2019. He testified that by the close of this proceeding, CWSNC will have received five rate increases over the last six years in Docket Nos. W-354, Sub 360, Sub 356, Sub 344, and Sub 336. He further testified relative to the filing of the cost of capital settlement in the CWSNC January 2014 rate case in Docket No. W-354, Sub 336, yields on Moody's A-rated utility bonds are 126 basis points lower than the average 4.63% yield observed during the CWSNC January 2014, as illustrated by Hinton Exhibit JRH-1.

Witness Hinton testified that interest rates on various loans bave fallen as the yields on treasury securities have declined since the Commission issued its order on February 21, 2019. The graph on page 15 of witness Hinton's direct testimony shows the lower yields that on average are over 100 basis points lower for all durations except for a minor increase in 90-day treasury bills. He testified that the average decrease in treasury bonds of 5-, 7-, 10-, 20-, and 30-year bonds is 111 basis points. He testified while Utilities, Inc., Corix, and its ultimate parent, the British Columbia Investment Management Corporation (BCIMC) generally cannot obtain capital at these interest rates, the falling yields are indicators of the declining cost of debt capital.

Public Staff witness Hinton testified that the current lower interest rates, especially for longer-term securities, 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 within the securities markets. He testified that 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 ten years or more has paralleled the decreases in investor required rates of return on common equity.

Public Staff witness Hinton testified that he does not rely on interest rate forecasts. Rather, he believes 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 in the marketplace price bonds based upon expectations on demand and supply of capital, 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 rates to determine utility rates. He presented a portion of the testimony of Aqua North Carolina, Inc. witness Pauline Ahern in the 2013 Aqua rate case, Docket No. W-218, Sub 363. In that case she identified several interest rate forecasts by Blue Chip Financial Forecasts of 30-year Treasury Bond yields that were predicted to rise to 4.3% in 2015, 4.70% in 2016, 5.20% in 2017, and 5.50% for 2020-2024. He presented the graph 30-Year US Treasury Bonds on page 18 of his direct testimony, which showed in 2015, the range was approximately 2.50% to 3.10%, in 2016 the range was approximately 2.50% to 3.10%, and in 2017 the range was approximately 2.25% to 3.10%. Witness Hinton testified that similar overestimated forecasts can be identified in witness D'Ascendis' Exhibit DWD-4 in the CWSNC's 2018 rate case where the Blue-Chip consensus forecast predicted the 30-year Treasury Bonds would rise to 3.80% by the third quarter of 2019. According to the Federal Reserve, the highest observed yield on 30-year Treasury Bonds for the third quarter of 2019 is 2.65%, and the average for the quarter was 2.29%. He testified that these types of errors make these interest rate forecasts inappropriate for ratemaking.

Public Staff witness Hinton testified that he used the discounted cash flow (DCF) model and the Risk Premium model 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. Witness Hinton testified that the DCF model is based on the theory that the price of the investment will equal the discounted cash flows of returns. 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 focused on the expected stream of dividends.

Witness Hinton testified that he applied the DCF method to a comparable group of seven water utilities followed by Value Line Investment Survey. He testified that the standard edition of Value Line covers eight water companies. He excluded Consolidated Water Co. due to its significant overseas operations. Witness Hinton included a group of nine natural gas local distribution companies (LDCs) in his DCF analysis stating these LDCs exhibit risk measures similar to his proxy group of water companies.

Public Staff 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 July 26, 2019, through October 18, 2019. 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 1.7% for his proxy group of water utilities and 2.6% for the LDC group utilities.

To calculate the expected growth rate component of the DCF, Public Staff witness Hinton employed the growth rates of his proxy group in earnings per share (EPS), dividends per share (DPS), and book value per share (BPS) as reported in Value Line over the past ten and five years. He also employed the forecasts of the growth rates of his water and LDC proxy groups in EPS, DPS, and BPS 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 includes 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.

Public Staff witness Hinton testified that he also incorporated the consensus of various analysts' forecasts of five-year EPS growth rate projections as reported in Yahoo Finance. He testified the dividend yields and growth rates for each of the companies and for the average for his comparable proxy groups are shown in Exhibit JRH-4.

Public Staff witness Hinton concluded that based upon his DCF analysis that a reasonable expected dividend yield is 1.7% with an expected growth rate of 6.0% to 7.0%. He testified that his DCF analysis produces a cost of common equity for his comparable proxy group of water utilities of 7.7% to 8.7%. Based upon the DCF analysis for the comparable group of LDCs, he determined that a reasonable expected dividend yield is 2.6%, with an expected growth rate of 5.7% to 6.7%, which yields a range of results of 8.3% to 9.3% for the cost of equity.

He testified that his ultimate DCF based cost of equity is based on the average estimates for the two groups of companies, which he summarized in his Hinton Exhibit 8 that quantifies an approximate range of DCF based cost of equity estimates of 8.48% to 8.80% for his DCF based cost of equity estimate of 8.64%.

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 utilities commissions that is published by the Regulatory Research Associates, Inc. (RRA), within SNL Global Market Intelligence. 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 2019. 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 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. He testified that it is reasonable to conclude that the approved allowed returns are good estimates of the cost of equity.

Public Staff witness Hinton testified that the summary data of risk premiums shown on his Exhibit JRH-5, page 1 of 2, indicates that the average risk premium is 5.00%, 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 8.70%, a maximum cost of equity of 9.48%, and a minimum cost of equity of 7.44%. To better estimate the current cost of equity, he performed a statistical regression analysis as shown on Exhibit JRH 5, page 2 of 2 in order to quantify the relationship of allowed equity returns and bond costs. He testified that by applying the risk premium to the current utility bond cost of 3.71%, resulted in a current estimate of the equity risk premium of equity of 9.57%.

Public Staff witness Hinton concluded that based on all of the results of his DCF model that indicate a cost of equity from 8.48% to 8.80% with a central point estimate of 8.64%, and the risk premium model that indicates a cost of equity of 9.57%, he determined that the investor required rate of return on common equity for CWSNC is between 9.11% which he rounded to 9.10% as shown on Hinton Exhibit 8.

Public Staff 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 equity. He testified that based on his recommended capital structure, cost of debt, and equity return of 9.10%, the pre-tax interest coverage ratio is approximately 3.1 times. He testified that this tax interest coverage and a funds flow to debt ratio of 25.0%, as shown on Supplemental Hinton Exhibit 10, should allow CWSNC to qualify for a single "A" bond rating.

Witness Hinton also performed a comparable earnings analysis and a CAPM analysis solely as checks on the results of this DCF and Risk Premium Regression Analysis. He testified that his comparable earnings analysis for a group of eight water utilities and nine LDC companies produced a five-year average return on equity of 9.83%. He testified that a weakness is that actual earned rates of return can be impacted by factors outside the company's control, such as weather, inflation, and tax changes, including deferred income taxes. These unforeseen developments can cause a company's earned rate of return to exceed or fall short of its cost of capital during any certain period making this method somewhat less reliable than other cost of capital methods, and it suffers from circular reasoning. In addition, he testified that earned rates of return on equity may often include non–regulated income. He testified that his CAPM analysis utilizing his preferred geometric mean return produced return on equity estimates of 7.65% and 7.68% that are at the low end of CWSNC's cost of equity. As such, he testified his CAPM provides a limited check on his recommended cost of equity.

Witness Hinton in his direct testimony had a recommended a rate of return on common equity of 9.10% with a downward 10 basis point adjustment to reflect reduced risk due to the consumption adjustment mechanism CWSNC applied for in this proceeding. His resulting recommended allowed rate return on equity was thus 9.00%. After CWSNC withdrew its request for a consumption adjustment mechanism, witness Hinton filed supplemental testimony withdrawing this 10-basis point downward adjustment.

Witness Hinton testified that his recommended return on common equity takes into consideration the impact of the water and sewer system improvement charges (WSIC and SSIC) pursuant to N.C.G.S. § 62-113.12 on CWSNC's financial risk. He testified that the WSIC and SSIC mechanisms provide the ability for enhanced cost recovery of the eligible capital improvements which reduces regulatory lag through incremental and timely rate increases. He testified he believes this mechanism is seen by debt and equity investors as supportive regulation that mitigates business and regulatory risk. Witness Hinton testified that he believes that this mechanism is noteworthy and is supportive of his 9.10% 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 CWSNC is owned by Corix Infrastructure, Inc. (Corix), which is owned by BCIMC. Corix has a significant influence over the balances of common equity and long-term debt of Utilities, Inc. and CWSNC. Corix determines the amounts of dividend payments to BCIMC and the frequency of those payments. 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 as 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. Witness Hinton testified that CWSNC operates in the water and sewer industry, where expensive bottled water provides the only alternative to utility service. It is factually correct that rating agencies and investors add a risk factor for small companies with relatively limited capital resources; however, the inherent protection from competition removes this risk that would otherwise be a concern to investors.

Witness Hinton noted that he also testified to these same size adjustment concerns in the last CWSNC rate case, Sub 360, where the Commission found that a size adjustment was not warranted. He testified that similar arguments were made in a 1997 CWS System, Inc., rate case, Docket No. W-778, Sub 31, by witness Hanley of AUS Consultants, who relied on similar cost of capital methods as witness D'Ascendis, as noted on pages 824-25 in its Eighty-Seventh Report of Orders and Decisions. In CWSNC's 1994 rate case, Docket No. W-354, Sub 128, the Commission was not persuaded to accept an adjustment for small size and its elevated risk, as noted on page 520 in its Eighty-Fourth Report on Orders and Decisions. Tr. vol. 7, 785–86. In a rate case brought by North Carolina Natural Gas, Inc., Docket No, G-21, Sub 293, the explicit consideration of the small size of a regulated utility was argued before this Commission. In its December 6, 1991 Order in that case, the Commission disagreed with the Company witness who testified that the Company's small size warranted the selection of other small sized companies in his proxy group.

Witness Hinton testified that while there are published studies that address how the small size of a company relates to higher risks, he is aware of only one study by Dr. Annie Wong[1] that focuses on the size of regulated utilities and risk. He testified that Dr. Wong has tested the data for a size premium in utilities and concluded that "unlike industrial stocks, utility stocks do not exhibit a significant size premium. As explained, there are several reasons why such a size premium would not be attributable to utilities because they are regulated closely by state and federal agencies and commissions, and hence, their financial performance is monitored on an ongoing basis by both the state and federal governments." Tr. vol. 7, 187.

Public Staff Witness Hinton Cross-Examination

Witness Hinton testified on cross-examination that the electric and natural gas industries in North Carolina have a number of surcharge rate adjustment mechanisms available to them which serve to enhance revenue recovery and thereby stabilize earnings and that those mechanisms also employ deferral accounting as part of the true-up process. Witness Hinton also testified that all utilities are concerned with regulatory lag and that surcharge rate adjustment mechanisms reduce regulatory lag, . . . maybe significantly " Tr. vol. 7, 105, 93.

Witness Hinton also testified on cross-examination that during "the last couple years your [CWSNC's] earned returns have been less than your allowed returns." *Id.* at 104.

Witness Hinton further stated that he considered his initial proposal (which he withdrew when CWSNC withdrew its request to implement a CAM) to impose a 10-basis point downward adjustment with respect to his recommended rate of return on common equity in consideration of the Company's initially-proposed CAM to be a "material" adjustment. *Id.* at 111.

Witness Hinton also testified on cross-examination that the 23-basis point reduction in CWSNC's cost of long-term debt from 5.59% at the time the Company filed its Verified Rate Case Application to 5.36% at September 30, 2019; was "material." *Id.* at 133.

Law Governing the Commission's Decision on Return on Equity

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 common equity. *See, e.g., CUCA I,* 348 N.C. at 466, 500 S.E.2d 707. In order to reach an appropriate independent conclusion regarding the rate of return on common equity the Commission should evaluate the admitted evidence, particularly that presented by conflicting expert witnesses. *State ex rel. Utils. Comm'n v. Cooper,* 366 N.C. 484, 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 Company witness D'Ascendis and Public Staff witness Hinton. No rate of return on common equity expert evidence was presented by any other party.

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[1] Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," Journal of the Midwest Finance Association, pp. 95-101, (1993).

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

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

DEC Sub 1146 Order at 50; *see also State ex rel. Utils. Comm'n v. Gen. Tel. Co.*, 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972) (*General Telephone*). As the North Carolina Supreme Court held in *General Telephone*, these factors constitute "the test of a fair rate of return declared" in *Bluefield* and *Hope*. *Id.*

The rate of return on common equity is, in fact, a cost. The return that equity investors require represents the cost to the utility of equity capital.

> [T]he cost of capital to the utility is synonymous with the investor's return, and the cost of capital is the earnings which must be generated by the investment of that capital in order to pay its price, that is, in order to meet the investor's required rate of return.

Morin, Roger A., *Utilities' Cost of Capital* 19-21 (Public Utilities Reports, Inc. 1984). "The term 'cost of capital' may [also] 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), at 388.

Long-standing decisions of the North Carolina Supreme Court have recognized that the Commission's subjective judgment is a necessary part of determining the authorized rate of return on common equity. *Public Staff*, 323 NC at 490, 374 S.E.2d at 369. Likewise, the Commission has observed as much in exercising its duty to determine the rate of return on common equity, noting that such determination is not made by application of any one simple mathematical formula:

> Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the

commissions are supposed to consider in making their Decisions, but no weights have been assigned.

The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.

In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:

> There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.

As long as the allowed return falls within this zone, therefore, it is just and reasonable . . . . It is the task of the commissions to translate these generalizations into quantitative terms.

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

Order Granting General Rate Increase, *Application of Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina,* No. E-2, Sub 1023, at 35-36 (N.C.U.C. May 30, 2013), *aff'd, State ex rel. Utils. Comm'n v. Cooper,* 367 N.C. 444, 761 S.E.2d 640 (2014) (2013 DEP Rate Case Order) (additions and omissions after the first quoted paragraph in original).

Moreover, in setting rates the Commission must not only adhere to the dictates of both the United States and North Carolina Constitutions, but, as has been held by the North Carolina Supreme Court, it must set rates as low as possible consistent with constitutional law. *State ex rel.*

Utils. Comm'n v. Pub. Staff-N. Carolina Utils. Comm'n, 323 N.C. 481, 490, 374 S.E.2d 361, 370 (1988) (*Public Staff*). Further, the North Carolina General Assembly has provided that the Commission must also set rates employing a multi-element formula set forth in N.C.G.S. § 62-133. The formula requires consideration of elements beyond just the rate of return on equity element, and it inherently necessitates that the Commission make many subjective determinations, in addition to the subjectivity required to determine the rate of return on equity. The subjective decisions the Commission must make as to each of the elements of the formula can and often do have multiple and varied impacts on all of the other elements of the formula. In other words, the formula elements are intertwined and often interdependent in their impact to the setting of just and reasonable rates.

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

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

The North Carolina Supreme Court has interpreted the above-emphasized language as requiring the Commission to make findings regarding the impact of changing economic conditions on customers when determining the proper rate of return on common equity for a public utility. *Cooper I*, 366 N.C. at 495, 739 S.E.2d at 548. The Commission must exercise its subjective judgment so as to balance two competing rate of return on common equity-related factors—the economic conditions facing the Company's customers and the Company's need to attract equity financing on reasonable terms in order to continue providing safe and reliable service. 2013 DEP Rate Case Order at 35-36. The Commission's determination in setting rates pursuant to N.C.G.S § 62-133, which includes the fixing of the rate of return on common equity, always takes into account affordability of public utility service to the using and consuming public. The impact of changing economic conditions on customers is embedded in the testimony of expert witnesses regarding their analyses of the rate of return on common equity using various economic models widely used and accepted in utility regulatory rate-setting proceedings. 2013 DEP Rate Case Order, at 38. Further,

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

> equity when the general body of ratepayers is in a better position to pay than at other times . . . .

Id. at 37. Economic conditions existing during the modified test year, at the time of the public hearings, and at the date of the issuance of the Commission's order setting rates will affect not only the ability of the utility's customers to pay rates, but also the ability of the utility to earn the authorized rate of return during the period the new rates will be in effect. However, in setting the rate of return, just as the Commission is constrained to address the impact of difficult economic times on customers' ability to pay for service by establishing a lower rate of return on common equity in isolation from the many subjective determinations that must be made in a general rate case, it likewise is constrained to address the effect of regulatory lag[1] on the Company by establishing a higher rate of return on common equity in isolation. Instead, the Commission sets the rate of return considering both of these negative impacts taken together in its ultimate decision fixing a utility's rates.

Thus, in summary and in accordance with the applicable law, the Commission's duty under N.C.G.S. § 62-133 is to set rates as low as reasonably possible to the benefit of the customers without impairing the Company's ability to attract the capital needed to provide reliable electric service and recover its cost of providing service. The Commission is guided by this premise when it makes it determination of the appropriate rate of return on common equity.

It is against this backdrop of overarching principles that the Commission analyzes the evidence presented in this case.

Discussion and Application of Law to the Facts in this Case Regarding the Issue of Rate of Return on Common Equity

The Commission has carefully evaluated the 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:

[1] Regulatory lag exists where a utility's realized, earned return is less than its authorized return negatively affecting the shareholder's return on investment as other expenses and debts owed are paid ahead of investor return.

Utility Proxy Group	D'Ascendis Rebuttal Exhibits	D'Ascendis Late-Filed Exhibits	Hinton
DCF	8.81%	8.81%	8.64%
Risk Premium	10.12%	10.00%	9.57%
PRPM	10.84%	10.73%	
Total Market RPM	9.39%	9.27%	
CAPM	9.35%	9.29%	7.65-8.96%*
Traditional CAPM	8.90%	8.84%	
ECAPM	9.80%	9.74%	
Comparable Earnings	——	——	9.83%*
Non–Price Regulated Proxy Group	11.29%	11.16%	——
DCF	11.63%	11.63%	
Risk Premium	11.41%	11.23%	
CAPM	10.44%	10.39%	
Indicated on Return on EquityBefore Adjustment	9.80%	9.75%	9.10%
Size Adjustment	0.40%	0.40%	——
Recommended Return on Equity	10.20%	10.15%	9.10%

* Note: Provided solely as a check and not used in formulating this witness's recommended allowed rate of return on common equity.

The range of the rate of return on common equity recommendations from the two expert witnesses is 9.10% to 10.20%. Underlying the lower rate of return on common equity recommendation of 9.10%, is a rate of return on common equity range of 7.65% to 9.83%, according to witness Hinton's testimony concerning his cost of common equity analyses. Similarly, underlying the higher rate of return on common equity recommendation of 10.20% is a range of 8.81% to 11.29%, according to witness D'Ascendis' rebuttal testimony concerning his cost of common equity analyses. Such a wide range of estimates by expert witnesses is not atypical in proceedings before the Commission with respect to the return on the 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 interests of the party on whose behalf they are testifying. 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 doing so the Commission finds that the DCF (8.81%), Risk Premium (10.00%) and CAPM (9.29%) model results provided by witness D'Ascendis, as updated to use current rates in D'Ascendis Late-Filed Exhibit No. 1, as well as the risk premium (9.57%) analysis of witness

Hinton, are credible, probative, and are entitled to substantial weight as set forth below. The Commission further finds that the rate of return on common equity trends, particularly as embodied by data points in Public Staff D'Ascendis Cross-Examination Exhibits 1 and 2 to be credible, positive and corroborative evidence entitled to some weight. [1] Accordingly, the evidence presented concerning other authorized rates of return on equity, when put into proper context, lends substantial support and corroboration to a finding that a 9.50% rate of return on common equity is appropriate in this case.

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 8.81%, his CAPM model indicated a cost of equity of 9.29%, and his Risk Premium model indicated a cost of equity of 10.00%. The Commission finds and concludes that analyses using interest rate forecasts rely unnecessarily on projections. The Commission approves the use of current interest rates, rather than projected near–term or long–term interest rates. The Commission finds witness D'Ascendis' late-filed exhibit Risk Premium Model and his late-filed exhibit CAPM analysis using the current 30–year Treasury yields to be credible, probative and entitled to substantial weight.

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 2019. 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 cost 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 utility bond cost of 3.71% resulted in a current estimate of the cost of equity of 9.57%.

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[1] The Commission determines the appropriate rate of return on common equity based upon the evidence and particular circumstances of each case. However, the Commission believes that the rate of return on common equity trends and decisions by other regulatory authorities deserve some weight, as (1) they provide a check or additional perspective on the case-specific circumstances, and (2) the Companymust compete with other regulated utilities in the capital markets, meaning that a rate of return on commonequity significantly lower than that approved for other utilities of comparable risk would undermine the Company's ability to raise necessary capital, while a rate of return on common equity significantly higher than other utilities of comparable risk would result in customers paying more than necessary. In this proceeding, witness Hinton's risk premium analysis, as well as Public Staff D'Ascendis Cross-ExaminationExhibit No. 1, page 2 and No. 2 provide credible, positive and corroborative evidence.

The average of witness D'Ascendis' Utility Proxy Group late-filed exhibit DCF result of 8.81%, CAPM result of 9.29% and RPM result of 10.00% and witness Hinton's RPM of 9.57% is 9.42%. A return on common equity of 9.50% is thus supported by the average of the results of the four above-listed cost of equity models which the Commission finds are credible, probative, and entitled to consideration based on the record in this proceeding.

The Commission gives no weight to the DCF, CAPM and comparable earnings analyses of witness Hinton who presented his CAPM and comparable earnings methods only as a check on his DCF and Risk Premium Regression analyses. For reasons generally stated by witness D'Ascendis, the Commission concludes that witness Hinton's use of a proxy group of natural gas companies in his DCF and CAPM analyses is inappropriate for determining the appropriate return on equity in this case. The indicated returns on equity using the water proxy groups in witness Hinton's DCF (8.48%) and CAPM (7.65% to 8.96% with a midpoint of 8.31%) are outliers as they fall far below the other rate of return on common equity analyses in this proceeding.

Witness Hinton's comparable earnings analyses are not reliable as the earned rates of return on equity listed in Hinton Exhibit 6 contain non-regulated earnings and increased earnings resulting from deferred income taxes. Witness D'Ascendis on cross-examination testified that American States Water has significant operations in Army bases around the country and also has an electric utility. Although the California Utilities Commission on March 22, 2018, approved an 8.90% rate of return on common equity for Golden State Water Company which is a wholly-owned subsidiary of American States Water as shown on Public Staff D'Ascendis Cross-Examination Exhibit 6, American States Water achieved earned rates of return on equity of 11.40% in 2018 and 12.0% in 2019 as shown on Hinton Exhibit 6. In addition, although the most recent rate order for Middlesex Water Co. in New Jersey was issued on March 24, 2018, which approved a 9.60% rate of return on common equity as shown on Public Staff D'Ascendis Cross-Examination Exhibit 3, the Middlesex Water Co. earned rate of return on common equity for 2018 was 13.0% and 2019 earned rate of return on common equity was 12.0% as shown on Hinton Exhibit 6.

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 10 domestic, non-price regulated companies. The rebuttal results of the DCF, RPM, and CAPM applied to the non-price regulated proxy group are 11.63%, 11.23%, and 10.39%, respectively. The Commission concludes that these results are unreasonably high. Each of these results is higher than witness D'Ascendis' estimates of the cost of equity for his own Utility Proxy Group and deserves no weight. The Commission further concludes that given the difference in these results, the risk of the two groups is not equal and the Utility Proxy 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 premium methods applied to both of his proxy groups equals in his rebuttal 9.80% rate of return on common equity, witness D'Ascendis then adjusted the indicated cost of equity upward by 0.40% to reflect CWSNC's smaller size compared to companies in his Utility Proxy Group. He testified that the size of the company is a significant element of business risk for which investors expect to be compensated through higher returns. Witness D'Ascendis calculated his size adjustment as described in his prefiled direct testimony and stated that even though a 3.94% upward size

Witness D'Ascendis testified that the rate of unemployment has fallen substantially in North Carolina and the U.S. since late 2009 and early 2010, when the rates peaked at 10.00% and 12.00%, respectively. He testified that by April 2019, the unemployment rate had fallen to less than one-half of those peak levels: 3.30% nationally; and 3.60% in North Carolina.

Witness D'Ascendis 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 an average 12.86% (58 basis points higher than the State-wide average); by April 2019, it had fallen to 3.68% (8 basis points higher than the state-wide average).

Witness D'Ascendis testified that for real Gross Domestic Product 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's rate of growth. He testified that since the second quarter of 2015; however, North Carolina has consistently exceeded the national growth rate.

As to median household income, witness D'Ascendis testified that the correlation between North Carolina and the U.S. is relatively strong (approximately 87% from 2005 through 2018). Since 2009, the years subsequent to the financial crisis, median household income in North Carolina has grown at a similar annual rate as the national median income (2.32% vs. 2.65%).

Witness D'Ascendis summarized stating 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 that unemployment, at both the State and county level, continues to fall and remains highly correlated with national rates of unemployment; real Gross Domestic Product 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.

The Commission's review also includes consideration of the evidence presented by 23 witnesses during the public witness hearings, almost all of whom presently are customers of CWSNC. 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.

Based upon the general state of the economy and the continuing affordability of water and wastewater utility service, and after weighing and balancing factors affected by the changing economic conditions in making the subjective decisions required, the Commission concludes that an allowed rate of return on common equity of 9.50% will not cause undue hardship to customers even though some will struggle to pay the increased rates resulting from this decision. When the

Commission's decisions are viewed as a whole, including the decision to establish the rate of return on common equity at 9.50%, the Commission's overall decision fixing rates in this general rate case results in lower rates to consumers in the existing economic environment.[1]

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 noted 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 common equity of 9.50% instead of the 10.20% recommended by CWSNC witness D'Ascendis on rebuttal. 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, and thus, inure to the benefit of consumers' ability to pay their bills in this economic environment.

Despite the improving economic conditions and their effects on CWSNC's customers, the Commission recognizes the financial difficulty that an increase in CWSNC's rates may 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 common equity have a substantial impact on a utility's base rates. Therefore, the Commission has carefully considered changing economic conditions and their effects on CWSNC's customers in reaching its decision regarding CWSNC's approved rate of return on common equity.

The Commission 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 and concludes 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.

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[1] The Commission notes consumers pay rates, a charge in dollars per 1,000 gallons for the waterthey consume and a monthly flat rate for residential wastewater customers. They do not pay a "rate of return on equity," though it is a component of the Company's cost of providing service which is built into thebilled rates. Investors are compensated by earning a return on the capital they invest in the business. Per the Commission determination of the rate of return on common equity in this matter, investors will have theopportunity to be paid in dollars for the dollars they invested at the rate of 9.50%.

The Commission notes further that its approval of a rate of return on common equity at the level of 9.50% or for that matter at any level, is not a guarantee to the Company that it will earn a rate of return on common equity at that level. Rather, as North Carolina law requires, setting the rate of return on common equity at this level merely affords CWSNC the opportunity to achieve such a return. The Commission finds and concludes, based upon all the evidence presented, that the rate of return on common 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' direct testimony recommended the use of the actual capital structure of Utilities, Inc. of 52.04% long-term debt and 47.96% common equity as of March 31, 2019.

In his testimony Public Staff witness Hinton recommended a 50.90% long-term debt and 49.10% common equity capital structure based upon updated information provided by CWSNC concerning the Utilities, Inc. actual capital structure at September 30, 2019. The Partial Stipulation also supports a 50.90% long-term debt and 49.10% common equity capital structure. No other party presented evidence as to a different capital structure.

Accordingly, the Commission finds that the recommended capital structure of 49.10% common equity and 50.90% long-term debt is just and reasonable to all parties in light of all the evidence presented.

Cost of Debt

In its Application CWSNC proposed a cost rate for long-term debt of 5.59%. In his testimony, witness Hinton recommended the cost of debt 5.36% as of September 30, 2019. In addition, the Stipulation includes a cost of debt rate of 5.36%. No other party offered any evidence supporting a debt cost rate below 5.36%.

Therefore, the Commission finds that the use of a debt cost rate of 5.36% is just and reasonable to all parties based upon the evidence presented in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 60

Revenue Requirement

The following schedules summarize the gross revenue and overall rate of return that the Company should have a reasonable opportunity to achieve based on the increases in revenues approved in this Order for each rate entity. These schedules, illustrating the Company's gross revenue 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 364
Net Operating Income for a Return
For the Twelve Months Ended March 31, 2019
CWSNC Combined Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$33,852,232	$4,969,441	$38,821,673
Miscellaneous revenues	387,492	14,956	402,448
Uncollectibles	(271,142)	(38,638)	(309,780)
Total operating revenues	33,968,582	4,945,759	38,914,341
Operating Revenue Deductions:			
Salaries and wages – Maintenance	4,949,710	0	4,949,710
Purchased power	2,103,043	0	2,103,043
Purchased water and sewer	2,219,243	0	2,219,243
Maintenance and repair	3,120,935	0	3,120,935
Maintenance testing	544,432	0	544,432
Meter reading	206,176	0	206,176
Chemicals	693,596	0	693,596
Transportation	534,200	0	534,200
Operating expense charged to plant	(665,133)	0	(665,133)
Outside services – other	1,191,299	0	1,191,299
Salaries and wages – General	2,004,409	0	2,004,409
Office supplies & other office exp.	568,864	0	568,864
Regulatory commission expense	307,754	0	307,754
Pension and other benefits	1,600,158	0	1,600,158
Rent	330,308	0	330,308
Insurance	782,562	0	782,562
Office utilities	747,670	0	747,670
Miscellaneous	218,417	0	218,417
Depreciation expense	6,580,711	0	6,580,711
Amortization of CIAC	(1,476,955)	0	(1,476,955)
Amortization of PAA	(76,623)	0	(76,623)
Amortization of ITC	(579)	0	(579)
Franchise and other taxes	(655)	0	(655)
Property taxes	268,734	0	268,734
Payroll taxes	527,428	0	527,428
Regulatory fee	44,159	6,429	50,588
Deferred income tax	(69,128)	0	(69,128)
State income tax	75,474	123,484	198,958
Federal income tax	618,133	1,011,327	1,629,460
Rounding	0	1	1
Total operating revenue deductions	27,948,343	1,141,241	29,089,584
Net operating income for a return	$6,020,239	$3,804,518	$9,824,757

SCHEDULE II

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Original Cost Rate Base
For the Twelve Months Ended March 31, 2019
CWSNC Combined Operations

Item	Amount
Plant in service	$238,212,084
Accumulated depreciation	(57,897,943)
Net plant in service	180,314,141
Cash working capital	2,404,800
Contributions in aid of construction	(40,270,675)
Advances in aid of construction	(32,940)
Accumulated deferred income taxes	(5,995,444)
Customer deposits	(315,447)
Inventory	271,956
Gain on sale and flow back taxes	(417,811)
Plant acquisition adjustment	(837,878)
Excess book value	0
Cost-free capital	(261,499)
Average tax accruals	(143,198)
Regulatory liability for excess deferred taxes	(3,941,344)
Deferred charges	2,122,707
Pro forma plant	0
Original cost rate base	$132,897,368
Rates of return:	
Present	4.53%
Approved	7.39%

SCHEDULE III

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Statement of Capitalization and Related Costs
For the Twelve Months Ended March 31, 2019
CWSNC Combined Operations

	Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
		PRESENT RATES		
Long-Term Debt	50.90%	$ 67,644,760	5.36%	$3,625,759
Common Equity	49.10%	65,252,608	3.67%	2,394,480
Total	100.00%	$132,897,368		$6,020,239
		APPROVED RATES		
Long-Term Debt	50.90%	$ 67,644,760	5.36%	$3,625,759
Common Equity	49.10%	65,252,608	9.50%	6,198,998
Total	100.00%	$132,897,368		$9,824,757

SCHEDULE I-A
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Net Operating Income for a Return
For the Twelve Months Ended March 31, 2019
CWSNC Water Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$17,485,912	$1,785,873	$19,271,785
Miscellaneous revenues	189,818	5,357	195,175
Uncollectibles	(129,396)	(13,215)	(142,611)
Total operating revenues	17,546,334	1,778,015	19,324,349
Operating Revenue Deductions:			
Salaries and wages – Maintenance	2,684,228	0	2,684,228
Purchased power	1,048,858	0	1,048,858
Purchased water and sewer	1,478,502	0	1,478,502
Maintenance and repair	909,143	0	909,143
Maintenance testing	202,228	0	202,228
Meter reading	175,422	0	175,422
Chemicals	311,580	0	311,580
Transportation	283,615	0	283,615
Operating expense charged to plant	(360,703)	0	(360,703)
Outside services – other	654,506	0	654,506
Salaries and wages – General	1,086,991	0	1,086,991
Office supplies & other office expense	308,786	0	308,786
Regulatory commission expense	169,355	0	169,355
Pension and other benefits	867,766	0	867,766
Rent	178,706	0	178,706
Insurance	423,389	0	423,389
Office utilities	411,346	0	411,346
Miscellaneous	120,273	0	120,273
Depreciation expense	3,198,990	0	3,198,990
Amortization of CIAC	(704,302)	0	(704,302)
Amortization of PAA	(115,669)	0	(115,669)
Amortization of ITC	(328)	0	(328)
Franchise and other taxes	(3,473)	0	(3,473)
Property taxes	154,066	0	154,066
Payroll taxes	286,024	0	286,024
Regulatory fee	22,810	2,312	25,122
Deferred income tax	(26,513)	0	(26,513)
State income tax	50,650	44,393	95,043
Federal income tax	414,823	363,575	778,398
Total operating revenue deductions	14,231,071	410,280	14,641,351
Net operating income for a return	$3,315,263	$1,367,735	$4,682,998

SCHEDULE II-A
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Original Cost Rate Base
For the Twelve Months Ended March 31, 2019
CWSNC Water Operations

Item	Amount
Plant in service	$114,766,817
Accumulated depreciation	(29,553,703)
Net plant in service	85,213,114
Cash working capital	1,184,436
Contributions in aid of construction	(17,662,813)
Advances in aid of construction	(23,760)
Accumulated deferred income taxes	(2,312,807)
Customer deposits	(175,942)
Inventory	167,608
Gain on sale and flow back taxes	(281,868)
Plant acquisition adjustment	(2,085,004)
Excess book value	0
Cost-free capital	(121,791)
Average tax accruals	(81,595)
Regulatory liability for excess deferred taxes	(2,084,991)
Deferred charges	1,611,323
Pro forma plant	0
Original cost rate base	$63,345,909
Rates of return:	
Present	5.23%
Approved	7.39%

SCHEDULE III-A
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Statement of Capitalization and Related Costs
For the Twelve Months Ended March 31, 2019
CWSNC Water Operations

	Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
		PRESENT RATES		
Long-term Debt	50.90%	$32,243,068	5.36%	$1,728,228
Common Equity	49.10%	31,102,841	5.10%	1,587,035
Total	100.00%	$ 63,345,909		$3,315,263
		APPROVED RATES		
Long-term Debt	50.90%	$ 32,243,068	5.36%	$1,728,228
Common Equity	49.10%	31,102,841	9.50%	2,954,770
Total	100.00%	$ 63,345,909		$4,682,998

SCHEDULE I-B
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Net Operating Income for a Return
For the Twelve Months Ended March 31, 2019
CWSNC Sewer Operations

	Present Rates	Increase Approved	After Approved Increased
Operating Revenues:			
Service revenues	$12,961,929	$2,942,923	$15,904,852
Miscellaneous revenues	124,500	8,829	133,329
Uncollectibles	(98,511)	(22,366)	(120,877)
Total operating revenues	12,987,918	2,929,386	15,917,304
Operating Revenue Deductions:			
Salaries and wages – Maintenance	1,622,020	0	1,622,020
Purchased power	838,308	0	838,308
Purchased water and sewer	740,741	0	740,741
Maintenance and repair	1,940,932	0	1,940,932
Maintenance testing	308,671	0	308,671
Meter reading	0	0	0
Chemicals	318,617	0	318,617
Transportation	171,371	0	171,371
Operating expense charged to plant	(217,966)	0	(217,966)
Outside services – other	395,475	0	395,475
Salaries and wages – General	656,845	0	656,845
Office supplies & other office exp.	186,580	0	186,580
Regulatory commission expense	102,331	0	102,331
Pension and other benefits	524,372	0	524,372
Rent	107,979	0	107,979
Insurance	255,830	0	255,830
Office utilities	248,550	0	248,550
Miscellaneous	74,254	0	74,254
Depreciation expense	2,821,151	0	2,821,151
Amortization of CIAC	(570,054)	0	(570,054)
Amortization of PAA	(16,931)	0	(16,931)
Amortization of ITC	(251)	0	(251)
Franchise and other taxes	(2,595)	0	(2,595)
Property taxes	93,092	0	93,092
Payroll taxes	172,838	0	172,838
Regulatory fee	16,884	3,808	20,692
Deferred income tax	(33,406)	0	(33,406)
State income tax	14,845	73,140	87,985
Federal income tax	121,581	599,012	720,593
Total operating revenue deductions	10,892,064	675,960	11,568,024
Net operating income for a return	$2,095,854	$2,253,426	$4,349,280

SCHEDULE II-B
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Original Cost Rate Base
For the Twelve Months Ended March 31, 2019
CWSNC Sewer Operations

Item	Amount
Plant in service	$102,974,564
Accumulated depreciation	(23,646,093)
Net plant in service	79,328,471
Cash working capital	941,771
Contributions in aid of construction	(17,559,280)
Advances in aid of construction	(9,180)
Accumulated deferred income taxes	(2,884,203)
Customer deposits	(106,311)
Inventory	101,275
Gain on sale and flow back taxes	(135,943)
Plant acquisition adjustment	296,963
Excess book value	0
Cost-free capital	(139,708)
Average tax accruals	(49,923)
Regulatory liability for excess deferred taxes	(1,259,826)
Deferred charges	307,657
Pro forma plant	0
Original cost rate base	$58,831,763

Rates of return:

Present	3.56%
Approved	7.39%

SCHEDULE III-B
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Statement of Capitalization and Related Costs
For the Twelve Months Ended March 31, 2019
CWSNC Sewer Operations

	Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
		PRESENT RATES		
Long-term Debt	50.90%	$ 29,945,367	5.36%	$1,605,072
Common Equity	49.10%	28,886,396	1.70%	490,782
Total	100.00%	$ 58,831,763		$2,095,854
		APPROVED RATES		
Long-term Debt	50.90%	$ 29,945,367	5.36%	$1,605,072
Common Equity	49.10%	28,886,396	9.50%	2,744,208
Total	100.00%	$ 58,831,763		$4,349,280

SCHEDULE I-C
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Net Operating Income for a Return
For the Twelve Months Ended March 31, 2019
BF/FH/TC Water Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$1,304,521	$97,488	$1,402,009
Miscellaneous revenues	51,060	312	51,372
Uncollectibles	(16,567)	(1,239)	(17,806)
Total operating revenues	1,339,014	96,561	1,435,575
Operating Revenue Deductions:			
Salaries and wages – Maintenance	308,862	0	308,862
Purchased power	69,724	0	69,724
Purchased water and sewer	0	0	0
Maintenance and repair	63,151	0	63,151
Maintenance testing	8,314	0	8,314
Meter reading	30,753	0	30,753
Chemicals	44,189	0	44,189
Transportation	38,746	0	38,746
Operating expense charged to plant	(41,503)	0	(41,503)
Outside services – other	69,135	0	69,135
Salaries and wages – General	125,075	0	125,075
Office supplies & other office exp.	35,984	0	35,984
Regulatory commission expense	17,639	0	17,639
Pension and other benefits	99,850	0	99,850
Rent	21,337	0	21,337
Insurance	50,550	0	50,550
Office utilities	43,252	0	43,252
Miscellaneous	11,671	0	11,671
Depreciation expense	169,164	0	169,164
Amortization of CIAC	(56,417)	0	(56,417)
Amortization of PAA	13,303	0	13,303
Amortization of ITC	0	0	0
Franchise and other taxes	2,583	0	2,583
Property taxes	10,553	0	10,553
Payroll taxes	32,912	0	32,912
Regulatory fee	1,741	125	1,866
Deferred income tax	(923)	0	(923)
State income tax	2,145	2,411	4,556
Federal income tax	17,569	19,745	37,314
Total operating revenue deductions	1,189,358	22,281	1,211,639
Net operating income for a return	$149,656	$74,280	$223,936

SCHEDULE II-C
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Original Cost Rate Base
For the Twelve Months Ended March 31, 2019
BF/FH/TC Water Operations

Item	Amount
Plant in service	$6,285,688
Accumulated depreciation	2,083,262)
Net plant in service	4,202,426
Cash working capital	124,591
Contributions in aid of construction	(1,055,139)
Advances in aid of construction	0
Accumulated deferred income taxes	(84,226)
Customer deposits	(16,236)
Inventory	1,503
Gain on sale and flow back taxes	0
Plant acquisition adjustment	13,196
Excess book value	0
Cost-free capital	0
Average tax accruals	(5,624)
Regulatory liability for excess deferred taxes	(291,777)
Deferred charges	140,413
Pro forma plant	0
Original cost rate base	$3,029,127

Rates of return:	
Present	4.94%
Approved	7.39%

SCHEDULE III-C
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Statement of Capitalization and Related Costs
For the Twelve Months Ended March 31, 2019
BF/FH/TC Water Operations

	Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
		PRESENT RATES		
Long-term Debt	50.90%	$ 1,541,826	5.36%	$82,642
Common Equity	49.10%	1,487,301	4.51%	67,014
Total	100.00%	$ 3,029,127		$149,656
		APPROVED RATES		
Long-term Debt	50.90%	$ 1,541,826	5.36%	$82,642
Common Equity	49.10%	1,487,301	9.50%	141,294
Total	100.00%	$ 3,029,127		$223,936

SCHEDULE I-D
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Net Operating Income for a Return
For the Twelve Months Ended March 31, 2019
BF/FH Sewer Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$2,099,870	$143,157	$2,243,027
Miscellaneous revenues	22,114	458	22,572
Uncollectibles	(26,668)	(1,818)	(28,486)
Total operating revenues	2,095,316	141,797	2,237,113
Operating Revenue Deductions:			
Salaries and wages – Maintenance	334,600	0	334,600
Purchased power	146,154	0	146,154
Purchased water and sewer	0	0	0
Maintenance and repair	207,709	0	207,709
Maintenance testing	25,219	0	25,219
Meter reading	0	0	0
Chemicals	19,210	0	19,210
Transportation	40,468	0	40,468
Operating expense charged to plant	(44,961)	0	(44,961)
Outside services – other	72,182	0	72,182
Salaries and wages – General	135,498	0	135,498
Office supplies & other office expense	37,514	0	37,514
Regulatory commission expense	18,429	0	18,429
Pension and other benefits	108,171	0	108,171
Rent	22,286	0	22,286
Insurance	52,793	0	52,793
Office utilities	44,523	0	44,523
Miscellaneous	12,219	0	12,219
Depreciation expense	391,406	0	391,406
Amortization of CIAC	(146,182)	0	(146,182)
Amortization of PAA	42,674	0	42,674
Amortization of ITC	0	0	0
Franchise and other taxes	2,830	0	2,830
Property taxes	11,022	0	11,022
Payroll taxes	35,654	0	35,654
Regulatory fee	2,724	184	2,908
Deferred income tax	(8,286)	0	(8,286)
State income tax	7,834	3,540	11,374
Federal income tax	64,160	28,995	93,155
Total operating revenue deductions	1,635,850	32,719	1,668,569
Net operating income for a return	$459,466	$109,078	$568,544

SCHEDULE II-D
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Original Cost Rate Base
For the Twelve Months Ended March 31, 2019
BF/FH Sewer Operations

Item	Amount
Plant in service	$14,185,016
Accumulated depreciation	(2,614,885)
Net plant in service	11,570,131
Cash working capital	154,002
Contributions in aid of construction	(3,993,443)
Advances in aid of construction	0
Accumulated deferred income taxes	(714,208)
Customer deposits	(16,958)
Inventory	1,570
Gain on sale and flow back taxes	0
Plant acquisition adjustment	936,967
Excess book value	0
Cost-free capital	0
Average tax accruals	(6,056)
Regulatory liability for excess deferred taxes	(304,750)
Deferred charges	63,314
Pro forma plant	0
Original cost rate base	$7,690,568
Rates of return:	
Present	5.97%
Approved	7.39%

SCHEDULE III-D
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Statement of Capitalization and Related Costs
For the Twelve Months Ended March 31, 2019
BF/FH Sewer Operations

	Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
		PRESENT RATES		
Long-term Debt	50.90%	$ 3,914,499	5.36%	$209,817
Common Equity	49.10%	3,776,069	6.61%	249,649
Total	100.00%	$ 7,690,568		$ 459,466
		APPROVED RATES		
Long-term Debt	50.90%	$ 3,914,499	5.36%	$ 209,817
Common Equity	49.10%	3,776,069	9.50%	358,727
Total	100.00%	$ 7,690,568		$ 568,544

WATER AND SEWER – MISCELLANEOUS

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 61–63

Rate Design

The evidence supporting these findings of fact is found in the verified Application and the accompanying NCUC Form W-1, the Stipulation, and the testimony and exhibits of Public Staff witnesses Junis and Casselberry and CWSNC witness DeStefano.

The water rates proposed by CWSNC in its Application were based on a fixed-to- variable ratio of 52% fixed for the base facility charge and 48% variable for the usage charge. Sewer rates were based on a fixed-to-variable ratio of 80% fixed for the base facility charge and 20% variable for the usage charge.

As part of its Application and as a matter of rate design in this case CWSNC proposes to include in its Uniform Sewer Rate Division, customers in the CLMS service area. CWSNC has maintained the CLMS system rates steady for the last four general rate cases (Docket No. W-354, Subs 336, 344, 356, and 360) in order to allow the remainder of the Uniform Sewer Rate Division to move toward parity with the CLMS sewer rates.

Public Staff witness Junis testified that the Public Staff recommended a service revenue ratio of 45/55 (base facilities charge to usage charge) for Uniform Water and BF/FH/TC Water residential customers, which he stated was consistent with the Public Staff's previous recommendations in CWSNC rate cases and similar to the stated target of 40/60 in the most recent Aqua North Carolina, Inc. (Aqua) rate case, Docket No. W-218, Sub 497. Moreover, he stated the rate design ratio of 45/55 was incorporated in Public Staff witness Casselberry's testimony and exhibits detailing the billing analysis and proposed rates. Tr. vol. 8, 107, 155.

Public Staff witness Junis recommended a 65/35 ratio for Uniform Sewer residential customers, an incremental approach to the target of 45/55, which was also incorporated in witness Casselberry's billing analysis and proposed rates. Tr. vol. 8, 159. Further, the Public Staff recommended that CLMS should be fully incorporated into the Uniform Sewer Rate Division as requested by the Company and that the Public Staff's recommended rates for the Uniform Sewer Rate Division should apply to CLMS customers.

On December 2, 2019, the CLCA filed a Resolution with the Commission whereby it stated that the Association

- strongly opposes being singled out for higher rates than any other territory served by CWSNC, and requests that the Commission adopt a uniform rate schedule for all CWSNC wastewater treatment customers; and
- requests that the Commission move Corolla Light and Monteray Shores area to the uniform rate schedule after thoroughly investigating and analyzing the basis of the CWSNC request, allowing only an increase that is clearly justified.

During the expert witness hearing in response to a question from the Commission, CLCA indicated that it has no objection to the Stipulation. Tr. vol. 9, 200–01.

In the Stipulation, the Stipulating Parties agreed to a rate design for water utility service for its Uniform Water and BF/FH/TC Water residential customers to be based on a 50/50 ratio of base charge to usage charge, and to use an 80/20 ratio of base charge to usage charge for CWSNC's Uniform Sewer residential customers.[1]

Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate to utilize a 50/50 ratio of base charge to usage charge in this proceeding for CWSNC's Uniform Water and BF/FH/TC Water residential customers and an 80/20 ratio of base charge to usage charge for CWSNC's Uniform Sewer residential customers as agreed to by the Company and the Public Staff, embodied in the Stipulation, and not opposed by any party. Further, the Commission concludes that it is reasonable and appropriate to consolidate the CLMS sewer service rates with the Company's Uniform Sewer Division rates as requested by CWSNC and supported by both the Public Staff and the CLCA. The Commission concludes that such rate design is fair and reasonable to both CWSNC and its customers. Therefore, taking into account the forgoing findings and conclusions, the Commission concludes that the rates and charges included in Appendices A-1 and A-2, and the Schedules of Connection Fees for Uniform Water and Uniform Sewer, attached hereto as Appendices B-1 and B-2, are just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 64-65

Water and Sewer System Improvement Charges

The evidence supporting these findings of fact is found in the generic rulemaking proceeding, Docket No. W-100, Sub 54, wherein the Commission issued orders establishing procedures for implementing and applying the WSIC and SSIC mechanism; in CWSNC's 2013 rate case, Docket No. W-354, Sub 336, wherein the Commission initially approved the Company's WSIC and SSIC mechanism; and in the Commission's prior orders approving WSIC and SSIC mechanisms for CWSNC and the other Corix companies that have been merged into CWSNC.

The Commission's previously-approved WSIC and SSIC rate adjustment mechanism continues in effect, although as required by Commission Rules R7-39(k) and R10-26(k), it has been reset to zero in this rate case. The WSIC and 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 and SSIC surcharge is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC and SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this rate case proceeding.

Based on the service revenues set forth and approved in this Order, the maximum WSIC and SSIC charges as of the effective date of this Order are:

[1] BF/FH Sewer Rate Division has a monthly flat rate for residential customers.

Item	Service Revenues	Cap %	WSIC & SSIC Cap
CWSNC Uniform Water Operations	$19,271,785	X 5% =	$963,589
CWSNC Uniform Sewer Operations	$15,904,852	X 5% =	$795,243
BF/FH/TC Water Operations	$1,402,009	X 5% =	$70,100
BF/FH Sewer Operations	$2,243,027	X 5% =	$112,151

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 66-68

Recommendations of the Public Staff

The evidence for these findings of fact is found in the Company's NCUC Form W-1, the testimony of Public Staff witness Casselberry, and the testimony of Company witness DeStefano.

In her prefiled testimony, witness Casselberry stated,

> The Public Staff recommends that in the next general rate case, W-1, Item 26, be reconciled with the Company's bill data to ensure that the filing does not include double bills, that the Company accounts for multi-unit customers, and that other bills produced, such as final bills, late notices, re-bills, or other miscellaneous bills are not included in the W-1, Item 26 filing.

Tr. vol. 8, 91. The Company does not oppose this recommendation of the Public Staff.

In response to the Commission's question during the expert witness hearing regarding whether the Company will be able to provide the information requested by the Public Staff, witness DeStefano responded that, "[t]he Company expects to be able to provide the information requested." Tr. vol. 9, 197.

In its Application the Company requested to increase its reconnection fee from $27.00 to $42.00. Witness Casselberry stated in her testimony that the Public Staff did not oppose increasing the reconnection fee from $27.00 to $42.00.

In its Application the Company also proposed to increase the water connection charge from $500 to $1,080 and the sewer connection charge from $2,000 to $2,635 for Winston Pointe Subdivision, Phase IA. Witness Casselberry stated in her testimony that the Public Staff recommended a connection charge of $1,080 for water and $1,400 for sewer in Winston Pointe Subdivision, Phase IA, as the connection charge should reflect Johnston County's – where the Company purchases bulk water and sewer treatment for Winston Pointe Subdivision – current bulk capacity fee for water and sewer. Witness Casselberry stated that CWSNC indicated that it agreed with the Public Staff's recommendation. Tr. vol. 8, 94.

In light of the foregoing the Commission concludes that it is reasonable and appropriate for the Company to provide accurate bill data and ensure that accurate data is filed in its NCUC Form W-1, Item 26 in its next rate case filing. The Commission further concludes that the reconnection fee should be increased from \$27.00 to \$42.00, and that a connection charge of \$1,080 for water and \$1,400 for sewer in Winston Pointe Subdivision, Phase 1A, is reasonable and appropriate.

IT IS, THEREFORE, ORDERED as follows:

1. That the affidavit of CWSNC's Financial Planning and Analysis Manager, Matthew Schellinger, filed on January 10, 2020, and the Public Staff's Revised Settlement Exhibits I and II filed on January 13, 2020, in these dockets are hereby entered into evidence;

2. That all late-filed exhibits filed by CWSNC and the Public Staff in these dockets are hereby admitted into evidence. That the Resolution of Corolla Light Community Association, Inc., filed on December 2, 2019 is also admitted into evidence;

3. That the Partial Joint Settlement Agreement and Stipulation is incorporated herein by reference and is hereby approved in its entirety;

4. That the Partial Joint Settlement Agreement and Stipulation and the parts of this Order pertaining to the contents of that agreement shall not be cited or treated as precedent in future proceedings;

5. That CWSNC's request to defer incremental O&M costs related to Hurricane Florence storm impacts is approved as set forth in the Stipulation and stated herein, and that CWSNC's request to defer depreciation expense on its capital investments and lost revenues related to Hurricane Florence storm impacts is hereby denied;

6. That CWSNC's Petition to defer post-in-service costs associated with the two WWTPs is approved; provided, however, that the Company shall be, and hereby is, required to cease deferring said costs concurrent with the date the Company is authorized to begin reflecting the costs associated with the WWTPs in rates;

7. That CWSNC's Petition to defer post-in-service costs associated with the two AMR installation projects is denied;

8. That the Schedules of Rates, attached hereto as Appendices A-1 and A-2, 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;[1]

9. 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;

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[1] CWSNC's tariffs will be revised to reflect the change in taxability of CIAC based on the process outlined in Ordering Paragraph 4 of the Commission's February 11, 2020 Order, in Docket Nos. W-100, Sub 57 and W-100, Sub 62.

10. That CWSNC shall file the attached Certificate of Service, properly signed and notarized, not later than ten days after the Notices to Customers are mailed or hand delivered to customers;

11. That CWSNC's federal protected EDIT should continue to be flowed back in accordance with the RSGM pursuant to the Commission's Sub 360 Order;

12. That it is reasonable and appropriate for purposes of this proceeding for CWSNC to refund its remaining federal unprotected EDIT balances over 24 months instead of the remaining 35 months as originally ordered by the Commission in Sub 360;

13. That CWSNC's state EDIT recorded pursuant to the Commission's Sub 138 Order should continue to be amortized in accordance with the Commission's Sub 356 Order and as confirmed by the Commission in its Sub 360 Order;

14. That CWSNC shall receive estimates for the cost of a filtration system in Bradfield Farms Subdivision within 60 days of the date of this Order and shall share those estimates with the Bradfield Farms Homeowners Association;

15. That with respect to AMR meter installation projects planned for the future, CWSNC shall work with the Public Staff pursuant to N.C.G.S. § 62-133.12 and Commission Rule R7-39 to mitigate regulatory lag using WSIC recovery. The burden to prove CWSNC's investments recovered under the WSIC mechanism are reasonably and prudently incurred as required by N.C.G.S. § 62-133.12 and Commission Rule R7-39 shall remain with CWSNC;

16. That in the Company's next general rate case filing CWSNC shall ensure that its NCUC Form W-1, Item 26 is reconciled with the Company's bill data to ensure that the filing does not include double bills, that the Company accounts for multi-unit customers, and that other bills produced, such as final bills, late notices, re-bills, or other miscellaneous bills are not included in the NCUC Form W-1, Item 26 filing; and

17. That the Chief Clerk shall establish Docket No. W-354, Sub 364A as the single docket to be used for all future WSIC and SSIC filings, orders, and reporting requirements and shall close Docket No. W-354, Sub 360A.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of March, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

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 Fairfield Harbour Service Area, Treasure Cove, Register Place Estates, North Hills, Glen Arbor/North Bend, Bradfield Farms, Silverton, Woodland Farms, andLarkhaven 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	$ 28.92
1" meter	$ 72.30
1 1/2" meter	$ 144.60
2" meter	$ 231.36
3" meter	$ 433.80
4" meter	$ 723.00
6" meter	$1,446.00

Usage Charge:

A. Treated Water/1,000 gallons	$ 8.27
B. Untreated Water/1,000 gallons (Brandywine Bay Irrigation Water)	$ 4.23

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	$ 3.40
Riverbend	Town of Franklin	$ 7.50
Riverpointe	Charlotte Water	$ 6.48
Whispering Pines	Town of Southern Pines	$ 3.28
White Oak Plantation/ Lee Forest	Johnston County	$ 2.65
Winston Plantation	Johnston County	$ 2.65
Winston Point	Johnston County	$ 2.65
Woodrun	Montgomery County	$ 3.19
Yorktown	City of Winston Salem	$ 5.79
Zemosa Acres	City of Concord	$ 5.41
Carolina Trace	City of Sanford	$ 2.21

Commercial customers, including condominiums or other property ownerassociations 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 andusage associated with the meter.

When because of the method of water line installation utilized by the developer orowner, 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 plusthe 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 Service</u>: (Billed in Arrears) $ 58.54
<u>Availability Rate</u>: (Semiannual)

Applicable only to property owners in Carolina Forest and Woodrun Subdivisions in Montgomery County $ 27.15
<u>Availability Rate</u>: (Monthly)

Applicable only to property owners in Linville Ridge Subdivision $ 13.60

WATER AND SEWER – MISCELLANEOUS

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Sapphire Valley Service Area	$ 10.05

Availability Rate: (Monthly rate, billed quarterly))

Applicable only to property owners in Connestee Falls	$ 5.3
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	$ 42.00
If water service is discontinued at customer's request	$ 42.00

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)	$ 58.91
Commercial (based on meter size with zero usage)	
< 1" meter	$ 58.91
1" meter	$ 147.28
1 1/2" meter	$ 294.55
2" meter	$ 471.28
3" meter	$ 883.65
4" meter	$1,472.75
6" meter	$2,945.50

B. Usage charge, per 1,000 gallons $ 4.59

Commercial customers, including condominiums or other property ownerassociations who bill their members directly, shall have a separate account set upfor each meter and each meter shall be billed separately based on the size of themeter and usage associated with the meter.

Monthly Metered Purchased Sewer Service:

Collection Charge (Residential and Commercial) $ 41.24

Usage charge, per 1,000 gallons
(based on purchased water consumption)

Service Area	Bulk Provider	
White Oak Plantation/ Lee Forest/Winston Pt.	Johnston County	$ 5.57
Kings Grant	Two Rivers Utilities	$ 3.98
College Park	Town of Dallas	$ 7.33

Monthly Flat Rate Service: $ 73.73

Multi-residential customers who are served by a master meter shall be charged the flat rate per unit. $ 73.73

WATER AND SEWER – MISCELLANEOUS

Mt. Carmel Subdivision Service Area:

Monthly Base Facility Charge	$ 7.29
Monthly Collection Charge (Residential and Commercial)	$ 41.24
Usage Charge, per 1,000 gallons (based on metered water from the water supplier)	$ 6.32

Regalwood and White Oak Estates Subdivision Service Area:

Monthly Flat Rate Sewer Service	
Residential Service	$ 73.73
White Oak High School	$ 2,187.33
Child Castle Daycare	$ 280.41
Pantry	$ 153.76

Fairfield Mountain/Apple Valley (a.k.a. Rumbling Bald) Service Area, and Highland Shores Subdivision:

Monthly Sewer Rates:

Residential	
Collection charge/dwelling unit	$ 41.24
Treatment charge/dwelling unit	$ 69.50
Total monthly flat rate/dwelling unit	$ 110.74
Commercial and Other:	
Minimum monthly collection and treatment charge	$ 110.74
Monthly collection and treatment charge for customers who do not take water service	$ 110.74
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

WATER AND SEWER – MISCELLANEOUS

The Ridges at Mountain Harbour:

Monthly Sewer Rates:

Collection charge (Residential and Commercial)	$ 41.24
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	$ 10.20

Availability Rate: (Monthly rate, billed quarterly)

Applicable only to property owners in Connestee Falls	$ 5.75

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 – MISCELLANEOUS

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 Commissionin Docket No. W-354, Sub 364, on this the 31st day of March, 2020.

APPENDIX A-2
PAGE 1 OF 5

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, ANDWOODLAND 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	$ 17.30
1" meter	$ 43.25
1 1/2" meter	$ 86.50
2" meter	$138.40

Usage Charge, per 1,000 gallons $ 4.20

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Harbour Service Area $ 3.55

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 – MISCELLANEOUS

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 mainshave 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 caus	$ 42.00
If water service is discontinued at customer's request	$ 42.00
New Meter Charge:	Actual Cost
Irrigation Meter Installation:	Actual Cost

SEWER RATES AND CHARGES

Monthly Sewer Service:

Residential:

Flat Rate, per dwelling unit	$ 53.91
Bulk Flat Rate, per REU	$ 53.91

Commercial and Other:

Monthly Flat Rate (Customers who do not take water service)	$ 53.91

WATER AND SEWER – MISCELLANEOUS

Monthly Metered Rates
(based on meter size with zero usage)

<1" meter	$ 44.62
1" meter	$ 111.55
1 1/2" meter	$ 223.10
2" meter	$ 356.96

Usage Charge, per 1,000 gallons $ 2.25

Bulk Sewer Service for Hawthorne at the Green Apartments: [4/]

Bulk Flat Rate, per REU $ 53.91

(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 $ 2.85

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 mainshave 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 semiannuallyin advance.
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25days 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.

[4] Each Apartment building will be considered 92.42% occupied on an ongoing basis for billing purposes as sooa 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.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 364, on this the 31st day of March, 2020.

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
Saddlewood/Oak Hollow (Summey Bldrs.)	$ 0.00	$ 0.00

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PAGE 2 OF 3

Subdivision	CC	PMF
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	$1,080.00	$ 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.ka.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

APPENDIX B-1
PAGE 3 OF 3

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, Whisper Lake 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

[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 UtilitiesCommission in Docket No. W-354, Sub 364, on this the 31st day of March, 2020.

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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
White Oak Plantation	$ 0.00	$ 0.00
Willowbrook	$ 0.00	$ 0.00

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Willowbrook (Phase 3)	$ 0.00	$ 0.00
Winston pointe (Phase 1A)	$1,400.00	$ 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 ValleyPhases I and II

Recoupment of Capital Fee (RCF) [2/]	$ 0.00
Connection charge	$ 550.00

WATER AND SEWER – MISCELLANEOUS

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PAGE 3 OF 3

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

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 sucb 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 364, on this the 31st day of March, 2020.

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PAGE 1 OF 6

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-354, SUB 364

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	)	NOTICE TO CUSTOMERS
28217, for Authority to Adjust and Increase	)	
Rates for Water and Sewer Utility Service in	)	
All of its Service Areas in North Carolina	)	

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. The new approved rates are as follows:

WATER RATES AND CHARGES

(Excluding Fairfield Harbour Service Area and Treasure Cove, Register Place Estates, North Hills, Glen Arbor/North Bend, Bradfield Farms, Larkhaven, 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	$ 28.92
1" meter	$ 72.30
1 1/2" meter	$ 144.60
2" meter	$ 231.36
3" meter	$ 433.80
4" meter	$ 723.00
6" meter	$1,446.00

Usage Charge:

A.	Treated Water/1,000 gallons	$ 8.27
B.	Untreated Water/1,000 gallons (Brandywine Bay Irrigation Water)$	4.23

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	$	3.40
Riverbend	Town of Franklin	$	7.50
Riverpointe	Charlotte Water	$	6.48
Whispering Pines	Town of Southern Pines	$	3.28
White Oak Plantation/ Lee Forest	Johnston County	$	2.65
Winston Plantation	Johnston County	$	2.65
Winston Point	Johnston County	$	2.65
Woodrun	Montgomery County	$	3.19
Yorktown	City of Winston Salem	$	5.79
Zemosa Acres	City of Concord	$	5.41
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 Service: (Billed in Arrears) $ 58.54
Availability Rate: (Semiannual)

Applicable only to property owners in Carolina Forest and Woodrun Subdivisions in Montgomery County $ 27.15

Availability Rate: (Monthly)

Applicable only to property owners in Linville Ridge Subdivision $ 13.60

WATER AND SEWER – MISCELLANEOUS

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Sapphire Valley Service Area	$ 10.05

Availability Rate: (Monthly rate, billed quarterly)

Applicable only to property owners in Connestee Falls	$ 5.30

SEWER RATES AND CHARGES

(Excluding 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

Uniform Sewer Customers:

Monthly Metered Sewer Service:

Base Facility Charge:

Residential (zero usage)	$ 58.91
Commercial (based on meter size with zero usage)	
< 1" meter	$ 58.91
1" meter	$ 147.28
1 1/2" meter	$ 294.55
2" meter	$ 471.28
3" meter	$ 883.65
4" meter	$ 1,472.75
6" meter	$ 2,945.50

Usage charge, per 1,000 gallons $ 4.59

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)	$ 41.24

Usage charge, per 1,000 gallons based on purchased water consumption

WATER AND SEWER – MISCELLANEOUS

Service Area	Bulk Provider	
White Oak Plantation/ Lee Forest/Winston Pt.	Johnston County	$ 5.57
Kings Grant	Two Rivers Utilities	$ 3.98
College Park	Town of Dallas	$ 7.33

Monthly Flat Rate Service:	$ 73.73
Multi-residential customers who are served by a master meter shall be charged the flat rate per unit.	$ 73.73

Mt. Carmel Subdivision Service Area:

Monthly Base Facility Charge	$ 7.29
Monthly Collection Charge (Residential and commercial)	$ 41.24
Usage Charge/1,000 gallons based on purchased water	$ 6.32

Regalwood and White Oak Estates Subdivision Service Area:

Monthly Flat Rate Sewer Service	
Residential Service	$ 73.73
White Oak High School	$ 2,187.33
Child Castle Daycare	$ 280.41
Pantry	$ 153.76

Fairfield Mountain/Apple Valley (a.k.a. Rumbling Bald) Service Area, Highland Shores Subdivisions and Laurel Mountain Estates
Monthly Sewer Rates:

Residential:	
Collection charge/dwelling unit	$ 41.24
Treatment charge/dwelling unit	$ 69.50
Total monthly flat rate/dwelling unit	$ 110.74
Commercial and Other:	
Minimum monthly collection and treatment charge	$ 110.74
Monthly collection and treatment charge for customers Who do not take water service (per single family unit)	$ 110.74

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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:

Collection charge (Residential and Commercial)	$ 41.24
Treatment Charge (Residential and Commercial)	
< 1 inch meter	$ 18.42
2 inch meter	$ 147.36

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Sapphire Valley Service Area $ 10.20

Availability Rate: (Monthly rate, billed quarterly)

Applicable only to property owners in Connestee Falls $ 5.75

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 364 rate case, but CWSNC may, under the Rules and Regulations of the Commission, next apply for a rate surcharge on July 31, 2020 to become effective October 1, 2020. 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 360A" and "W-354, Sub 364A" .

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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.

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 shall continue to flow back the federal protected EDIT to customers in accordance with the Reverse South Georgia Method as ordered by the Commission in CWSNC's last rate case (Docket No. W-354, Sub 360), and (2) CWSNC shall refund the remaining federal unprotected EDIT to customers through a levelized rider over a period of 24 months as requested by CWSNC instead of the remaining 35-month period as originally ordered by the Commission in Docket No. W-354, Sub 360.

CWSNC will provide the applicable dollar amount concerning the federal EDIT rider (refund) shown as a separate line item on individual customers' monthly bills, along with explanatory information.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of March, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

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PAGE 1 OF 3

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-354, SUB 364

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	)))))))))))	NOTICE TO CUSTOMERS IN TREASURE COVE, REGISTER PLACE ESTATES, NORTH HILLS, AND GLEN ARBOR/NORTH BEND SUBDIVISIONS, FAIRFIELD HARBOUR SERVICE AREA, BRADFIELD FARMS, LARKHAVEN, SILVERTON, AND WOODLAND FARMS SUBDIVISIONS, AND HAWTHORNE AT THE GREEN APARTMENTS

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Carolina Water Service, Inc. of North Carolina 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, 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	\$ 17.30
1" meter	\$ 43.25
1 1/2" meter	\$ 86.50
2" meter	\$138.40
Usage Charge, per 1,000 gallons	\$ 4.20

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Harbour Service Area	\$ 3.55

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PAGE 2 OF 3

SEWER RATES AND CHARGES

Monthly Sewer Service:

Residential:

Flat Rate, per dwelling unit	$ 53.91
Bulk Flat Rate, per REU	$ 53.91

Commercial and Other:

Monthly Flat Rate (Customers who do not take water service)	$ 53.91
Monthly Metered Rates (based on meter size with zero usage)	
<1" meter	$ 44.62
1" meter	$111.55
1 1/2" meter	$223.10
2" meter	$356.96
Usage Charge, per 1,000 gallons	$ 2.25

Bulk Sewer Service for Hawthorne at the Green Apartments:

Bulk Flat Rate, per REU	$ 53.91

(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	$ 2.85

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 364 rate case, but CWSNC may, under the Rules and Regulations of the Commission, next apply for a rate surcharge on July 31, 2020, to become effective October 1, 2020. 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 360A" and "W-354 Sub 364A".

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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 shall continue to flow back the federal protected EDIT to customers in accordance with the Reverse South Georgia Method as ordered by the Commission in CWSNC's last rate case (Docket No. W-354, Sub 360), and (2) CWSNC shall refund the remaining federal unprotected EDIT to customers through a levelized rider over a period of 24 months as requested by CWSNC instead of the remaining 35-month period as originally ordered by the Commission in Docket No. W-354, Sub 360.

CWSNC will provide the applicable dollar amount concerning the federal EDIT rider (refund) shown as a separate line item on individual customers' monthly bills, along with explanatory information.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of March, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

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, Subs 363, 364, and 365, and the Notices were mailed or hand delivered by the date specified in the Order.

This the ______ day of __________________________________, 2020.

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, Subs 363, 364, and 365.

Witness my hand and notarial seal, this the ______ day of ____________________, 2020.

____
Notary Public

____
Printed or Typed Name

(SEAL) My Commission Expires: _______________________________________
Date

ONE-HUNDRED TENTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

Volume III

ISSUED FROM
JANUARY 1, 2020 THROUGH DECEMBER 31, 2020

ONE-HUNDRED TENTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2020, through December 31, 2020

Charlotte A. Mitchell, Chair

ToNola D. Brown-Bland, Commissioner

Lyons Gray, Commissioner

Daniel G. Clodfelter, Commissioner

Kimberly W. Duffley, Commissioner

Jeffrey A. Hughes, Commissioner

Floyd B. McKissick, Jr., 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.

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WATER AND SEWER – RATE INCREASE

DOCKET NO. W-218, SUB 526

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 DENYING REVENUE DEFERRAL MECHANISM, APPROVING FINANCIAL UNDERTAKING AND CUSTOMER NOTICE

BY THE COMMISSION: On December 31, 2019, Aqua North Carolina, Inc. (Aqua or Company), filed an application with the Commission seeking authority to adjust and increase its rates for providing water and sewer utility service in all of its service areas in North Carolina (Application). Within its Application, Aqua notified the Commission of its intent to partially implement its proposed rates on a temporary, interim basis subject to refund, pursuant to N.C. Gen. Stat. § 62-135, effective for service rendered on and after six months from January 30, 2020, or July 30, 2020.

On January 21, 2020, the Commission issued an order declaring this proceeding a general rate case and suspending rates.

On February 14, 2020, the Commission issued an order scheduling hearings, establishing discovery guidelines, establishing deadlines for filing direct and rebuttal testimony and exhibits, and requiring customer notice (Scheduling Order). In the Scheduling Order the Commission approved and required mailing or hand delivery of the Notice to Customers which included notice of Aqua's intent to implement its proposed rates under bond on a temporary, interim basis subject to refund, effective for service rendered on and after six months from January 30, 2020, or July 30, 2020.

On March 19, 2020, in Docket No. M-100, Sub 158, the Commission issued its Order Suspending Utility Disconnections for Non-Payment, Allowing Reconnection, and Waiving Certain Fees (March 19, 2020 Order) providing that, until the end of the State of Emergency declared by Governor Cooper on March 10, 2020, due to the COVID-19 pandemic, or until further order of the Commission, public utilities, including water and wastewater utilities, must cease customer disconnections due to non-payment of utility bills, with limited exceptions, and waive the application of late fees incurred during the State of Emergency.

The participation of the Public Staff – North Carolina Utilities Commission (Public Staff) in this proceeding is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e). On April 29, 2020, the North Carolina Attorney General's Office (AGO) filed a notice of intervention in this docket pursuant to N.C. Gen. Stat. § 62-20.

On June 11, 2020, Aqua filed a petition requesting that the Commission issue an order allowing deferral of revenues in lieu of rates under bond or, in the alternative, approving customer notice of its intent to place temporary rates in effect subject to an undertaking to refund in three of its five Rate Divisions pursuant to N.C. Gen. Stat. § 62-135. (Petition) According to Aqua's Petition and proposed Customer Notice, the rates and charges to become effective on a temporary basis reflect an increase of approximately $4.5 million for three of its five Rate Divisions. In its Petition, Aqua presents two alternative requests to the Commission for its consideration with respect to the manner of rate recovery in this case during the interim period from July 30, 2020 (when rates under bond could be implemented by the Company) and the date of the final order in this case.

Aqua's Petition is a request to create a regulatory asset to capture revenue that the Company would otherwise collect if it were to put temporary rates into effect under bond. The deferred revenue would be recovered via a surcharge to be collected from customers over a reasonable period of time effective on and after the issuance of a final order in this general rate case. Aqua contends that in light of the unusual and unique circumstances raised by the pandemic, the revenue deferral mechanism option offers the benefits of certainty at the time of later imposition of the rate change, delay of changes in rates to a later point in time by when it is hoped that the economy and the nation's health will be improved, avoidance of a two-step rate increase process and the attendant confusion and possibility of refunds with interest, and a reasonable opportunity for the Company to avoid a significant, unrecoverable revenue loss between July 30 and the date of the Commission's final order in this case.

Aqua's alternative request should the Commission deny its Petition for deferral is a request for approval of its Customer Notices and Undertaking to Refund, which it attached to its Petition as Appendices A, B, and C, respectively. In summary, Aqua makes an alternative request that the Commission take action it deems necessary to enable Aqua to implement temporary rates in three of its five Rate Divisions as authorized under N.C.G.S. § 62-135 effective for service rendered on and after July 30, 2020, should the deferral Petition be denied.

On June 16, 2020, the Public Staff and the AGO filed a joint response requesting that the Commission deny Aqua's Petition for approval of an order allowing deferral of revenues in lieu of rates under bond. The Public Staff and the AGO argue that there is no statutory basis for the revenue deferral mechanism and that N.C.G.S. § 62-135 provides a remedy to address any financial hardship perceived by Aqua. The Public Staff and the AGO also argue that such a revenue deferral mechanism would both "violate the fundamental principle of utility ratemaking that customers be provided notice and a description of forthcoming rates changes," and "would constitute unlawful, retroactive ratemaking." Finally, the Public Staff and the AGO disagree with Aqua's assertion that its proposed deferred revenue mechanism is a more beneficial alternative for ratepayers than implementing temporary rates under bond.

Further, the Public Staff and the AGO note that while Aqua concedes that there is no precedent for the deferred revenue mechanism, Aqua nevertheless fails to cite any legal authority in support of its request and provides no financial information or a request for an accounting order — integral parts of a deferral request — in support of its Petition. The Public Staff and the AGO maintain that the legislative option to implement rates under bond pursuant to N.C.G.S. § 62-135 provides safeguards for ratepayers and procedural steps for implementing rates under bond whereas the revenue deferral mechanism provides at best "illusory and, therefore, wholly inadequate" customer notice and does not require the filing of a bond or undertaking associated with the rate change and the requirement of a refund, with interest for any temporary rates later determined to be excessive.

Based on the foregoing and the entire record herein, the Commission does not find good cause to expand consideration of the use of deferral accounting, a tool the Commission uses sparingly as an exception to the general rule of cost recovery, outside the historical parameters presented in Commission decisions to date. Because the legislature has provided a mechanism for utilities to temporarily adjust rates during the pendency of a general rate case pursuant to N.C.G.S. § 62-135, the Commission is not persuaded that the use of an alternate method is prudent or in the public interest. Consequently, Aqua's request for authority to use a revenue deferral mechanism is denied.

While N.C.G.S. § 62-135 affords the Company a remedy to address any financial hardship it perceives during the pendency of a general rate case proceeding, the choice to exercise the remedy belongs to the Company and is not determined by the Commission. However, the Commission finds that Aqua in fact has satisfied the statutory requirements necessary to place new rates into effect, on a partial, temporary basis and subject to refund with interest at a rate of 10% per annum, effective July 30, 2020. The Commission, therefore, finds good cause to approve the Notices to Customers attached to this Order as Appendix A and B and Aqua's Undertaking to Refund. In approving the Notices to Customers, the Commission takes no position on whether the Company should or should not invoke the rates under bond mechanism authorized by statute and notes that the decision of whether to implement rates under bond lies solely with Aqua.

IT IS, THEREFORE, ORDERED as follows:

1. That Aqua's request to use a revenue deferral mechanism in lieu of rates under bond is hereby denied;

2. That the Commission takes no position on whether the Company should or should not invoke the rates under bond mechanism authorized by statute;

3. That the Notices to Customers regarding Aqua's request pursuant to N.C.G.S. § 62-135 to place an increase in its rates and charges into effect in accordance with the schedules attached hereto as Appendices A and B be, and the same are hereby approved;

4. That should Aqua decide to implement rates under bond, the applicable Notices to Customers attached as Appendices A and B shall be mailed with sufficient postage or hand delivered by Aqua to the respective customers no later than 20 days after the date of this Order; and that Aqua shall submit to the Commission the attached Certificate of Service properly signed and notarized no later than 30 days after the date of this Order;

5. That no rate or rates placed into effect pursuant to this notice shall result in an increase in more than 20% on any singe rate classification of the Company;

6. That Aqua shall be, and is hereby, obligated to refund to its customers any amount of temporary rates made effective on or after July 30, 2020, that are finally determined by the

Commission to be excessive, plus 10% interest per annum, and to make any refunds in a manner consistent with any additional terms and conditions imposed by the Commission in subsequent orders; and

7. That Aqua's undertaking to refund with interest, from the date that such rates are put into effect, any revenues in excess of those the Commission ultimately determines to be appropriate, attached hereto as Appendix C, be, and the same is hereby approved.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of June, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 526

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina,	)	NOTICE TO CUSTOMERS OF
Inc., 202 MacKenan Court, Cary,	)	TEMPORARY RATES EFFECTIVE
North Carolina 27511, for Authority to	)	ON JULY 30, 2020, SUBJECT TO
Adjust and Increase Rates for Water	)	UNDERTAKING
and Sewer Utility Service in All Its	)	TO REFUND
Service Areas in North Carolina	)	
	)	

<u>TEMPORARY RATES SUBJECT TO UNDERTAKING TO REFUND</u>

NOTICE IS HEREBY GIVEN THAT Aqua North Carolina, Inc. (Aqua or Company), is authorized to increase its rates and charges effective July 30, 2020, on a temporary basis, subject to refund, pursuant to N.C. Gen. Stat. § 62-135. The July 30, 2020 rate changes are not final rates and remain subject to the North Carolina Utilities Commission's (Commission's) final determination of the just and reasonable rates to be charged by Aqua on a permanent basis pursuant to Aqua's pending general rate case application in Docket No. W-218, Sub 526.

Aqua's choice to implement temporary rates under bond effective for water and sewer utility service rendered on and after July 30,2020, as allowed pursuant to N.C.G.S. § 62-135 is determined by the Company and is not a decision by the Commission. However, the Commission finds that Aqua in fact has satisfied the statutory requirements necessary to place new rates into effect, on a partial, temporary basis and subject to refund with interest at a rate of 10% per annum, effective July 30, 2020. In approving this Notice to Customers, the Commission takes no position on whether the Company should or should not invoke the temporary rates under bond authorized by statute and notes that the decision of whether to implement temporary rates under bond lies solely with Aqua.

On December 31, 2019, Aqua filed a rate case application with the Commission seeking authority to adjust and increase its rates for providing water and sewer utility service in all of its service areas in North Carolina effective for service rendered on and after January 30, 2020.

In its rate case application, Aqua notified the Commission that, pursuant to the provisions of N.C.G.S. § 62-135, the Company intended to implement its proposed rates

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on a temporary, interim basis subject to refund, effective for service rendered on and after six months from January 30, 2020, assuming that the Commission: (a) suspended the operation of the Company's proposed rates as requested in the rate case application; and (b) had not entered a final order by that date. Consistent with the customer notice provisions of N.C.G.S. § 62-135(a), Aqua further requested that the Notices to Customers attached to the Commission's order scheduling hearings should include a specific provision which notified customers that the Company intended to implement temporary rates under bond effective for service rendered on and after six months from January 30, 2020.

In the Commission's Order Scheduling Hearings, Establishing Discovery Guidelines, and Requiring Customer Notice issued on February 14, 2020, in Docket No. W-218, Sub 526, the Commission required the Company to send notices to customers which contained notification of the dates, times, and locations of the public hearings scheduled in this case and, at Aqua's request, customers were also notified of the Company's intent to implement temporary rates under bond effective for water and sewer utility service rendered on and after July 30,2020. The Notice to Customers stated that if ultimately found to be excessive by the Commission, these temporary rates are subject to refund to customers with interest at an interest rate to be ordered by the Commission. Thus, the present Notices to Customers is a second notice regarding the temporary rates which Aqua will place in effect on or after July 30, 2020, as specifically allowed by N.C.G.S. § 62-135.

Aqua's temporary rates for all its service areas, with the exception of the Brookwood and LaGrange service areas in Cumberland and Hoke Counties and the Fairways and Beau Rivage (The Cape) service areas in New Hanover County, are as follows:

WATER AND SEWER – RATE INCREASE

WATER UTILITY SERVICE

Monthly Metered Service (Residential and Commercial customers) Base facility charge (zero usage, based on meter size)	Existing Rates	Temporary Rates
<1" meter	$ 19.25	$ 21.04
1" meter	$ 48.13	$ 52.60
1-1/2" meter	$ 96.25	$ 105.20
2" meter	$ 154.00	$ 168.32
3" meter	$ 288.75	$ 315.60
4" meter	$ 481.25	$ 526.00
6" meter	$ 962.50	$1,052.00

The base charges listed above apply to all Aqua North Carolina metered water systems except those in the Brookwood/LaGrange service areas in Cumberland and Hoke Counties and the Fairways/Beau Rivage (The Cape) service areas in New Hanover County.

Usage charge, per 1,000 gallons	Existing Rates	Temporary Rates
All service areas unless noted differently below	$ 5.83	$ 6.49

Bulk Purchased Water Systems
Temporary base monthly charge same as above
Temporary usage charge per 1,000 gallons based on bulk water provider are unchanged.

Monthly Unmetered Service (flat rate)	Existing Rates	Temporary Rates
All service areas unless noted differently below		
Residential customers	$ 39.66	$ 47.00
Commercial customers (per REU)	$ 67.42	$ 74.87
(REU = Residential Equivalent Unit)		

Water System Improvement Charge	Existing Rates	Temporary Rates
All service areas unless noted differently	2.69%	0.00%

The Water System Improvement Charge is applied to the total water utility bill of each customer under the Company's applicable rates and charges.

WATER AND SEWER – RATE INCREASE

SEWER UTILITY SERVICE

Monthly Unmetered Service (flat rate)	Existing Rates	Temporary Rates
All service areas unless noted differently below		
Residential customers	$ 72.04	$ 77.49
Commercial customers (per REU)	$ 100.86	$ 106.94
(REU = Residential Equivalent Unit)		

Commercial Monthly Metered Service and all Parkway Crossing and Park South Station Service Areas (based on metered water usage)

Base facility charge (zero usage, based on water meter size)
All service areas unless noted differently below

	Existing Rates	Temporary Rates
<1" meter	$ 26.11	$ 26.59
1" meter	$ 65.28	$ 66.48
1-1/2" meter	$ 130.55	$ 132.95
2" meter	$ 208.88	$ 212.72
3" meter	$ 391.65	$ 398.85
4" meter	$ 652.75	$ 664.75
6" meter	$1,305.50	$1,329.50

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Usage charge, per 1,000 gallons	$ 8.92	$10.18
All service areas unless noted differently below		

Parkway Crossing and Park South Station Service Areas	Existing Rates	Temporary Rates
Base facility charge (zero usage)	As shown above	As shown above
Usage charge, per 1,000 gallons	$ 6.45	$ 6.45

WATER AND SEWER – RATE INCREASE

Hawthorne at the Greene Apartments, Woodland Farm Rocky Ridge and Beaver Farms Service Areas – Mecklenburg County:

	Existing Rates	Temporary Rates
Base facility charge (to be collected and delivered to Carolina Water Service, Inc. of North Carolina for treatment of the wastewater), per month (per REU)	$ 47.94	$ 47.94
Usage charge, per 1,000 gallons	$ 6.11	$ 7.26

Sewer System Improvement Charge	Existing Rates	Temporary Rates
All service areas unless noted differently	1.15%	0.00%

The Public Staff – North Carolina Utilities Commission (Public Staff) is authorized by statute to represent consumers in proceedings before the Commission. Written statements to the Public Staff should include the name of the subdivision where the customer is receiving service, contact information, and any information that the writer wishes to be considered by the Public Staff in its investigation of the matter; these statements should be addressed to Mr. Christopher J. Ayers, Executive Director, Public Staff, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300. Written statements may also be faxed to 919-715-6704 or e-mailed to statements@ncuc.net.

The Attorney General is also authorized by statute to represent consumers in proceedings before the Commission. Statements to the Attorney General should be addressed to The Honorable Josh Stein, Attorney General, 9001 Mail Service Center, Raleigh, North Carolina 27699-9001. They may also be e-mailed to utilityAGO@ncdoj.gov.

Information regarding this proceeding can be accessed from the Commission's website at www.ncuc.net under the docket number of this proceeding (i.e., W-218 Sub 526).

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TEMPORARY MORATORIUM ON DISCONNECTION FOR NONPAYMENT AND PROVISIONS FOR PAYMENT ARRANGEMENTS

In response to the COVID-19 public health crisis and to Governor Roy Cooper's Declaration of a State of Emergency (Executive Order No.116, March 10, 2020), the North Carolina Utilities Commission issued an Order on March 19, 2020 in Docket No. M-100, Sub 158 which addressed disconnections for nonpayment, reconnections, waivers of certain fees, interest, and payment arrangements. As early as March 13, 2020, Aqua North Carolina initiated actions consistent with the ultimate Commission Order and the Company joins other regulated utilities in strict compliance with the customer protection provisions set forth by the Commission. A complete copy of the Order may be found on the Commission website home page - https://www.ncuc.net.

The Commission also provided that, at the end of the State of Emergency, customers having arrearages accrued during the emergency period shall be provided the opportunity to make a reasonable payment arrangement over no less than a six month period and shall not be charged any late fees for late payment for arrearages accrued during the State of Emergency. (The Order does not relieve a customer of their obligation to pay bills for receipt of any utility service covered by the Order).

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of June, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 526

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	NOTICE TO CUSTOMERS OF
202 MacKenan Court, Cary, North Carolina	)	TEMPORARY RATE INCREASE
27511, for Authority to Adjust and Increase Rates	)	EFFECTIVE ON JULY 30, 2020,
for Water and Sewer Utility Service in All Its	)	SUBJECT TO UNDERTAKING
Service Areas in North Carolina	)	TO REFUND

TEMPORARY RATES SUBJECT TO UNDERTAKING TO REFUND

NOTICE IS HEREBY GIVEN THAT Aqua North Carolina, Inc. (Aqua or Company), is authorized to increase its rates and charges effective July 30, 2020, on a temporary basis, subject to refund, pursuant to N.C. Gen. Stat. § 62-135. The July 30, 2020 rate changes are not final rates and remain subject to the North Carolina Utilities Commission's (Commission's) final determination of the just and reasonable rates to be charged by Aqua on a permanent basis pursuant to Aqua's pending general rate case application in Docket No. W-218, Sub 526.

Aqua's choice to implement temporary rates under bond effective for water and sewer utility service rendered on and after July 30,2020, as allowed pursuant to N.C.G.S. § 62-135 is determined by the Company and is not a decision by the Commission. However, the Commission finds that Aqua in fact has satisfied the statutory requirements necessary to place new rates into effect, on a partial, temporary basis and subject to refund with interest at a rate of 10% per annum, effective July 30, 2020. In approving this Notice to Customers, the Commission takes no position on whether the Company should or should not invoke the temporary rates under bond authorized by statute and notes that the decision of whether to implement temporary rates under bond lies solely with Aqua.

On December 31, 2019, Aqua filed a rate case application with the North Carolina Utilities Commission seeking authority to adjust and increase its rates for providing water and sewer utility service in all of its service areas in North Carolina effective for service rendered on and after January 30, 2020.

In its rate case application, Aqua notified the Commission that, pursuant to the provisions of N.C.G.S. § 62-135, the Company intended to implement its proposed rates on a temporary, interim basis subject to refund, effective for service rendered on and after six months from January 30, 2020, assuming that the Commission: (a) suspended the operation of the Company's proposed rates as requested in the Application; and (b) had not entered a final order by that date. Consistent with the customer notice provisions of

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N.C.G.S. 62-135(a), Aqua further requested that the Notices to Customers attached to the Commission's order scheduling hearings should include a specific provision which notified customers that the Company intended to implement temporary rates under bond effective for service rendered on and after six months from January 30, 2020.

In the Commission's Order Scheduling Hearings, Establishing Discovery Guidelines, and Requiring Customer Notice issued on February 14, 2020, in Docket No. W-218, Sub 526, the Commission required the Company to send Notices to Customers which contained notification of the dates, times, and locations of the public hearings scheduled in this case and, at Aqua's request, customers were also notified of the Company's intent to implement temporary rates under bond effective for water and sewer utility service rendered on and after July 30, 2020. The Notices to Customers stated that if ultimately found to be excessive by the Commission, these temporary rates are subject to refund to customers with interest at an interest rate to be ordered by the Commission. Thus, the present Notices to Customers is a second notice regarding the temporary rates which Aqua will place in effect on or after July 30, 2020, as specifically allowed by N.C.G.S. § 62-135.

Aqua's temporary water rates for its Brookwood/LaGrange service areas in Cumberland and Hoke Counties are as follows:

WATER AND SEWER – RATE INCREASE

WATER UTILITY SERVICE

Monthly Metered Service (Residential and Commercial customers) Base charge, per month (zero usage, based on meter size)	Existing Rates	Temporary Rates
<1" meter	$ 14.03	$ 16.19
1" meter	$ 35.08	$ 40.48
1-1/2" meter	$ 70.15	$ 80.95
2" meter	$ 112.24	$ 129.52
3" meter	$ 210.45	$ 242.85
4" meter	$ 350.75	$ 404.75
6" meter	$ 701.50	$ 809.50

	Existing Rates	Temporary Rates
Usage charge, per 1,000 gallons All service areas unless noted differently below	$ 3.76	$ 4.62

Bulk Purchased Water Systems
Temporary base monthly charge same as above
Temporary usage charge, per 1,000 gallons based on bulk water provider are unchanged

Monthly Unmetered Service (flat rate)	Existing Rates	Temporary Rates
All service areas unless noted differently		
Residential customers	$ 33.17	$ 37.65
Commercial customers (per REU)	$ 56.39	$ 56.69
(REU = Residential Equivalent Unit)		

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Water System Improvement Charge	Existing Rate	Temporary Rate
All service areas unless noted differently	3.57%	0.00%

The Water System Improvement Charge is applied to the total water utility bill of each customer under the Company's applicable rates and charges.

WATER AND SEWER – RATE INCREASE

The Public Staff – North Carolina Utilities Commission (Public Staff) is authorized by statute to represent consumers in proceedings before the Commission. Written statements to the Public Staff should include the name of the subdivision where the customer is receiving service, contact information, and any information that the writer wishes to be considered by the Public Staff in its investigation of the matter; these statements should be addressed to Mr. Christopher J. Ayers, Executive Director, Public Staff, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300. Written statements may also be faxed to 919-715-6704 or e-mailed to statements@ncuc.net.

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TEMPORARY MORATORIUM ON DISCONNECTION FOR NONPAYMENT AND PROVISIONS FOR PAYMENT ARRANGEMENTS

In response to the COVID-19 public health crisis and to Governor Roy Cooper's Declaration of a State of Emergency (Executive Order No.116, March 10, 2020), the North Carolina Utilities Commission issued an Order on March 19, 2020 in Docket No. M-100, Sub 158 which addressed disconnections for nonpayment, reconnections, waivers of certain fees, interest, and payment arrangements. As early as March 13, 2020, Aqua North Carolina initiated actions consistent with the ultimate Commission Order and the Company joins other regulated utilities in strict compliance with the customer protection provisions set forth by the Commission. A complete copy of the Order may be found on the Commission website home page - https://www.ncuc.net.

The Commission also provided that, at the end of the State of Emergency, customers having arrearages accrued during the emergency period shall be provided the opportunity to make a reasonable payment arrangement over no less than a six month period and shall not be charged any late fees for late payment for arrearages accrued during the State of Emergency. (The Order does not relieve a customer of their obligation to pay bills for receipt of any utility service covered by the Order).

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of June, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX C

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 526

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	
202 MacKenan Court, Cary, North Carolina	)	UNDERTAKING TO REFUND OF
27511, for Authority to Adjust and Increase	)	AQUA NORTH CAROLINA, INC.
Rates for Water and Sewer Utility Service in	)	
All Its Service Areas in North Carolina	)	

NOW COMES AQUA NORTH CAROLINA, INC. (Aqua or Company) and files this Undertaking to Refund pursuant to N.C. Gen. Stat. § 62-135(c).

UNDERTAKING TO REFUND

Aqua North Carolina, Inc., by and through the undersigned Company President, makes this written undertaking to the North Carolina Utilities Commission that the Company will refund to its customers in its Aqua Water, Aqua Sewer, and Brookwood Water Rate Divisions using the current rate structure for any amount of temporary rates made effective on and after July 30, 2020, pursuant to N.C.G.S. 62-135, plus 10% interest per annum, as specified by the Commission pursuant to N.C.G.S. 62-130(e), as may finally be determined by the Commission to be excessive and as required by the Final Rate Case Order in this docket. Such refunds will be made consistent with any terms and conditions set forth by the Commission in its Final Rate Case Order.

This the ________ day of June, 2020.

____
Shannon V. Becker, President
Aqua North Carolina, Inc.

Sworn to and subscribed before me this the
__________day of June, 2020.

____
Notary Public
My Commission Expires: ____________________

WATER AND SEWER – RATE INCREASE

DOCKET NO. W-218, SUB 526

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 North Carolina	))))))	ORDER APPROVING PARTIAL SETTLEMENT AGREEMENT AND STIPULATION, DECIDING CONTESTED ISSUES, GRANTING PARTIAL RATE INCREASE, AND REQUIRING CUSTOMER NOTICE

HEARD: Tuesday, June 23, 2020, at 9:30 a.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Wednesday, July 8, 2020, at 1:30 p.m., and continuing as required through Monday, July 13, 2020, by virtual means using the Webex electronic platform

Monday, August 3, 2020, at 1:30 p.m., by virtual means using the Webex electronic platform

Monday, August 3, 2020, at 6:30 p.m., by virtual means using the Webex electronic platform

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

APPEARANCES:

For Aqua North Carolina, Inc.:

Jo Anne Sanford, Sanford Law Office, PLLC, Post Office Box 28085, Raleigh, North Carolina 27611-8085

Robert H. Bennink, Jr., Bennink Law Office, 130 Murphy Drive, Cary, North Carolina 27513

For the Using and Consuming Public:

Megan Jost, William E. Grantmyre, and William Creech, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

WATER AND SEWER – RATE INCREASE

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

BY THE COMMISSION: On November 26, 2019, pursuant to Commission Rule R1-17(a), Aqua North Carolina, Inc. (Aqua NC or the Company) filed a letter notifying the North Carolina Utilities Commission (Commission or NCUC) of its intent to file an application for a general rate case. On December 31, 2019, Aqua NC filed an Application to Increase Rates and Charges (Application or Rate Case Application) with the Commission requesting authority to adjust and increase its rates for water and sewer utility services in all its service areas in North Carolina, effective for service rendered on and after January 30, 2020. Included with this filing was certain information and data required by NCUC Form W-1, and the testimony and exhibits of witnesses Shannon Becker, Amanda Berger, Dylan D'Ascendis, and Edward Thill, and Direct Testimony of Joseph Pearce and Dean Gearhart.

The Commission issued its Order Establishing General Rate Case and Suspending Rates on January 21, 2020. The order declared the matter to be a general rate case, suspended the Company's proposed rates for up to 270 days, and established the test year period as the 12 months ending September 30, 2019. On February 14, 2020, the Commission issued its Order Scheduling Hearings, Establishing Discovery Guidelines, and Requiring Customer Notice (Scheduling Order). Among other things, the Scheduling Order established the dates, times, and locations for six public witness hearings to take place in April 2020 and an expert witness hearing to begin on June 23, 2020.

On March 2, 2020, Aqua NC filed its Ongoing Three-Year Water and Sewer System Improvement Charge (WSIC/SSIC) Plan in Docket No. W-218, Sub 497A.

On March 31, 2020, to assist in preventing the spread of coronavirus and in response to Governor Roy Cooper's Executive Order No. 121 imposing a statewide "stay at home" order until April 29, 2020, the Commission issued an order postponing the previously scheduled public witness hearings pending further order.

On April 29, 2020, the North Carolina Attorney General's Office (AGO) filed a notice of intervention in this docket pursuant to N.C. Gen. Stat. § 62-20.

The Public Staff filed the testimony of Public Staff witness Hinton on May 19, 2020, and on May 26, 2020, it filed the testimony and exhibits of its witnesses Michelle M. Boswell, Lindsay Darden, Lynn Feasel, D. Michael Franklin, Windley E. Henry, and Charles M. Junis.

On May 21, 2020, Aqua NC filed the revised exhibits to the direct testimony of its witnesses Shannon Becker and Edward Thill. On June 2, 2020, Aqua NC filed the rebuttal testimony of Company witness D'Ascendis.

On June 11, 2020, Aqua NC filed a Petition for Approval of an Order Allowing Deferral of Revenues in Lieu of Rates Under Bond or, Alternatively, Notice of Intent to Place Temporary Rates in Effect Subject to an Undertaking Refund Pursuant to N.C.G.S. § 62-135 (Petition).

On June 12, 2020, Aqua NC filed the rebuttal testimony and exhibits of its witnesses Amanda Berger, Dean R. Gearhart, Paul J. Hanley, Joseph Pearce, George Kunkel, and Edward Thill, and on June 13, 2020, it filed the joint rebuttal testimony and exhibits of witnesses Becker and Pearce.[1] On June 15, 2020, Aqua NC filed the rebuttal testimony of its witness Gearhart with corrected Rebuttal Exhibit 1, and the joint rebuttal testimony of its witnesses Becker and Pearce with corrected Rebuttal Exhibits.

On June 16, 2020, the Public Staff and the AGO filed a joint response to Aqua NC's June 11, 2020 Petition requesting deferral of revenues or, alternatively, implementation of rates under bond.

On June 19, 2020, Aqua NC filed revisions to the rebuttal testimony and exhibits of Company witnesses Berger and Thill.

On June 22, 2020, the Public Staff filed the corrected testimony of witness Junis and the corrected joint testimony and exhibits of witnesses Henry and Junis.

On June 23, 2020, at 9:30 a.m., the Commission convened the expert witness hearing as scheduled, but due to the State of Emergency relating to COVID-19, the hearing was recessed until July 6, 2020, for the purpose of receiving expert witness testimony by virtual means using the Webex electronic platform.

Also on June 23, 2020, the Commission issued an order denying use of a revenue deferral mechanism in lieu of rates under bond. By the same order, the Commission approved Aqua NC's financial undertaking associated with placing partial, temporary rates under bond pursuant to N.C.G.S. § 62-135 and approved the Company's Notices to Customers. The Commission noted that whether to exercise the remedy provided by N.C.G.S. § 62-135 is not a determination for the Commission but is instead the Company's choice and found that Aqua NC's motion satisfied the statutory requirements necessary to place new rates into effect on July 30, 2020 on a partial, temporary basis, subject to refund with interest at a rate of 10% per annum.

On June 29, 2020, the Commission issued an order rescheduling the public witness hearing for August 3, 2020, to be held in two sessions, beginning at 1:30 p.m. and 6:30 p.m. via virtual means. The order required Aqua NC to file verified reports addressing all customer service and service quality complaints expressed during each public witness hearing within 20 days of the conclusion of the hearing. The Public Staff was required, and intervenors were allowed, to file verified responses and any comments to Aqua NC's reports on or before September 4, 2020. Aqua NC was also required to provide the approved Notice to Customers to all affected customers no later than July 10, 2020.

Together with the Stipulation, Aqua NC filed a motion seeking Commission approval of revised Notices to Customers. In its motion, Aqua NC sought to implement partial, temporary rates under bond at a lower level than previously requested and lower than was set forth in the Notice

[1] Because June 13, 2020, fell on a Saturday, the joint rebuttal testimony of Aqua NC's witnesses Becker and Pearce was not marked filed by the Clerk's Office until the next business day, June 15, 2020.

to Customers in the Commission's June 23, 2020 Order. Also on July 1, 2020, Aqua NC filed its executed Undertaking to Refund pursuant to N.C.G.S § 62-135(c).

On July 1, 2020, Aqua NC and the Public Staff entered into and filed a Partial Settlement Agreement and Stipulation (Stipulation). The Stipulation resolved some of the issues between the two parties in this docket. However, the following unresolved issues still existed: (1) Conservation Pilot Program; (2) rate design; (3) water quality reporting; and (4) the in-service date of plant and Aqua NC's unitization process, further described herein (collectively, the Unresolved Issues).

On July 2, 2020, the Commission issued an order approving Aqua's revised Notices to Customers and accepting Aqua's financial undertaking subject to refund.

On July 7, 2020, at the Commission's request, the Public Staff filed Revised Exhibits I and II of Public Staff witness Windley E. Henry, Revised Exhibit I of Public Staff witness Lynn Feasel, and Revised Exhibits 7, 9, 13, 15, and 17 of Public Staff witness Charles M. Junis, updating said exhibits in light of the Stipulation.

This matter came on for the expert witness hearing on July 8, 2020, by virtual means using the Webex electronic platform. Aqua NC presented the testimony of its witnesses Becker, Berger, D'Ascendis, Gearhart, Hanley, Kunkel, Pearce, and Thill. The testimony of witnesses D'Ascendis, Hanley, Kunkel and Pearce was received into the record without examination of the witnesses by any party or the Commission. Witnesses Becker, Berger, Gearhart, and Thill were sworn in and subject to cross-examination. The Public Staff presented the testimony of its witnesses Boswell, Darden, Feasel, Franklin, Henry, Hinton, and Junis. The testimony of witnesses Boswell, Darden, Feasel and Hinton was received into the record without examination of the sponsoring witnesses. Witnesses Franklin, Henry, and Junis were made available for examination by the parties and the Commission. The hearing recessed on July 13, 2020, to be reconvened on August 3, 2020, to receive customer public witness testimony as scheduled.

On July 15, 2020, following the expert witness hearing but prior to the public witness hearing, Aqua NC filed its Confidential Late-Filed Becker Direct Exhibit 4, and on July 27, 2020, it filed a Late-Filed Exhibit with responses to Commissioner's questions.[1]

On July 17, 2020, the Public Staff filed its Late-Filed Exhibit 1 requesting the Commission to take judicial notice of the Commission's final orders in three prior Aqua NC rate cases. On July 20, 2020, the Public Staff filed its Late-Filed Exhibit 2 with responses to Commissioner's Questions of Public Staff witness Charles M. Junis.

The parties filed all late-filed exhibits requested by the Commission requested during the expert witness hearing. No party raised any objection to such exhibits and, therefore, said late-filed exhibits are deemed admitted into the record.

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[1] Unless otherwise indicated, the Commission uses the term "late-filed exhibit" to refer to exhibits filed after the close of a hearing.

On August 3, 2020, the public witness hearing was held in two sessions as scheduled. A total of 24 customers testified as public witnesses.

On August 17, 2020, the Public Staff and Aqua NC filed proposed orders, and the AGO filed a post-hearing brief.

On August 25, 2020, Aqua NC filed its Report on Customer Comments (Report on Customer Comments) from the Public Hearing held on August 3, 2020.

On September 5, 2020, the Public Staff filed its verified response to Aqua NC's Report on Customer Comments.

On September 11, 2020, Aqua NC filed its Reply Comments to the Public Staff's response to its Report on Customer Comments.

On September 25, 2020, Aqua NC and the Public Staff filed Supplemental Proposed Orders regarding testimony from the public hearing, responses to customer concerns, and water quality reporting requirements.

WHEREUPON, on the basis of Aqua NC's verified Rate Case Application, including the NCUC Form W-1; the Partial Settlement Agreement and Stipulation; the public witness testimony; the testimony and exhibits of Aqua NC witnesses, including the Company's late-filed exhibits; the testimony and exhibits of Public Staff witnesses, including the Public Staff's late-filed exhibits; and the entire record in this proceeding, the Commission now makes the following

FINDINGS OF FACT

General Matters

1. Aqua NC is a corporation duly organized under the law and is authorized to do business as a regulated investor-owned water and sewer public utility in the State of North Carolina. The Company is subject to the regulatory oversight of this Commission. Aqua NC is a wholly-owned subsidiary of Essential Utilities, Inc. (Essential Utilities)[1] of Bryn Mawr, Pennsylvania. Aqua NC's headquarters is located in Cary, North Carolina.

[1] On May 13, 2020, Aqua NC notified the Commission of Aqua America, Inc.'s name change to Essential Utilities, Inc, by submitting the Articles of Amendment filed with the Pennsylvania Department of State, Bureau of Corporations and Charitable Organizations, which recorded the change of corporate name from Aqua America, Inc. to Essential Utilities, Inc., effective February 3, 2020.

2. Aqua NC is subject to the jurisdiction of the Commission pursuant to Chapter 62 of the North Carolina General Statutes for adjudication of the Company's Application for a rate increase and for a determination of the justness and reasonableness of Aqua NC's proposed rates for its water and sewer utility operations in North Carolina.[1]

3. The test period for this rate case is the 12-month period of time ending September 30, 2019, adjusted for certain known and actual changes in plant, revenues, and costs that were not known at the time the case was filed but are based upon circumstances and events occurring or becoming known through March 31, 2020, and including up to the close of the expert witness hearing on July 13, 2020.

4. For the 12-month test period ending September 30, 2019, Aqua NC achieved a consolidated per books rate of return on common equity of 5.44%, or a rate of return on common equity of 5.77% when adjusted to remove goodwill.

5. Aqua NC's last general rate case was decided by Commission Order entered on December 18, 2018, in Docket No. W-218, Sub 497 (Sub 497 Rate Case Order).[2] From January 1, 2020 until July 29, 2020, Aqua NC's Commission approved rates for water and sewer service in all its service areas were in effect pursuant to the Commission's Order Approving Water and Sewer System Improvement Charges on a Provisional Basis and Requiring Customer Notice issued in Docket No. W-218, Sub 497A on January 6, 2020. On July 30, 2020, after appropriate customer notice, Aqua NC placed new rates into effect on a partial, temporary basis as allowed pursuant to N.C.G.S. § 62-135 in its Aqua NC Water, Aqua NC Sewer, and Brookwood Rate Divisions. Any amount of such temporary rates that may be finally determined by the Commission to be excessive are subject to refund with interest at a rate of 10% per annum.

The Rate Case Application

6. In summary, by its Rate Case Application, supporting documents filed on January 24 and 29, 2020, and additional filings on subsequent dates during the proceeding, Aqua NC sought an increase in its base rates and charges to its North Carolina customers of $6,819,722 along with other relief, including cost deferrals, changes to rate design, a conservation pilot program, and a consumption adjustment mechanism (CAM). The Rate Case Application was based upon a requested rate of return on common equity of 10.10%, an embedded long-term debt cost of 4.25%, and a capital structure of 50.00% common equity and 50.00% long-term debt.

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[1] Aqua NC has five rate divisions for its water and sewer operations in North Carolina: (1) Aqua NC Water; (2) Aqua NC Sewer; (3) Brookwood Water; (4) Fairways Water; and (5) Fairways Sewer.

[2] Pass-through rate increases for various purchased water and purchased sewer systems have been approved pursuant to N.C.G.S. § 62-133.11, subsequent to the Sub 497 Rate Case Order.

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The Stipulation

7. On July 1, 2020, Aqua NC and the Public Staff (Stipulating Parties) entered into and filed a Partial Settlement Agreement and Stipulation in this docket which resolved some of the disputed issues between the Stipulating Parties pursuant to N.C.G.S. § 62-92 and Commission Rule R1-24(c). The issues that were resolved constitute the entirety of what are sometimes referred to collectively herein as the Financial Issues. The four issues not resolved by the Stipulation include Aqua NC's proposed conservation pilot program; rate design; customer service and water quality reporting requirements; and the in-service dates of plant (UPIS) and the Company's unitization practices and policies.

8. The Stipulation is the product of the give-and-take in settlement negotiations between the Aqua NC and the Public Staff, is material evidence in this proceeding, and is entitled to be given appropriate weight in this case, along with other evidence from the Company, the Public Staff, and the AGO, as well as testimony of public customer witnesses concerning the Company's Rate Case Application.

Stipulated Adjustments to Cost of Service

9. The Stipulation provides for a broad range of accounting adjustments, which are set forth in detail at Settlement Exhibit I, appended to the Stipulation filed on July 1, 2020.

10. The Stipulating Parties agree that the Stipulation is a settlement of certain disputed issues between the parties in this docket and will not be used as a rationale for future arguments on contested issues brought before the Commission.

11. The accounting adjustments outlined in Settlement Exhibit I are just and reasonable to all parties in light of all the evidence presented, serve the public interest, and should be approved.

12. The Company's updates through August 14, 2020, to certain revenues, expenses, and investments, as agreed to and adjusted in the Stipulation, are appropriate for use in this proceeding.

Stipulations Pertaining to Rate of Return on Common Equity, Overall Return, Capital Structure, and Cost of Debt

13. The cost of capital and revenue increase approved in this Order are intended to provide Aqua NC, through sound management, the opportunity to earn an overall rate of return of 6.81%. This overall rate of return is derived from applying an embedded cost of debt of 4.21%, and a rate of return on common equity of 9.40%, to a capital structure consisting of 50.00% long-term debt and 50.00% equity.

14. The stipulated 9.40% rate of return on common equity for Aqua NC is just and reasonable in this general rate case.

15. The stipulated 50.00% equity and 50.00% long-term debt ratio is a reasonable capital structure for Aqua NC in this case.

16. The stipulated 4.21% cost of debt for Aqua NC is reasonable for the purposes of this case.

17. The provision of continuous safe, adequate, and reliable water and wastewater utility service by Aqua NC is essential to the Company's customers.

18. The rate increase approved in this case, which includes the stipulated rate of return on common equity and capital structure, will be difficult for some of Aqua NC's customers to pay, particularly the Company's low-income customers, and especially during the unprecedented economic crisis resulting from the COVID-19 pandemic that gave rise to the Commission's disconnection moratorium.[1]

19. The stipulated rate of return on common equity and capital structure approved by the Commission appropriately balance the benefits received by Aqua NC's customers from the Company's necessary investments in the provision of safe, adequate, and reliable water and wastewater utility service with the difficulties that some of Aqua NC's customers will experience in paying the Company's increased rates.

20. The stipulated 9.40% rate of return on common equity and the 50.00% equity capital structure approved by the Commission in this case appropriately balance Aqua NC's need to obtain equity and debt financing with the ratepayers' need to pay the lowest possible rates.

21. The authorized levels of overall rate of return and rate of return on common equity set forth above are supported by competent, material, and substantial record evidence, are consistent with the requirements of N.C.G.S. § 62-133, and are fair to Aqua NC's customers generally and in light of the impact of changing economic conditions.

Acceptance of Stipulation

22. Based upon all of the evidence in the record, including consideration of the public witness testimony and the evidence from the AGO, who did not join the Stipulation, the provisions of the Stipulation are just and reasonable to the customers of Aqua NC and to all parties to this proceeding and serve the public interest. Therefore, the Stipulation should be approved in its entirety. In addition, the Stipulation is entitled to substantial weight and consideration in the Commission's decision in this docket.

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[1] See Order issued on March 19, 2020, in Docket Nos. M-100, Sub 158. By Order issued on July 29, 2020, the Commission determined that, after appropriate customer notice in accordance with Commission rules, all jurisdictional electric, natural gas, water, and wastewater public utilities may resume customer disconnections due to nonpayment for bills first rendered on or after September 1, 2020.

Withdrawal of Conservation Normalization Adjustment and CAM Requests

23. For purposes of calculating average consumption for use in this proceeding, Aqua NC sought approval to apply a conservation normalization factor to the three-year average historical consumption figures for each of the Company's three water rate divisions. Aqua NC also proposed implementation of a CAM for approval by the Commission pursuant to N.C.G.S. § 62-133.12A. During the course of this proceeding, the Company withdrew both these requests and the Commission makes no further finding as to either request.

Contested Issues

Rate Design (Excluding Conservation Pilot Program)

24. It is reasonable and appropriate that Aqua NC's rate design for water utility service provided to its residential customers should continue to be based on the following fixed/variable ratios which were proposed by the Public Staff and approved by the Commission in the Company's Sub 497 rate case: 40%:60% for the Aqua NC Water Rate Division; 41%:59% for the Brookwood Water Rate Division; and 44%:56% for the Fairways Water Rate Division. These water rate design ratios promote water efficiency and conservation while also providing Aqua NC a reasonable opportunity to recover the approved revenue requirements in this proceeding for its three water rate divisions.

25. To further promote water conservation and to give customers more control over their monthly wastewater bills, it is appropriate to implement volumetric wastewater rates with an 80% base facility charge and a 20% volumetric charge for all the Aqua NC and Fairways wastewater customers that receive water utility service from Aqua NC or Fairways water, and for whom water meter readings are presently available, excluding the approximately 800 sewer customers in the Aqua NC Water Rate Division Conservation Pilot Program.

26. It is reasonable and appropriate for all Aqua NC and all Fairways wastewater customers that do not receive metered water utility service from Aqua NC or Fairways to remain monthly flat rate wastewater customers at this time.

27. As a result of the change from flat to metered sewer rates for residential customers in the Aqua NC Sewer and Fairways Sewer Rate Divisions and the approval of the Conservation Pilot Program in the Aqua NC Water Rate Division discussed below, the Public Staff's recommended change to a fixed/variable ratio of 30%:70% for Aqua NC's three water rate divisions is not appropriate at this time. The rate design changes approved herein will provide Aqua NC's customers an opportunity to achieve additional water conservation in the Aqua NC Sewer and Fairways Sewer Rate Divisions while also providing valuable, tangible information concerning the use of two new rate design structures for Aqua NC.

28. Aqua NC should evaluate the effect on customers' monthly sewer bills as a result of the implementation of metered sewer rates for residential customers. In an annual report to the Commission, Aqua NC should compare the monthly historical consumption to the current monthly consumption for the customers converted from a flat sewer rate to a metered sewer rate to

determine the change in consumption levels. Such report should state, at a minimum, the subdivision name, the number of customers billed (historical month and current month), monthly consumption billed (historical and current), and the sewer revenues billed (historical month and current month).

29. Under a metered sewer pricing rate structure, customers who irrigate through their primary household meter will receive a stronger conservation signal than the customers who irrigate through a separate irrigation meter. Aqua NC should evaluate and propose a separate rate for water provided through an irrigation meter in future rate case proceedings. Aqua NC should also evaluate and propose future rate design structures that provide pricing incentives for reducing irrigation use for all customers who use an in-ground irrigation system.

Conservation Pilot Program

30. By Order entered in Docket No. W-100, Sub 59 on March 20, 2019, the Commission initiated an Investigation of Rate Design for Major Water Utilities, requesting, in pertinent part, "a discussion of rate design proposals that may better achieve revenue sufficiency and stability while also sending appropriate efficiency and conservation signals to consumers." In response to that request, Aqua NC proposed, in this rate case, to implement a Conservation Pilot Program for residential customers in five of the Company's service areas in North Carolina: The Cape; Arbor Run; Bayleaf Master System; Merion; and Pebble Bay.[1] Aqua NC stated the purpose of the proposed pilot is to examine a new rate structure designed to send conservation-inducing price signals to residential customers, while preserving the Company's ability to achieve sufficient and stable cost recovery. As proposed, the Company would implement a new inclining block rate structure.

31. The focus of Aqua NC's proposed pilot program is to provide rate relief for customers whose usage falls within lower usage blocks and to induce conservation for those customers whose usage falls within higher usage block levels.

32. The five service areas which Aqua proposed to include in its pilot program involve two of the Company's Rate Divisions (Aqua NC Water and Fairways Water). As proposed, the pilot program would include nearly 11,000 premises, covers approximately 13% of the Company's water customers, and include representation in each of Aqua NC's geographical areas. The five pilot water service areas vary significantly in size, consumption volatility, and absolute level of consumption. Each of the five water systems serving the service areas proposed to be part of the pilot is experiencing stress to meet peak demand and could soon require capital investment if conservation is not realized in the near term.

33. For the pilot program, Aqua NC proposed four usage tiers with inclining block rates and separate irrigation rates to be charged to residential water customers in the Arbor Run, Merion, Pebble Bay, and Bayleaf Master System service areas (a portion of the Aqua NC Water Rate Division) and The Cape service area (Fairways Water Rate Division). The Company stated that its

[1] The Cape service area is located in the Fairways Water Rate Division, while the other four service areas are located in the Aqua NC Water Rate Division. Thus, the Company actually proposed to conduct two pilot programs.

pilot program proposal is contingent upon Commission approval of its proposed revenue reconciliation process specific to the pilot areas. According to AquaNC, the purpose of the proposed revenue reconciliation process is to assure that the Company will receive its full authorized revenue requirement, no more and no less.

34. Aqua NC's proposed pilot program considers irrigation rates to the extent the Company was able to do so. The Company has only 1,449 irrigation meters among its more than 80,000 water connections.[1] Some of Aqua NC's customers irrigate through their primary meter connections which do not provide a separate meter reading for the consumption related to irrigation use. Aqua NC's proposed pilot rates assign Block 3 and Block 4 rates for all separate irrigation meter usage; that is, Aqua NC Water customers with irrigation meters would pay the Block 3 charge for their first 15,000 gallons per month and the Block 4 rate for consumption above that threshold. Although Aqua NC is presently unable to assess separately irrigation-related consumption for customers irrigating through primary meters, the Company expects that most irrigation-related consumption would be captured in proposed Blocks 3 and 4 and that this proposed rate structure would provide equitable treatment and similar conservation signals to its irrigation customers regardless of the presence or absence of separate irrigation meters.

35. The Public Staff opposes Aqua NC's proposed pilot program contending that the Company has failed to demonstrate that the program, including the revenue reconciliation process, is reasonable or justified for the purposes of this case.

36. It is reasonable and appropriate for Aqua NC to implement a Conservation Pilot Program in a portin of its Aqua NC Water Rate Division for the approximately 6,530 customers in its Arbor Run, Merion, Pebble Bay, and Bayleaf Master System service areas but not in The Cape service area in its Fairways Water Rate Division.

37. Applying inclining block rates to all of the Company's customers should be analyzed in advance of implementation because there are many variabilities in an inclining block rate structure, from the number and size of the blocks to the various step points and the magnitude of the unit price difference between blocks. An analysis of the impact these variables have on the effectiveness of the new rate structure in promoting water efficiency and conservation should include both an evaluation of the municipal and town water and sewer systems operating in the State that currently utilize inclining block rate structures as well as actual customer reaction and changes in consumption observed through the implementation of Aqua NC's pilot program.

38. Aqua NC should compile monthly consumption data of customer accounts by blocks of per 1,000 gallons to properly design, evaluate, and implement a tiered inclining block rate structure. Aqua NC should file quarterly reports with the Commission on the consumption data and revenue collection related to customers included in the pilot program. The quarterly reports should be filed within 30 days after the end of the quarter.

[1] According to the Public Staff's late-filed exhibit filed on July 20, 2020 in this docket, there are three irrigation bills in the Bayleaf Master System service area, one in the Pebble Bay service area, and 478 in The Cape service area.

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39. Aqua NC should implement the pilot program for a period of time that allows the Company to accumulate sufficient information to analyze the results of the pilot and to apply such results to designing proposed future rate structures. Consequently, Aqua NC's pilot program should include at least two summer irrigation seasons but should conclude within three years of the implementation date or the effective date of new base rates in a general rate case application, whichever is earlier.

40. There are not presently any tiered rate structures approved for the water and sewer utilities regulated by the Commission. Implementation of tiered inclining block rate structures would be a significant change in rate design for the regulated water and sewer utilities. It is reasonable and appropriate to implement a pilot program in a portion of Aqua NC's Water Rate Division to allow Aqua NC to analyze the results on a smaller scale before designing and applying any one or more final rate designs to the larger population of Aqua NC. The application of a pilot program in a portion of Aqua NC's Water Rate Division should provide the Company, the Public Staff, and the Commission an opportunity to explore the effects of a tiered inclining block rate structure on a variety of customer types in several geographical areas in the State; to make comparisons of actual pilot program results to data pertaining to nonregulated entities (towns, municipalities, etc.) that utilize inclining block rates; to evaluate the feasibility of utiliznig inclining block rates rather than Aqua NC's current single-tier rate design structure compared to the resulting benefits in system operations and conservation; and to review Aqua NC's reports of the monthly consumption data of accounts by blocks of 1,000 gallons to ensure that all required information is captured prior to possible full or permanent implementation of inclining block rates in some or all of Aqua NC's service areas.

41. There are approximately 6,000 residential customers on the Bayleaf Master water system and there are less than 800 residential sewer customers. The Bayleaf Master water system customer base is not a uniform group of high-consumption households but rather includes some diversity with respect to water usage. The Bayleaf Master System is a water system with a history of marginally adequate well water capacity during extended periods of high demand that typically occur during hot, dry weather which historically has resulted in heavy lawn and shrub irrigation.

42. Although there is opportunity for both conservation and operational relief with implementation of a pilot program in The Cape service area, it is not appropriate to implement such a program in this proceeding because the metered water rates for the Fairways Water Rate Division are significantly lower in comparison to the Aqua NC's Water and Brookwood Water Rate Divisions and thus will not provide meaningful results to extrapolate across the Company's full customer base in future rate design planning. Further, of the approximately 4,251 customers to be included in The Cape pilot program, the majority of the customers, 2,876 customers, are both water and sewer customers and 1,375 are water-only customers. Consequently, the approval of metered sewer rates for The Cape service area will send a conservation signal to high volume water users through the metered sewer charge. Implementing both metered sewer and an increasing block rate structure would complicate the evaluation and analysis of the pilot program and the proposed revenue reconciliation process.

43. It is reasonable and appropriate that a Conservation Pilot Program be designed to maintain revenue sufficiency and stability for Aqua NC. A revenue reconciliation mechanism is

appropriate to support the Company's reasonable opportunity to recover its full Commission-approved revenue requirements despite implementation of a Conservation Pilot Program.

44. For purposes of implementing the Conservation Pilot Program in a portion of the Aqua NC Water Rate Division, a revenue reconciliation process applicable only to the pilot group is in the public interest. It is reasonable and appropriate that a revenue reconciliation process as set forth by the Company be integral to the pilot program; however, such revenue reconciliation process allowed in this docket for this specific purpose is not intended to establish the process by which any future revenue reconciliation for Aqua NC or other regulated utilities related to actual consumption variances from Commission-approved levels in general rate case proceedings as allowed by N.C.G.S. § 62-133.12A will be calculated.

Utility Plant in Service and Plant Unitization

45. The Commission entered an Order granting a general rate increase to Aqua NC in Docket No. W-218, Sub 274 on April 8, 2009 (Sub 274 Rate Case Order). In its Sub 274 Rate Case Order, the Commission approved a joint stipulated settlement (Sub 274 Joint Stipulation) filed by the Public Staff, Aqua NC, and an intervenor party on January 27, 2009, which settled all issues in the case.[1]

46. Paragraph 34 of the Sub 274 Joint Stipulation provided as follows:

> Aqua will adopt a consistent, accurate, and complete accounting system for its detailed plant records that maintains its plant records in compliance with the uniform system of accounts. Furthermore, this system should keep plant additions on a system specific basis, as required by the Commission in Docket No. W-274, Sub 251. This should be done before the Company files another general rate case for any of its operations in North Carolina. If Aqua files a general rate case for any of its operations based on a test year in which the plant records have not been brought into compliance, any additional rate case costs due to the inadequate records will not be borne by the ratepayers.[2]

47. Paragraph 37 of the Sub 274 Joint Stipulation provided as follows: "Aqua will review its procedures for determining when projects are completed and should be closed and file its recommended changes to its procedures within 90 days from the date of the order in this case."[3]

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[1] The Attorney General (AGO), who was also a party to the rate case, made a filing on March 13, 2009, which stated that the AGO did not support or oppose the Joint Stipulation and Partial Settlement Agreement filed in the Sub 274 docket and, likewise, did not support or oppose the Joint Proposed Order.

[2] This provision was incorporated by the Commission as Ordering Paragraph No. 8 of the Sub 274 Rate Case Order.

[3] This provision was incorporated by the Commission as Ordering Paragraph No. 12 of the Sub 274 Rate Case Order.

48. Paragraph 44 of the Sub 274 Joint Stipulation provided as follows:

> Aqua will file a report every three months on the status of its compliance with Items 34 through 43 set forth herein. This report should contain for each item: (1) whether the Company has complied with the item, (2) a detailed description of the steps taken to comply, and (3) if Aqua has not yet complied, the remaining steps to be taken and the expected date of completion.[1]

49. The Company subsequently filed eight quarterly status reports with the Commission in the Sub 274 Rate Case Docket. The first quarterly report was filed on June 30, 2009. In that report, Aqua NC stated, in pertinent part, that:

> Pursuant to its own commitment and to Commission Order, Aqua is aggressively engaged in the task of consolidating and rationalizing the myriad of accounting systems that exist throughout its 42-county footprint into one, integrated system. This requires extensive coordination and effort, using the resources of both Aqua North Carolina, Inc. and Aqua America, Inc., as well as the engagement of Accenture, a nationally recognized consulting firm. It is a significant, expensive and on-going process—one that is necessary to complete the transition from a host of separate systems to a rationally organized, statewide Company. Additional consultant engagements are required for the studies that Aqua is tasked to complete, which address the impact of volumetric sewer rates and inclining block water rates. The Company is pleased to report that significant progress has been made on all assignments. More remains to be done, and reports on the progress will be made quarterly or as otherwise required. In addition, the Company communicates regularly with the Public Staff on the progress that is being made on these and other activities.

Regarding its compliance with Ordering Paragraph 8 of the Sub 274 Rate Case Order, Aqua NC stated that:

> Aqua's expansion in North Carolina has occurred primarily through acquisition of a number of other systems, which has in turn resulted in the existence of records in a wide variety of formats. Reconciliation of disparate systems into new and standardized systems is a major undertaking, as was evidenced by the conversion of numerous customer information systems to Banner. The Company has chosen an asset management system called "Power Plant"[2] as the platform for conversion of existing records and for asset tracking in the future. This conversion requires significant support of the North Carolina operation by Aqua America resources in Pennsylvania and other states. After extensive internal accounting work, the

[1] This provision was incorporated by the Commission as Ordering Paragraph No. 18 of the Sub 274 Rate Case Order.

[2] According to information provided in this rate case proceeding, the asset management software is properly referred to as "PowerPlan"

> conversion to Power Plant is well underway and North Carolina is scheduled to be converted by December 31, 2009. It should also be noted that this is more than a conversion of existing systems. Many of the processes that are integral to the success of the systems are also being evaluated and standardized. Aqua has discussed the status of the project with the Public Staff Accounting Division and they are aware of the steps being taken.

Regarding its compliance with Ordering Paragraph 12 of the Sub 274 Rate Case Order, Aqua NC stated that:

> On a monthly basis the Accounting Department sends the Regional Managers a CWIP report for review, with the request that the Managers notify Accounting of projects that are complete and in service. Accounting allows 30 to 60 days for any trailing costs to be charged to these in-service activity numbers before closing the asset. Attention to this process is also part of the scope of work involved in the Accenture engagement. Aqua has discussed the status of the project with the Public Staff Accounting Division and they are aware of the steps being taken. (Note: the work with Accenture is on-going and, in the meantime the described monthly review and cross-check between the Accounting Department and the Regional Managers is in place. Additional information will be provided in the next quarterly report, and Aqua submits this as the report required by July 7, 2009).

50. Aqua NC's second quarterly report was filed on September 29, 2009. In that report, Aqua NC reiterated what it had previously stated with regard to the Company's compliance with Ordering Paragraph No. 8 and added that:

> In the interim and prior to full integration of Power Plant, Aqua is maintaining plant records in compliance with the Uniform System of Accounts and is keeping plant additions on a system-specific basis, as required.

Regarding the Company's compliance with Ordering Paragraph No. 12, Aqua NC stated that:

> On a monthly basis the Accounting Department sends the Regional Managers a CWIP report for review, requesting that the Managers notify Accounting of projects that are complete and in service. Accounting allows 30 to 60 days for any trailing costs to be charged to these in-service activity numbers before closing the asset. Aqua has discussed the status of the project with the Public Staff Accounting Division, which is aware of the steps being taken.

51. Aqua NC's sixth quarterly report was filed on September 30, 2010. With regard to the Company's compliance with Ordering Paragraph No. 8, Aqua NC stated that:

> The "Power Plant" asset management system has been adopted as Aqua's new plant record platform. It is currently being utilized to record and maintain accurate and complete plant records. Historic assets were converted August 27, 2010, with all

available system detail. Unitization and recording of plant additions on a system specific basis was initiated in Q2 2010.

Aqua respectfully submits that this constitutes a report of compliance in full with the Commission's Ordering Paragraph #8.

52. On June 29, 2011, the Commission entered an Order Terminating Quarterly Reporting Requirement in Docket No. W-218, Sub 274. In support of its Order, the Commission stated that:

> On March 31, 2011, Aqua North Carolina, Inc. (Aqua NC or Company) filed its Eighth Quarterly Status Report as required pursuant to Decretal Paragraph No. 18 of the Commission's April 8, 2009 Order Granting Partial Rate Increase and Requiring Customer Notice, in the above-captioned docket. In said report, Aqua NC requested that the Commission accept such report as the final quarterly report required by the Commission's April 8, 2009 Order[1] or, in the alternative, hold in abeyance any further quarterly reporting requirements pending issuance of the Commission's final Order in Aqua NC's current rate case proceeding, Docket No. W-218, Sub 319.
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> Public Staff witness Katherine A. Fernald testified under cross-examination at the June 16, 2011 evidentiary hearing in Docket No. W-218, Sub 319, that the Public Staff had reviewed the various reports filed by Aqua NC in response to the Commission's April 8, 2009 Order and opined that such reports have addressed the matters noted in Decretal Paragraph Nos. 8 through 17 of such Order. Furthermore, Public Staff witness Fernald testified that Aqua NC has complied with all of the reporting requirements set forth in Decretal Paragraph No. 18 of the Commission's April 8, 2009 Order.
>
> WHEREUPON, in consideration that Aqua NC has fully complied with all of the reporting requirements set forth in Decretal Paragraph No. 18 of the Commission's April 8, 2009 Order, the Presiding Commissioner finds good cause exists to accept Aqua NC's Eighth Quarterly Status Report as the final quarterly report and to terminate the present quarterly reporting requirements in Docket No. W-218, Sub 274, as requested by the Company.

53. Aqua NC has operated under the PowerPlan accounting system since August 27, 2010, with unitization and recording of plant additions on a system-specific basis having been initiated in the second calendar quarter of 2010. Since that time, Aqua NC has had three general rate cases (Subs 319, 363, and 497) prior to the Company's current Sub 526 rate case. In none of those cases was an allegation raised by any party, including the Public Staff, that Aqua NC's utility

[1] Aqua NC submitted in its Seventh Quarterly Status Report filed on December 29, 2010, for the quarter ending December 31, 2010, that it had complied with all of the reporting requirements pursuant to Decretal Paragraph No. 18 of the Commission's April 8, 2009 Order. Consequently, Aqua NC noted in its Eighth Quarterly Status Report that the Company has nothing new or additional to report in such quarterly filings which presents the issue of whether the quarterly filing requirement should be terminated. [This footnote was included in the Commission's June 29, 2011 Order].

plant in service (UPIS) and unitization practices and policies did not conform with the Uniform System of Accounts or that the Company's depreciation practices were deficient in any way.

54. In Aqua NC's past three general rate cases, there was no indication that the accounting issues noted by the Public Staff in the Sub 274 rate case were not fully resolved. In the current Sub 526 rate case, the Public Staff contends that Aqua NC's unitization practices and policies are problematic and not appropriate.

55. Aqua NC's long-standing practice and policy has been that plant additions begin to depreciate on the unitization date, not on the in-service date. The unitization date is the date when the asset is removed from construction work in progress and added to plant in service. According to Aqua NC's internal accounting procedures, a period of 30 to 60 days is allowed for any trailing costs to be charged to the projects before closing the asset to plant in service.

56. Aqua NC's use of the half-year depreciation convention as allowed by Generally Accepted Accounting Principles reasonably serves to minimize the impact of the unitization date during a calendar year being delayed beyond 30 to 60 days for any trailing costs to be recorded.

57. The Public Staff challenges Aqua NC's unitization practices and policies under PowerPlan for some of the Company's utility plant additions in this case and proposes the recognition of additional accumulated depreciation for those challenged projects.[1]

58. The Public Staff maintains that Aqua NC's UPIS practices and policies are applied inconsistently for a majority of the Company's CWIP projects. Aqua NC's accounting practices since the filing of its first quarterly status report per the Sub 274 Joint Stipulation and Rate Case Order have resulted in some assets being closed more than 60 days after the asset's in-service date. In these instances, the Company has on occasion continued to accrue Allowance for Funds Used During Construction (AFUDC) after the asset's in-service date and has frequently postponed the start of depreciation until well after the asset's in-service date. This practice has led to an artificial decrease in accumulated depreciation and corresponding increase in rate base, thereby increasing the return on the unamortized balance of plant in service. The Public Staff takes issue with Aqua NC's unitization dates and the accrual of depreciation when an asset is placed in service in one calendar year but unitization occurs in the next calendar year.

59. Accrual of AFUDC should end on the in-service date of an asset. With respect to depreciation, Aqua NC's current UPIS unitization policy is acceptable if utilized consistently by Aqua NC with strict adherence to a period of 30 to 60 days for any trailing costs to be charged to the projects before closing the asset to plant in-service. Aqua NC should pay particular attention to plant in-service dates occurring near the end of the calendar year such that the one-half year's depreciation expense is recorded in the year the plant is placed in service to the maximum extent possible.

[1] Witness Henry states that in Aqua NC's May 1, 2019 WSIC/SSIC application, the Public Staff adjusted accumulated depreciation for plant additions that were reclassified by the Public Staff from 2019 additions to 2018 additions.

60. Aqua NC should conduct a comprehensive review of its current procedures and policies for determining when projects are complete, in-service, and booked to plant in service and file the Company's findings with respect to its internal accounting practices and policies and any plans or recommendations regarding changes in those procedures and policies within 90 days of the date of the Order in this proceeding.

61. Aqua NC's comprehensive review of its UPIS practices and policies should include an analysis of whether the Company can utilize the functionality provided by PowerPlan to book completed but not classified costs on the in-service date and on a continual basis shortly thereafter as invoices are received and paid until the entire project can be unitized to ensure that AFUDC ends and depreciation begins on the in-service date.

62. Until such time that Aqua NC reports to the Commission concerning its prospective UPIS practices and policies to address the issue as to whether the Company can utilize PowerPlan to begin depreciation for an asset as of the in-service date and the Commission renders its decision in this regard, the Company should continue its current policy of ceasing AFUDC accrual as of the plant in-service date and beginning depreciation on the unitization date. Aqua NC should record the CWIP costs to plant in service such that the projects begin depreciating within 30 to 60 days after the in-service date.

Ratemaking and Revenue Requirement Issues

63. It is reasonable and appropriate to determine the revenue requirement for Aqua NC using the rate base method as allowed by N.C.G.S. § 62-133.

64. By its Application, Aqua NC initially requested a total annual revenue increase in its water and sewer rates of $6,819,722, an 11.20% increase over the total revenue level generated by the rates currently in effect for the Company.

65. The original cost rate base used and useful in providing service to the Company's customers is $135,909,809 for Aqua NC Water operations, $60,371,609 for Aqua NC Sewer operations, $3,345,093 for Fairways Water operations, $10,435,206 for Fairways Sewer operations, and $27,073,706 for Brookwood Water operations, for a total rate base for combined operations of $237,135,423.

66. The appropriate levels of total operating revenues under present rates for use in this proceeding are $39,190,819 for Aqua NC Water operations, $16,457,554 for Aqua NC Sewer operations, $1,249,860 for Fairways Water operations, $2,149,107 for Fairways Sewer operations, and $6,692,049 for Brookwood Water operations, for a total for combined operations of $65,739,389.

67. Accumulated depreciation consists of the following balances for water and sewer operations:

Aqua NC Water Operations:	$90,717,400
Aqua NC Sewer Operations:	$44,951,137
Fairways Water Operations:	$ 3,544,128
Fairways Sewer Operations:	$ 2,601,325
Brookwood Water Operations	$ 9,365,674

68. Contributions in aid of construction (CIAC), reduced by accumulated amortization of CIAC, consist of the following amounts for water and sewer operations:

Aqua NC Water Operations:	$61,724,928
Aqua NC Sewer Operations:	$52,124,015
Fairways Water Operations:	$ 5,819,673
Fairways Sewer Operations:	$ 5,923,775
Brookwood Water Operations	$ 2,427,237

69. It is reasonable and appropriate for Aqua NC to recover total rate case expenses of $985,454 related to the current proceeding to be amortized and collected over a three-year period, for an annual level of rate case expense of $328,484. As stipulated, this amount does not include a return or carrying costs on the unamortized balance. Unamortized rate case expense from Docket No. W-218, Sub 497 totals $419,435, and it is reasonable and appropriate for Aqua NC to recover these costs over a three-year period for an annual level of $139,812. The total annual rate case expense amortization for both dockets is $468,296.

70. It is reasonable and appropriate to use the current statutory regulatory fee rate of 0.13% to calculate Aqua NC's revenue requirement.

71. It is reasonable and appropriate to use the current state corporate income tax rate of 2.50% and the applicable 21.00% federal corporate income tax rate to calculate Aqua NC's revenue requirement.

72. Aqua NC is entitled to changes in rates that will produce the following levels of total operating revenues, after pro forma adjustments:

	Service Revenues	Other Rev. & Uncollectibles	Total Operating Revenues
Aqua NC Water	$38,546,489	$ 644,330	$39,190,819
Aqua NC Sewer	$16,426,070	$ 31,484	$16,457,554
Fairways Water	$ 1,159,708	$ 90,152	$ 1,249,860
Fairways Sewer	$ 2,152,586	$ (3,479)	$ 2,149,107
Brookwood Water	$ 6,433,919	$ 258,130	$ 6,692,049
Total Aqua NC	$64,718,772	$1,020,617	$65,739,389

These levels of revenues will allow Aqua NC the opportunity to earn a 6.81% overall rate of return, which the Commission has found to be reasonable upon consideration of the findings in this Order.

WATER AND SEWER – RATE INCREASE

73. The Commission-approved rates will provide Aqua NC with an increase of $3,446,081 in its annual level of authorized service revenues through rates and charges approved in this case, consisting of an increase for Aqua NC Water operations of $1,986,986, an increase for Aqua NC Sewer operations of $818,431, an increase for Fairways Water operations of $20,949, a decrease for Fairways Sewer operations of $37,004, and an increase for Brookwood Water operations of $656,719. After giving effect to these authorized increases in water and sewer revenues, the total annual operating revenues for the Company will be $65,739,389, consisting of the following levels of just and reasonable operating revenues:

Aqua NC Water	$ 39,190,819
Aqua NC Sewer	$ 16,457,554
Fairway Water	$ 1,249,860
Fairways Sewer	$ 2,149,107
Brookwood Water	$ 6,692,049

Water and Sewer System Improvement Charges

74. Aqua NC's right to charge a Water System Improvement Charge (WSIC) and a Sewer System Improvement Charge (SSIC) was initially granted by the Commission in Docket No. W-218, Sub 363 by Order issued May 2, 2014.

75. Pursuant to Commission Rules R7-39(k) and R10-26(k), the WSIC and SSIC mechanisms presently in effect are reset at zero as of the date this Order is issued.

76. The Ongoing Three-Year Plan filed by Aqua NC in Docket No. W-218, Sub 497A on March 2, 2020, is reasonable and meets the requirements of Commission Rules R7-39(m) pertaining to WSIC and R10-26(m) pertaining to SSIC.

Customer Concerns – Service and Water Quality-Related Issues

77. As of December 31, 2019, Aqua NC served approximately 80,978 water customers and 19,583 wastewater customers. Aqua NC owns and operates 741 water systems consisting of over 1,400 wells along with 59 wastewater systems and 203 collection systems across 51 counties in North Carolina.

78. A total of 24 Aqua NC customers testified at the two sessions of the public hearing held August 3, 2020, via Webex. The customers were from 21 subdivisions and 18 different systems. The testimony received during those two sessions of the public hearing covered secondary water quality concerns, customer service concerns, opposition to rate increases, and preferred rate design options.

79. Customer witnesses who testified regarding water quality complained specifically about discolored water, sediment buildup related to iron and manganese concentrations in the water, damage to appliances, intermittent aeration in the water, discoloration of household fixtures, unsatisfactory customer service related to Aqua NC's responsiveness and dissemination of inaccurate and insufficient information regarding such matters as flushing and service outages, and

the existence of Total Trihalomethane (TTHM) exceedance in one system. Some customers who complained of water quality issues testified that they do not drink the water supplied by Aqua NC and, instead, purchase bottled water for drinking and cooking. Several customers testified that they have incurred expense to have household filters installed (by non-Aqua NC affiliated vendors) in an effort to improve the quality of water supplied to their homes by Aqua NC. Seven of 24 customers who testified receive their water supply from the Bayleaf Master System.

80. Other specific concerns to which customers testified, which are not water quality related, include the magnitude of the rate increase requested by Aqua NC and the flat-rate sewer methodology rate design. One customer, who testified at the hearing complained that she had not received sufficient notice of the public hearing.

81. As of September 29, 2020, the Commission and Public Staff had received 19 written consumer statements of position which have been filed in Docket No. W-218, Sub 526CS.[1] Customers statements primarily express opposition to Aqua NC's proposed rate increase while a few indicate dissatisfaction with water quality due to secondary water quality issues and the Company's customer service.

82. Aqua NC filed verified reports with the Commission which address the concerns raised by the witnesses at both sessions of the August 3, 2020 customer witness public hearing. The reports also address the issues that appeared to apply across systems and discuss remedial efforts being taken at the system level. The reports address customer specific solutions, explaining that: (a) naturally-occurring iron and manganese are present in the groundwater supply that is the source of water for many of the Company's systems; (b) the levels of iron and manganese in the Company's systems meet applicable regulatory standards and pose no health risk to users; (c) the presence of iron and manganese in the water can cause water discoloration, problems with household appliances, and staining of fixtures and laundry; (d) the Company has employed various strategies to address the elevated levels of iron and manganese in its water systems (e.g., flushing, chemical sequestration, and installation of various filters); and (e) the Company works with the Public Staff and DEQ to devise optimal plans to better address the problem of iron and manganese in the Company's water systems.

83. Though the customers' comments and the evidence, particularly with respect to secondary water quality issues, justify the continuation of efforts to address secondary water

[1] The number of consumer statements of position received in the current rate case contrasts with Aqua NC's last rate case, (W-218, Sub 497), wherein ninety-three (93) customer statements were filed with the Chief Clerk, between April 16, 2018 and November 15, 2018.

quality, Aqua NC's performance with respect to secondary water quality and service has continued to improve. Additionally, there were no complaints during the public hearing regarding primary water quality concerns.

Quality, Remediation Efforts, Environmental Compliance and Communication

84. DEQ secondary water quality standards address the acceptable levels of certain constituents, including iron and manganese, in drinking water. Secondary water quality standards serve as guidelines to operators of water systems on keeping these elements, which are not considered to pose health risks, at levels that consumers will not find objectionable for drinking or consuming due to taste, color, and odor effects.

85. While the DEQ secondary water quality standards serve as guidelines to assist water systems in managing water qualities such as taste, color, and odor, they do not purport to address the suitability or acceptability of water for uses other than drinking, cooking, and human ingestion. Separate and apart from health concerns, the degree or magnitude of water taste, color, and odor problems resulting from elevated levels of iron and manganese, which for purposes of health-related issues are sometimes designated and considered "aesthetic" concerns, often adversely impact the usefulness of water supplied and can significantly limit the benefit customers receive from the water service for which they pay. Persistent secondary water quality issues related to elevated concentrations of iron and manganese and customer service issues may also render the quality of service for some customers inadequate for non-consumptive purposes, such as bathing, cleaning, laundry, and use in appliances.

86. Though concerns persist, particularly in certain parts of Aqua NC's service territory regarding secondary water quality, including odor and staining attributes when the secondary elements exist at high levels in the water, the evidence showed significantly increased investment and operational attention to these issues. The Company's efforts are responsive to customer concerns, reflect additional investment and operational diligence, and, if sustained, should support continued improvement in secondary water quality and service.

87. The overall quality of water service provided by Aqua NC is adequate on a company-wide and system-wide basis. The Company meets DEQ's and the United States Environmental Protection Agency's health-based primary quality standards.

88. Operational compliance with environmental laws and regulation is essential to safe, adequate provision of water service. Aqua NC's compliance level with respect to water systems (of which it has over 700) is at the 99.9% level. The Company also achieved a wastewater operations compliance level of approximately 97% in 2018-2019.

89. The overall company-wide and system-wide quality of wastewater service provided by Aqua NC is adequate and the Company operates its wastewater treatment plants in a reasonable and prudent manner.

90. Operational changes and capital improvements should continue as needed to support Aqua NC's success in improving the quality of water in systems affected with elevated levels of iron and manganese.

91. Aqua NC's level and quality of communication with its customers continues to increase and strengthen, as indicated by the testimony of its customers, the substantial decrease over time in customer testimony and written consumer statements, the Company's evidence of its internal improvements, and its outreach to customers. Evidence of Aqua NC's improved communication is found in the development of the Bayleaf Advisory Group, enhancements to the Company's website, hiring of a dedicated staff member to facilitate handling of discolored water quality calls, and deployment of the "Close the Loop" program to assure that an Aqua NC employee contacts every customer who calls with a complaint as a means of follow-up after the customer's call or complaint has been addressed.

Regulatory Oversight and Compliance – Reporting Requirements

92. Aqua NC was subject to a series of filing and reporting requirements under the terms of the Commission's Sub 363 Rate Case Order which were continued in the Commission's Sub 497 Rate Case Order.

93. Ordering Paragraph No. 8 of the Sub 363 Rate Case Order required Aqua NC to file bi-monthly reports addressing water quality concerns raised by customers at the public hearings for 13 systems. Such reports were to describe what was being done by Aqua NC to address water quality issues, and the Sub 363 Rate Case Order included the specific contents required for each of these reports.

94. Ordering Paragraph No. 9 of the Sub 497 Rate Case Order required Aqua NC to continue to file bi-monthly reports addressing water quality concerns raised by customers at the public hearings in Docket No. W-218, Sub 363, in situations where the iron and manganese concerns remain, and in the Sub 497 proceeding, including but not limited to customers served within the Bayleaf Master System. With the exception of the Barton's Creek Bluffs, Lake Ridge Aero Park, and the Coachman's Trail Master System, these bi-monthly reports are no longer required.

95. Ordering Paragraph No. 12 of the Sub 363 Rate Case Order required Aqua NC to communicate to the Public Staff the Company's conversations with, reports to, and receipt of recommendations from DEQ to the Public Staff regarding the water quality concerns being evaluated and addressed in Aqua NC's systems in a timely manner. Such communication was required to be in a written format and provided, at a minimum, on a bi-monthly basis. Aqua NC was required to provide the Public Staff copies of: (a) Aqua NC's reports and letters to DEQ concerning water quality concerns in its systems; (b) responses from DEQ concerning reports, letters, or other oral or written communication received from Aqua NC; and (c) DEQ's specific recommendations to Aqua NC, by system, concerning each of the water quality concerns being evaluated by DEQ.

96. Ordering Paragraph No. 14 of the Sub 497 Rate Case Order required Aqua NC to continue to promptly provide to and share with the Public Staff information concerning all meetings and conversations (in summary note form) with, reports to, and the recommendations

of DEQ regarding the water quality concerns being evaluated and addressed in Aqua NC's systems. These communications were not to be considered or treated as formal reports authored by Aqua NC, but rather as notification of the occurrence of communications between the Company and DEQ, as well as the salient topics discussed. They were required to be submitted in a written format; and were to be provided, at a minimum, on a bi-monthly basis until otherwise ordered by the Commission. Without limitation on the foregoing, Aqua NC was required to provide the Public Staff copies of: (a) Aqua NC's reports and letters to DEQ concerning water quality concerns in its systems; (b) responses from DEQ concerning reports, letters, or other oral or written communication received from Aqua NC; (c) DEQ's specific recommendations to Aqua NC, by system, concerning each of the water quality concerns being evaluated by DEQ; and (d) communications from DEQ to Aqua NC indicating DEQ's dissatisfaction with Aqua NC's response to DEQ's concerns, directions or recommendations concerning water quality affected by iron and manganese.

97. The Public Staff has incorrectly interpreted the Commission's written guidance with respect to the above identified reporting requirements to apply to primary water quality concerns. All portions of Ordering Paragraphs 9 and 14 of the Sub 497 Rate Case Order refer to reporting requirements specifically related to secondary water quality issues only – no to primary water quality.

98. Aqua NC should continue to promptly provide to and share with the Public Staff information concerning any and all written communications to and from DEQ that relate to compliance with or deficiencies in compliance with the secondary water quality standards enforced by DEQ. These notifications shall include, but are not limited to, copies of NOVs and written recommendations of DEQ regarding the secondary water quality concerns being evaluated and addressed in Aqua NC's systems. Aqua NC's notice to the Public Staff shall be in writing, include all salient topics and content points, and be provided, at a minimum, on a bi-monthly basis. These notifications shall not be considered or treated as a formal report authored by Aqua NC, but rather as notification of the occurrence of communication between the Company and DEQ. Without limitation on the foregoing, Aqua NC shall provide the Public Staff copies of: (a) Aqua NC's reports and letters to DEQ concerning secondary water quality concerns in its systems; (b) responses from DEQ concerning reports, letters, or other written communication received from Aqua NC related to secondary water quality issues; (c) DEQ's specific recommendations to Aqua NC, by system, concerning each of the secondary water quality concerns being evaluated by DEQ; and (d) written communications from DEQ to Aqua NC indicating DEQ's dissatisfaction with Aqua NC's response to DEQ's concerns, directions or recommendations concerning secondary water quality affected by iron and manganese.

99. The Public Staff and Aqua NC are required to file a written report with the Commission, on March 1 and September 1 each year in which the WSIC is in effect, on secondary quality concerns that are affecting its customers. If a particular secondary water quality concern has affected or is affecting 10% of the customers in an individual subdivision service area or 25 billing customers in an individual service area, whichever is less, the customers affected and the estimated expenditures that are necessary to eradicate, to the extent practicable, secondary water quality issues related to iron and manganese through the use of projects that are eligible for recovery through the WSIC shall be detailed in the written report. The written report shall also contain a recommendation as to whether the Commission should order Aqua NC to pursue such corrective action and provide an underlying reason why the action should or should not be

undertaken. If there are no secondary water issues or if the secondary water quality issues are below the 10% or 25 customer threshold previously set forth, Aqua NC and the Public Staff shall so inform the Commission, but they need not report secondary water quality issues resolved by Aqua NC without the assistance or expectation of assistance of the WSIC.

100. It is not appropriate to change the frequency or nature of the semiannual secondary water quality report requirement, at this time.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1–5

General Matters

The evidence supporting these findings of fact is contained in the verified Application, the NCUC Form W-1, the testimony and exhibits (both prefiled and late-filed) of the witnesses, and the entire record in this proceeding. These findings and conclusions are informational, procedural, and jurisdictional in nature and are not contested by any party.

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

Rate Case Application and Stipulation

The evidence supporting these findings of fact is contained in the Stipulation and in the testimony of Aqua NC witnesses Becker, Gearhart, Thill, and D'Ascendis, and Public Staff witnesses Henry, Hinton, and Feasel, and the entire record in this proceeding. Specifically the evidence is found as follows:

- Settlement Exhibit 1, filed with the referenced July 1, 2020 Stipulation;
- Henry Revised Exhibits I and II with supporting schedules (including Feasel Revised Exhibit I with supporting schedules); filed July 7, 2020, which provide sufficient support for the annual revenue required for the issues resolved by the Stipulation;
- Additional Direct Testimony of Shannon Becker found in Transcript Volume 2, filed July 8, 2020;
- Henry Additional Direct Partial Settlement Agreement Exhibit 1;
- Additional Direct Testimony of Windley Henry found in Transcript Volume 4, filed July 9, 2020; and
- Public Staff's Late-filed Exhibits of Windley E. Henry and Charles M. Junis filed on August 17, 2020, which provide supporting schedules and exhibits for the stipulated revenue requirements.

WATER AND SEWER – RATE INCREASE

The Stipulation is the product of the give-and-take in settlement between the Stipulating Parties, is material evidence in this proceeding, and is entitled to be given appropriate weight in this case, along with other evidence from Aqua NC, the Public Staff, and the AGO, the other intervening party, along with (consumer statements of position and the sworn testimony of the public witnesses concerning the Company's Application).

The Stipulation settles only some of the disputed issues between the Stipulating Parties. The Unresolved Issues include:

A. Conservation Pilot Program;
B. Rate Design;
C. Reporting Requirements; and
D. The in-service date of plant and Aqua NC's unitization process.

On July 1, 2020, Aqua NC and the Public Staff filed the Stipulation, which resolved virtually all of the financial issues in this proceeding between them and provided for a revenue requirement increase of approximately $3,232,954 for combined operations based on the settled issues. The Stipulation is based upon the same test period as Aqua NC's Application, adjusted for certain changes in plant, revenues, and costs that were not known at the time the case was filed but occurred or became known by March 31, 2020.

The key aspects of the Stipulation, Section III, resolved the following revenue requirement issues, as between the Stipulating Parties:[1]

Test Period and Updates

Pursuant to Section III, Paragraph A of the Stipulation, the test period for this rate case is the 12 months ending September 30, 2019, 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 March 31, 2020. The salaries and wages, pensions and benefits, and payroll tax for Aqua NC employees were updated through March 31, 2020, based on the agreement of the Stipulating Parties.

Calculation of Revenue Requirement

Pursuant to Section III, Paragraph B of the Stipulation, the Stipulating Parties agree upon the decrease in the calculation of the revenue requirement in the amount of $3,543 based on Company amounts [Line 2].

Termination of Updates after March 31, 2020 Update Period

Pursuant to Section III, Paragraph D of the Stipulation, the Stipulating Parties agree that Aqua NC will not include in the rates to be set in this proceeding the 11 post-test year projects

[1] The Stipulation filed on July 1, 2020, including Settlement Exhibit I to the Stipulation, is incorporated herein by reference. Line references are to Settlement Exhibit I to the Stipulation.

completed after the close of the March 31, 2020 Update Period [Line 5], subject to the following conditions: (1) rates will be set in this proceeding based upon Aqua NC's actual allocated test year costs for Aqua NC Corporate Services and Aqua NC Customer Operations and (2) the Public Staff will not oppose the Company's right to recover the reasonable and prudent costs of the 11 post March 31, 2020 projects in the Company's next rate case or, in the interim, to file a WSIC/SSIC application to recover the costs of any of the post-March 31, 2020 projects which qualify as eligible projects through a surcharge under N.C.G.S. § 62-133.12. The Stipulating Parties agree to the total dollar adjustment on Line 5.

Plant in Service and Accumulated Depreciation Adjustments Related to Reallocation of Vehicles and Post-Test Year Additions

Public Staff witness Henry states that the majority of the vehicles purchased by Aqua NC during the test period were placed into service in the Aqua NC Water Rate Division although such vehicles are also used to provide utility service in Aqua NC's other rate entities. He updated plant in service along with accumulated depreciation and depreciation expense through March 31, 2020, and then allocated the purchase price of these vehicles, along with the applicable accumulated depreciation and depreciation expense among the various Aqua NC rate entities using the customer allocation percentages calculated by the Company.

Pursuant to Section III, Paragraph E of the Stipulation, the Company accepts the Public Staff's proposed adjustment to reallocate vehicles and accumulated depreciation related to those vehicles as set forth in the testimony of Public Staff witness Henry [Line 6]. Pursuant to Section III, Paragraph H of the Stipulation, the Company accepts the Public Staff's proposed adjustment to accumulated depreciation related to vehicle allocations [Line 9].

Pursuant to Section III, Paragraph F of the Stipulation, the Company accepts the Public Staff's proposed adjustment to post-test year additions to accumulated depreciation which results in an increase of $96,683 to revenue requirement [Line 7]. Following the filing of its testimony on May 26, 2020, the Public Staff made corrections to its original position for this adjustment. The Company accepted the Public Staff's adjustment, as corrected. This does not include post-test year additions after March 31, 2020.

Accumulated Depreciation Related to Future Customers

Pursuant to Section III, Paragraph G of the Stipulation, the Company accepts the Public Staff's proposed adjustment to remove accumulated depreciation related to future customers as set forth in the testimony of Public Staff witness Henry [Line 8].

Accumulated Depreciation for WSIC/SSIC "In Service" Date

Witness Henry states that accumulated depreciation has been adjusted for plant additions that were reclassified by the Public Staff from 2019 additions to 2018 additions in Aqua NC's May 1, 2019, WSIC/SSIC application. Witness Henry explains that there were several construction projects booked to plant in service in the first quarter of 2019 that were actually completed and placed into service in 2018. He further explains that these projects were reclassified to the appropriate months in 2018 in the WSIC/SSIC proceeding, which in effect increases the amount of accumulated depreciation calculated on Aqua NC's investment in each project item. He adjusted accumulated depreciation to include an additional amount of accumulated depreciation that should have been recorded on the Company's books based on the change in the in-service dates.

Pursuant to Section III, Paragraph I of the Stipulation, the Company accepts the Public Staff's proposed adjustment to accumulated depreciation for the WSIC/SSIC in service date which resuls in a decrease of $4,455 to revenue requirement [Line 10]. Following the filing of its testimony on May 26, 2020, the Public Staff made corrections to its original position for this adjustment. The Company accepted the Public Staff's adjustment, as corrected.

As discussed in further detail hereinbelow, the Commission finds it appropriate to approve the Stipulation on the adjustment to accumulated depreciation for the WSIC/SSIC in service date in this proceeding, and, therefore, only for the purposes of this rate case proceeding, the Public Staff's adjustment, as corrected, should be reflected.

Post-Test Year Additions to Contributions in Aid of Construction (CIAC)

Pursuant to Section III, Paragraph J of the Stipulation, the Company accepts the Public Staff's proposed adjustment to post-test year additions to CIAC [Line 11].

Post-Test Year Additions to Accumulated Amortization

Pursuant to Section III, Paragraph K of the Stipulation, the Company accepts the Public Staff's proposed adjustment to post-test year additions to accumulated amortization – CIAC [Line 12]. Following the filing of its testimony on May 26, 2020, the Public Staff made corrections to its original position for this adjustment. The Company accepted the Public Staff's adjustment, as corrected.

Post-Test Year Additions Purchase Acquisition Adjustments (PAA).

Pursuant to Section III, Paragraph L of the Stipulation, the Company accepts the Public Staff's proposed adjustment to post-test year additions PAA [Line 13].

Mid-Sauth Growth Related PAA

Pursuant to Section III, Paragraph M of the Stipulation, the Company accepts the Public Staff's proposed adjustment for Mid-South growth-related PAA to March 31, 2020 [Lines 7, 10 and 12].

Post-Test Year Additions Accumulated Amortization – PAA

Pursuant to Section III, Paragraph N of the Stipulation, the Company accepts the Public Staff's proposed adjustment to post-test year additions accumulated amortization – PAA [Line 15].

Advances for Construction

Pursuant to Section III, Paragraph O of the Stipulation, the Company accepts the Public Staff's proposed adjustment to update advances for construction to March 31, 2020 [Line 16].

ADIT – Post-Test Year Additions

Pursuant to Section III, Paragraph P of the Stipulation, the Company accepts the Public Staff's proposed adjustment to ADIT – post-test year additions [Line 17]. This does not include post-test year additions after March 31, 2020.

ADIT – Unamortized Rate Case Expense

Pursuant to Section III, Paragraph Q of the Stipulation, the Company accepts the Public Staff's proposed adjustment to ADIT - unamortized rate case expense [Line 18].

Accumulated Deferred Income Tax (ADIT) – Unamortized Repair Tax Credit

Pursuant to Section III, Paragraph R of the Stipulation, the Company accepts the Public Staff's proposed adjustment to Adjustment to ADIT - unamortized repair tax credit [Line 19].

ADIT – Protected Excess Deferred Income Tax and Amortized Excess Deferred Income Tax (EDIT)

The Commission addressed the appropriate regulatory treatment for the Federal Tax Cuts and Jobs Act (the Tax Act) and State corporate income tax issues for Aqua NC in the Company's last general rate case (Sub 497). In the Sub 497 docket, Aqua NC and the Public Staff stipulated to all the Tax Act and State EDIT issues, and the Commission approved the Stipulation, which included the following:

- The Company's federal protected EDIT would 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);

- The Company's federal unprotected EDIT would be returned to ratepayers through a levelized rider over a period of three years beginning in January 2019 and ending in December 2021;

- The Company's provisional revenues (which represent the over-collection of federal income taxes in rates related to the decrease in the federal corporate income tax rate from 35.00% to 21.00% for the period beginning January 1, 2018, and corresponding interest, based on the overall weighted cost of capital) would be refunded to ratepayers as a bill credit for a one-year period beginning in January 2019 and ending in December 2019; and

- 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 would be returned to ratepayers through a levelized rider over a three year period beginning in January 2019 and ending in December 2021.

In this proceeding, Aqua NC did not address the issue in its direct testimony since all the tax issues were decided in Sub 497. The Public Staff notes in its direct testimony that Aqua NC did not include the flowback of federal protected EDIT in determining the calculation of its proposed revenue requirement. Specifically, Public Staff witness Boswell recommends in her direct testimony an adjustment to include the return of protected federal EDIT based upon the Company's calculation of the net remaining life of the timing differences, utilizing the Company's current composite tax rate to calculate the annual amortization, net of tax, to be flowed back to ratepayers. Aqua NC witness Gearhart notes in his rebuttal testimony that the Company agrees with the Public Staff's adjustment, therefore Aqua NC and the Public Staff have fully agreed on the treatment of the tax issues in this proceeding. This agreement is outlined in the Stipulation.

During the expert witness hearing, Aqua NC witness Gearhart confirmed in response to questions from Commissioner Brown-Bland that the federal unprotected EDIT rider and the state EDIT rider that were approved by the Commission in the Company's last rate case continue to be flowed back by Aqua NC to customers as riders as was ordered in Sub 497. He further explained that those refunds have been going on since the beginning of 2019 and that as of June 2020, Aqua NC is halfway through the three-year refund period. Witness Gearhart also confirmed that Aqua NC's customers received the full amount of the provisional revenues through the one-year bill credit that the Commission approved in Sub 497. He explained that Aqua NC had a refund target of $1.641 million to be refunded during the calendar year 2019. He noted that Aqua NC actually refunded slightly higher than that amount. Witness Gearhart stated that Aqua NC carried over the refund process slightly into 2020, but that Aqua NC actually refunded about $6,000 more than the original target. Tr. vol. 3, 156-157.

As outlined in Section III, Paragraphs S and FFF of the Stipulation, Aqua NC accepts the Public Staff's proposed adjustment to ADIT - protected EDIT [Line 20]. Further, the Company accepts the Public Staff's proposed adjustment to amortized Excess Deferred Income Taxes (EDIT) [Line 64]. Based on the record, the Commission finds it appropriate to accept the Public Staff and Aqua NC's agreements on this issue.

Customer Deposit Update

Pursuant to Section III, Paragraph T of the Stipulation, the Company accepts the Public Staff's proposed adjustment to update customer deposits to March 31, 2020 [Line 21].

Excess Capacity Ratemaking Adjustment

Aqua NC witness Becker states in his direct testimony that Aqua NC did not include an adjustment in its rate case application for excess capacity. He asserts that the Commission should not impose excess capacity disallowances for systems that the Company has acquired or installed.

Witness Becker contends that the decisions to construct the three plants for which disallowances have been made in the past were prudent and reasonable, the plants were properly sized, and Aqua NC's investments in these plants on a per connection basis are reasonable. Witness Becker argues that to require Aqua NC to absorb depreciation expense without recovery through rates is inconsistent with the Commission's policy encouraging acquisition of developer owned systems and uniform rates.

Witness Becker states that Aqua NC's system includes 59 wastewater treatment plants (WWTPs) that were acquired through purchases or developer contracts. He contends that these acquisitions have resulted in a reasonable range of average rate base per customer by system and that the resultant consolidated rate bases and capital costs are reasonable.

Public Staff witness Junis states in his direct testimony that Aqua NC did not include any excess sewer plant capacity adjustments in its Application; he further states that this is inconsistent with the Company's previous rate cases going back at least to the Sub 274 rate case in 2009. He explains that the excess capacity adjustment removes a percentage of the plant and accumulated depreciation from the rate base. Witness Junis explains that he does not recommend excess capacity adjustments for all of Aqua NC's overbuilt WWTPs. He offers the example of the Cannonsgate plant which has a calculated overbuilt capacity of 88.80%. No excess capacity adjustment for Cannonsgate is recommended by the Public Staff because the initial construction was fully contributed by the developer. Witness Junis maintains that Aqua NC has assumed avoidable cost and risk from developers in some of its other systems. He states that without an excess capacity adjustment the existing customers will pay a disproportionate and unfair portion of excess plant to serve future customers.

Witness Junis states that the Commission is open to consideration of other calculation methods. He points to the Commission's statement in Aqua NC's Sub 497 Rate Order requesting more evidence from the parties to support other formulas or methods. In response, witness Junis states that he has considered a formula that is more consistent with North Carolina Department of Environmental Quality (DEQ) regulations; however, using this formula would net the exact same adjustment percentages. For this reason, witness Junis recommends that the Commission continue to use the calculation method established by the Commission in Docket No. W-218, Sub 319, for evaluating the used and useful portions of WWTPs. He states that Aqua NC has used this method in its last three general rate cases.

Witness Junis states that he calculated the excess capacity for the Carolina Meadows, The Legacy at Jordan Lake, and Westfall (also known as Booth Mountain) WWTPs to be 33.03%, 19.67%, and 18.44%, respectively. Witness Junis further contends that Aqua NC has failed to meet its burden of persuasion by not including evidence to justify the omission of excess capacity adjustments. Therefore, witness Junis recommends that the entire balance of plant be subjected to the excess capacity adjustments that he calculates and presents in his testimony. He notes that Public Staff witness Henry has implemented the updated excess capacity percentages and plant, net of accumulated depreciation and contributions in aid of construction (CIAC), to calculate the excess capacity adjustment.

Witness Henry describes his adjustments for excess capacity and notes that Aqua NC did not make an excess capacity adjustment to the three WWTPs (specifically, Carolina Meadows, The Legacy at Jordan Lake, and Westfall Subdivision) as was approved by the Commission in the Sub 497 rate case. Witness Henry explains that he started with the plant balances in the Sub 497 rate case to which he added plant additions and removed retirements according to the Company's books since the Sub 497 rate case. He next added back 50% of the Carolina Meadows WWTP additions that were removed in the Sub 497 rate case based on the recommendation of witness Junis. He then depreciated the updated plant in service through March 31, 2020. Finally, he applied witness Junis' recommended excess capacity percentages of 33.03%, 19.67%, and 18.44% for the Carolina Meadows, The Legacy at Jordan Lake, and Westfall WWTPs, respectively, to remove the disallowed portions of plant in service, accumulated depreciation, and CIAC.

Aqua NC witnesses Becker and Pearce provided joint rebuttal testimony on this issue to emphasize important accounting and engineering differences that they find in witness Junis' testimony. Witness Becker addresses key accounting differences while witness Pearce provides a detailed description of the engineering differences with the Public Staff's recommendations.

Witness Becker describes excess capacity as the difference between treatment plant design flow and customer contributory design flows and states there is a significant issue with witness Junis' application of excess capacity adjustments for capital expenses necessary for the continuing compliance for the existing customers of these facilities. Witness Becker points out witness Junis' statement that "the developer of a system bears a majority of the initial cost and risk associated with plant infrastructure to serve future projected growth." Witness Becker contends therefore that any post-acquisition capital costs to ensure compliance should be fully recoverable. Witness Becker contends that application of excess capacity to post-acquisition capital penalizes the Company for continuing to service its customers responsibly and serves as a disincentive to investing in necessary repairs, replacements, and upgrades because the Company knows that a percentage of that cost will be unrecoverable. He refers to the 50% excess capacity adjustment applied to the Carolina Meadows upgrades ($1.7 million total) in Aqua NC's last rate case and contends that this effectively resulted in an investment exceeding $250,000 that will never be recovered assuming excess capacity adjustments continue to be allowed and are applied to post-acquisition investments. Witness Becker argues that there are no excess capacity disallowances for developer-installed systems acquired at original costs. He contends that the decisions to construct the plants were reasonable and prudent, the WWTPs were designed according to state standards, and Aqua NC was prudent when it acquired them. He also contends that requiring Aqua NC to take depreciation on its books without actual recovery of the expense is inconsistent with the Commission's policy of encouraging acquisition of developer-owned systems and application of a uniform rate structure. He states that this approach is also a barrier to Aqua NC's opportunity to earn its authorized return.

Witness Becker states that Aqua NC's statewide wastewater system is comprised of 59 WWTPs and divided into two consolidated rate divisions. He notes that the plants were acquired through acquisition or developer contracts and resulted in a footprint of assets and costs per customer that are arranged in two consolidated rate divisions. Witness Becker maintains that Aqua NC Sewer is a consolidated rate division that contains three WWTPs (specifically, Carolina Meadows, The Legacy, and Westfall plants) that have received excess capacity treatment in the past. Witness Becker argues that the elimination of rate base costs for these three WWTPs because reasonably anticipated, planned growth has not occurred in these service areas is inappropriate. Witness Becker states that if excess capacity adjustments are nevertheless determined to be appropriate, then the adjustments should not be applied to post-acquisition repairs, replacements, and upgrades. Witness Becker refers to Aqua NC's Sub 497 Order that states in part that all investments in WWTPs is consolidated into the plant in service account and designations for individual plants are lost for ratemaking purposes.

Witness Becker provides a review of the test year capital expenditures for Carolina Meadows, The Legacy, and Westfall including a breakout of plant expenditures and other infrastructure repairs, replacements, and upgrades necessary to maintain compliance of the systems. He notes that total capital charges for Carolina Meadows were $216,478 of which $72,965 or 38% was spent on the plant. He states that, similarly, the total plant capital expenditures for The Legacy and Westfall were both 38% with the remaining 62% going towards system infrastructure repairs, replacements, and upgrades. Witness Becker argues that it is not proper to reduce rate base capital for expenditures that are not for the treatment plant itself.

Witness Pearce disagrees with witness Junis' method for calculating the design flows for the Carolina Meadows, The Legacy, and Westfall WWTPs and offers an alternative calculation methodology. He contends that his alternative method is more appropriate and that it is consistent with North Carolina design guidelines for wastewater systems established by DEQ in the North Carolina Administrative Code (NCAC).

Witness Pearce contends that the Public Staff has incorrectly calculated the contributory design flow component of the excess capacity calculation resulting in a flawed estimate of excess capacity for the three WWTPs in question. More specifically witness Pearce contends that witness Junis' use of residential equivalency units (REUs) and a generalized estimate of gallons needed to support each REU to calculate contributory design flow is flawed. He states that WWTPs are designed for maximum flow potential based on designed bedrooms per dwelling unit, not REUs. Witness Pearce states that WWTPs are designed to handle the maximum flows for the types of buildings proposed in the development. Witness Pearce contends that the use of REUs and a generalized estimate of 400 gallons per day for each REU results in an overestimation of excess capacity for which the plant was properly designed according to the regulations for design flow in 15A NCAC 02T.0114 - Wastewater Design Flow Rates. Witness Pearce argues that determining contributory design flow based on this code illustrates that the three WWTPs in question should have no excess capacity adjustments.

Witness Pearce further states that witness Junis inaccurately references the Commission's ruling in the Sub 497 Order as the basis for continuing to use the Public Staff's REUs method for calculating excess capacity in this rate case. He states that the Commission instead requested that Aqua NC and the parties present alternative calculation methods if the issue came up in future rate cases. Witness Pearce presents an alternative that replaces the use of REUs and approximation of gallons per day with the metric that is used to size WWTPs.

Witness Pearce opines that the use of water meter size is a poor estimate of contributory wastewater design flow because water meter sizing calculations do not properly estimate the number of bedrooms per residence. He adds that REUs are also a poor approximation for commercial facilities. Witness Pearce points to witness Junis' data request response in which witness Junis references 15A NCAC 18C.0409 – Service Connections[1] as the basis for the water design standard of 400 gallons per connection for a residential service. Witness Pearce notes that the 15A NCAC 18C.0409 regulations are water supply design regulations and that the wastewater treatment design regulations are contained in 15A NCAC 02T.0114 – Wastewater Design Flow Rates[2] and they are not equivalent.

Witness Pearce discusses how the determination of excess capacity should be based on the same understanding that was used to design the plant. He notes that the regulations in 15A NCAC 02T.0114 provide prescriptive requirements for plant design such as a 120 gallon per day per bedroom requirement for residential with a 240 gallon per day minimum for each dwelling unit. He states that the code also provides gallon per day values for various commercial uses. He notes that for a residential example, a standard 5/8" meter is typically installed to provide water to the residence. He states that the REU calculation method in this case would result in a 400 gallon per day contributory flow regardless of the size of the home. He explains that if instead the developer planned this as a five-bedroom home the contributory flow would be calculated as 600 gallons per day using the prescriptive 120 gallon per bedroom per day from the wastewater treatment design calculations.

Witness Pearce provides a review of the calculations that Aqua NC prepared for Carolina Meadows, The Legacy, and Westfall that show a contributary design flow that exceeds the design capacity of each plant when calculated using the previously referenced wastewater design regulations from 15A NCAC 02T.0114. The total calculated revenue reduction proposed by the Public Staff is approximately $190,000 annually using the Public Staff's REUs and approximate gallons per day method, whereas using the Company's recommended calculation method results in no adjustment. Witness Pearce argues that reliance on the REUs does not consistently allow for an accurate representation of the number of bedrooms per residence and REUs are a poor approximation for commercial facilities. In his discussion of the actual contributory design flow for the Carolina Meadows Senior Care facility, witness Pearce asserts that the misapplication of REUs in witness Junis' calculations resulted in a 100,000 gallon per day error that when added to the contributory design flow calculations for the Carolina Meadows plant clearly demonstrates that the WWTP is near design flow capacity. Another example offered by witness Pearce describes where a facility's REU count was based on a 6-inch wastewater meter resulting in a REU count of 50 whereas a review of water billing data indicates a total of 278 active accounts.

Witness Pearce recommends that no excess capacity adjustments should be made for Carolina Meadows, The Legacy, or Westfall WWTPs because the existing or approaching design flows when calculated according to the NCAC for wastewater systems are greater than the permitted capacities for the WWTPs, and witness Becker concurs.

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1 http://reports.oah.state.nc.us/ncac/title%2015a%20-%20environmental%20quality/chapter%2018%20-%20environmental%20health/subchapter%20c/15a%20ncac%2018c%20.0409.pdf

2 http://reports.oah.state.nc.us/ncac/title%2015a%20-%20environmental%20quality/chapter%2002%20-%20environmental%20management/subchapter%20t/15a%20ncac%2002t%20.0114.pdf

WATER AND SEWER – RATE INCREASE

As outlined in Section III, Paragraph U of the Stipulation, the stipulating parties agree that no excess capacity ratemaking adjustment should be made in this rate case related to Aqua NC's wastewater treatment plants which serve the Company's Carolina Meadows, The Legacy, and Westfall service areas [Line 22].

During the expert witness hearing, Public Staff witness Junis stated during his Summary that as part of the give and take of compromise in settlement negotiations, the stipulating parties agreed that no excess capacity adjustment be made in this rate case. Witness Junis noted that the Public Staff is reserving the right to evaluate and recommend excess capacity adjustments as it deems appropriate in future rate cases. Tr. vol. 5, 70.

Also, during the expert witness hearing, Commissioner Clodfelter asked the Public Staff Panel of witnesses Henry and Junis a question about the Stipulation in this case. Commissioner Clodfelter noted that in the Public Staff's original prefiled testimony, there was a proposed excess capacity adjustment for the three wastewater treatment plants that were also the subject of an excess capacity adjustment in Sub 497. Commissioner Clodfelter observed that that proposed adjustment has been withdrawn as outlined in the Stipulation and inquired about what led to that result. Commissioner Clodfelter specifically asked the Panel whether the Public Staff has accepted the Company's position with respect to the methodology for calculating whether or not there is excess capacity with respect to those plants. Witness Junis explained in response to the question that the Stipulation clearly says that the Public Staff reserves the right to take a different position (on any of the issues included in the Stipulation) in future rate cases. When further questioned about why the Public Staff withdrew its position on excess capacity in this case, witness Junis expressed that the withdrawal was a byproduct of give-and-take within the settlement and that the excess capacity was a give and there was take that was also tied to it. Witness Junis agreed that Commissioner Clodfelter should not conclude that the Public Staff has now agreed with the Company's methodology for calculating excess capacity. Tr. vol. 4, 340-341.

The Commission notes that there has been an evolving history on excess capacity adjustments for Aqua NC dating back to at least the Docket No. W-218, Sub 274 rate case in 2009. The Commission has stated the following in past rate cases concerning excess capacity adjustments:

Docket No. W-218, Sub 319 – November 3, 2011 Order Granting Partial Rate Increase, page 30:

> In the past the Commission has employed a variety of formulas and methods for making excess capacity adjustments. In this case the only one proposed is the one advocated by Public Staff witness Furr[1]. For reasons stated herein the Commission has used a different calculation[2]. Unfortunately Aqua NC presented no evidence

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[1] Witness Furr calculated the percent of excess capacity as follows: Percent Excess Capacity = 100 – ((high average monthly flow/90% of plant capacity installed) x 100).

[2] The Commission concluded that the determination of excess capacity should be based upon the number of end-of-period REUs using the standard of 400 gpd per connection which was consistent with the standard outlined in the Commission's June 10, 1994 Order in Docket No. W-354, Sub 128.

> as to what, in its view, a reasonable method for making an excess capacity adjustment should be. Should this issue arise in future cases, the Commission could benefit from more evidence from Aqua NC on this point.

Docket No. W-218, Sub 497 – December 18, 2018 Order Approving Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice, page 48:

> The Commission reminds the parties that in the past the Commission has employed a variety of formulas or methods for making excess capacity adjustments. The Commission notes that the Company did not present any evidence in this proceeding regarding how to appropriately update its excess capacity percentages or whether future growth projections in the applicable service areas as determined by any available definitive growth documentation, such as housing permits issued, should be factored into such calculations. The Commission advises the parties that should this issue arise in a future rate case proceeding, the Commission requests that more evidence be presented by the parties regarding other formulas or methods for making excess capacity adjustments such that the Commission could determine by the weight of the evidence presented whether future growth projections or any other additional factors should be included in the approved methodology.

In the instant proceeding as summarized above, Aqua NC did in fact present an alternative method to evaluate any potential excess capacity through the testimony of witness Pearce. However, ultimately in this docket, Aqua NC and the Public Staff stipulated that no excess capacity adjustment should be made. Public Staff witness Junis expressly clarified that the Public Staff's entering into the Stipulation did not mean it agreed to Aqua NC's methodology for calculating excess capacity.

Although the Stipulating Parties have reached agreement, the Commission expects a fully developed record on this issue in Aqua NC's next general rate case, including a detailed methodology supported by Aqua NC similar in form to the evidence presented by Aqua NC herein and a detailed response from the Public Staff either supporting such a methodology or providing specific counter arguments against the use of such methodology. In addition, if the Public Staff does not agree with Aqua NC's proposed methodology, the Public Staff should provide detailed evidence supporting any excess capacity calculation or methodology the Public Staff recommends that the Commission adopt. In Aqua NC's next general rate case, the Commission expects that either Aqua NC and the Public Staff will reach a consensus on this issue or that the Commission will be in the position to decide this issue after it is fully litigated by the parties. Based on the record in this proceeding, the Commission finds it appropriate to approve the Stipulation on the adjustments related to excess capacity in this proceeding and, therefore, only for the purposes of this proceeding, no excess capacity ratemaking adjustment should be reflected.

Cash Working Capital

Pursuant to Section III, Paragraph V of the Stipulation, the Company accepts the Public Staff's proposed adjustment to cash working capital [Line 23].

Tank Painting

Public Staff witness Henry adjusts the unamortized balances for tank painting for Aqua NC Water, Fairways Water, and Brookwood Water to reflect the balances as of September 30, 2020, the date by which the Public Staff expected a final order to be issued by the Commission. Public Staff Henry Exhibit I, Schedule 2-7, filed on May 26, 2020, sets forth the following amounts on Line 3 for unamortized tank painting balances for Aqua NC Water, Fairways Water, and Brookwood Water: $640,406, $26,911, and $33,695, respectively.

Aqua NC witness Thill disagrees with witness Henry's adjustments to the unamortized balances for tank painting for the Company's three water rate divisions. Witness Thill states that tank painting has been a recognized component of the rate base working capital computation in prior cases and continues to be included in the Public Staff's current proposal. He notes that tank painting occurs on a routine basis and is amortized over a ten-year life. He further notes that the Sub 497 rate case included the full balance of the account in rate base, updated through the end of the post-test year. Witness Thill states that under the Public Staff's current proposal, the Public Staff has modified past practice by amortizing one year of expense from the test-year balance.

Witness Thill notes that one-time working capital components such as rate case expenses do have a year's amortization deducted from the prepaid balance in determining rate base. He explains that the distinction here is that for rate case expenses, the amortizing balance is not increased after the case is completed. He further explains that as time passes, the Company collects reimbursement from customers via the amortization expense component of the revenue requirement, and the prepaid balance reduces accordingly. Witness Thill contends that tank painting is different in that there is a continual requirement for further capital advancement. He notes that in the test year there were $223,900 in expenditures against only $151,100 in amortization expense. Witness Thill states that the Company does not believe the Public Staff's proposed change is appropriate and requests that the Commission reaffirm past practice, eliminating the Public Staff's amortization projection and fixing the rate base balance at the post-test year date. Witness Thill maintains that this treatment would appropriately recognize the cost of an ongoing obligation of the Company to advance capital for this long-term operational expense for the benefit of its customers.

Notwithstanding their opposing contentions, pursuant to Section III, Paragraph W of the Stipulation, the Stipulating Parties agreed on the Public Staff's adjustment for tank painting [Line 24]. Public Staff Henry Exhibit I, Schedule 2-7 Revised 8/17/20, filed on August 17, 2020, sets forth the following amounts on Line 3 for the stipulated amount of unamortized tank painting balances for Aqua NC Water, Fairways Water, and Brookwood Water: $883,382, $26,911, and $245,734, respectively.

Based on the record in this proceeding, the Commission finds it appropriate to approve the Stipulation on the adjustments related to the unamortized balances of tank painting for Aqua NC Water, Fairways Water, and Brookwood Water in this proceeding and, therefore, only for the purposes of this proceeding, the Public Staff's modified method for calculating the unamortized balance of tank painting should be reflected.

Unamortized Rate Case Expense

Public Staff witness Henry states that in this proceeding the Public Staff has reevaluated the past practice of the water or wastewater utility's unamortized rate case expense balance being included in rate base upon which the utility earns a return. He contends that the Public Staff sees no reason for this practice to continue. Moreover, the Public Staff recommends in this rate case proceeding and all future water or wastewater utility general rate cases that the unamortized rate case expense balance not be included in rate base with the utility earning a return. Witness Henry explains that the unamortized balance would continue to be amortized in the Commission-approved revenue requirement, thereby allowing the Company recovery of the expenses, but not allowing the utility to earn a profit on the rate case expenses.

Witness Henry maintains that this change will provide Commission regulated water or wastewater utilities the same rate case expense treatment as the Commission regulated electric and natural gas utilities which do not earn a return on their unamortized rate case expense balances. Witness Henry states that the customers will pay the Company's rate case expenses, but contends that it is unreasonable for customers to pay the utility a return on equity for regularly occurring expenses that by their nature and magnitude should just be normalized, not treated as a regulatory asset.

Aqua NC witness Thill disagrees with the Public Staff's adjustment to exclude the unamortized rate case expense balances from the working capital component of rate base. Witness Thill first discusses his rationale for including working capital as a component of rate base. He states that the courts have opined, and the Commission has operated in a manner consistent with the philosophy, that "[t]o fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking". He further states that past Orders of the Commission provide extensive defense of this position and are therefore not recounted in his rebuttal testimony. Witness Thill maintains that a utility is entitled to a fair return on all its property prudently employed for the benefit of its customers. He explains that property, in this context, includes not just utility plant, but also any funds provided by shareholders on behalf of customers. He states that such funds are loosely termed in this circumstance as working capital. He notes that this rationale has been consistently applied in the Company's prior rate cases.

Witness Thill states that, as a firm rule, Aqua NC is against providing interest-free loans. He asserts that to do so willingly would be an imprudent use of shareholder funds, and to be forced to do so would seem to violate the previously quoted Court opinion regarding "unconstitutional taking." Witness Thill notes that witness Henry contends that the Company should not be allowed to "earn a profit on the rate case expenses". Witness Thill contends that inclusion of rate case expenses in rate base is not the equivalent of earning a profit. He maintains that the courts have held that a utility is allowed "to recover its costs, including the cost of equity capital". Witness Thill further maintains that only after consideration of this cost of capital can "profit" be determined. Witness Thill asserts that the Company has already advanced significant sums in support of this rate case and will continue to do so without recovery or return until the Commission's final order. He notes that when recovery does begin, even if the Commission were to hold consistent with prior practice, the Company would still only recover its cost of funds on two-thirds of the balance (assuming a three-year amortization period) due to the Public Staff's standard practice of rolling the balance forward a full year resulting in deduction of one year's amortization from cost of capital recovery in rate base. Witness Thill states that it is the Company's position that where the Company's prudent expenditures are not timely offset by recovery in rates, the cost of capital must be recognized in the rate base calculation.

In summary, witness Thill maintains that the inclusion of working capital in rate base is a recognition of the cost of capital prudently employed by the utility for the benefit of its customers. He contends that the courts have long held that a utility is entitled to a fair return on all such property, and the Company submits that obtaining a fair return on that property is an important element in providing the Company with a reasonable opportunity to achieve its authorized return.

Pursuant to Section III, Paragraph X of the Stipulation, the Company accepts the Public Staff's adjustment to unamortized rate case expense [Line 25]. Public Staff Henry Exhibit I, Schedule 2-7 Revised 8/17/20, filed on August 17, 2020, sets forth the following amounts on Line 4 for the stipulated amount of unamortized rate case expense balances related to the Sub 497 rate case proceeding for Aqua NC Water, Aqua NC Sewer, Fairways Water, Fairways Sewer, and Brookwood Water: $173,674, $45,858, $13,254, $8,445, and $38,392, respectively, included in the working capital component of rate base in this proceeding. As stipulated, such amounts do not include the unamortized balance of rate case expense related to the present proceeding.

Based on the record in this proceeding, the Commission finds it appropriate to approve the Stipulation on the adjustment related to the unamortized balance of rate case expense in this proceeding and, therefore, only for the purposes of this proceeding, the unamortized balance of rate case expense for the Sub 497 rate case proceeding should be included in the working capital component of rate base and the unamortized balance of rate case expense related to the current proceeding should not be so included.

Depreciation Study

Pursuant to Section III, Paragraph Y of the Stipulation, the Company accepts the Public Staff's proposed adjustment to depreciation study [Line 26]. Public Staff Henry Exhibit I, Schedule 2-7 Revised 8/17/20, filed on August 17, 2020, sets forth the following amounts on Line 5 for the stipulated amount of unamortized depreciation study balance for Aqua NC Water, Aqua NC Sewer, Fairways Water, Fairways Sewer, and Brookwood Water: $23,678, $5,929, $1,694, $1,078, and $5,313, respectively, included in the working capital component of rate base in this proceeding.

Repair Tax Credit

Pursuant to Section III, Paragraph Z of the Stipulation, the Company accepts the Public Staff's proposed adjustment to repair tax credit [Line 27]. Public Staff Henry Exhibit I, Schedule 2-7 Revised 8/17/20, filed on August 17, 2020, sets forth the following amounts on Line 6 for the stipulated amount of unamortized repair tax credit balance for Aqua NC Water, Aqua NC Sewer, Fairways Water, Fairways Sewer, and Brookwood Water: $64,711, $20,701, $1,630, $1,793, and $10,269, respectively, included in the working capital component of rate base in this proceeding.

Johnston County Unamortized Transmission Charge

Pursuant to Section III, Paragraph AA of the Stipulation, the Company accepts the Public Staff adjustments to remove the Johnston County unamortized transmission charge and revenue deficit [Lines 28 and 29], consistent with the Commission's decision in the Sub 497 rate case.

Deferred Accounting on Post-Test Year Plan Additions

In its application Aqua NC requests authorization to defer costs related to capital projects expected to be placed in service during the post-test year period. Aqua NC witness Thill testifies that Aqua NC proposed to defer carrying costs and depreciation on these post-test year projects from the individual project's in-service date until the projects are included for recovery in base rates in the Sub 526 proceeding. Witness Thill states that the deferred balance would be recorded as a regulatory asset, included in rate base and amortized over five years in this rate case.

Witness Thill states that Aqua NC requested authorization to defer carrying costs and depreciation on 246 projects identified for completion during the six months comprising the presumed post-test year period at a cost of $13.8 million, which he calculated to be an average per project cost of approximately $56,000. Witness Thill notes that Aqua NC excluded from its deferral request approximately $7.0 million in anticipated post-test year capital expenditures that Aqua NC has deemed to be routine replacements.

Witness Thill maintains that the impact of the costs, if not deferred, on the Company's authorized rate of return on common equity approved in the Sub 497 rate case will be significant and material. Witness Thill calculates that implementing these projects will create a drag of 68 basis points on Aqua NC's rate of return on common equity compared to that which was authorized in the Sub 497 rate case. *See* Thill Direct Exhibit 5 for the calculation of the 68 basis points.

In support of the Company's request, witness Thill testified that the Commission has considered in its past decisions the collective financial impact of various types of projects when determining whether to grant deferral accounting authorization. He states that, for example, in a 2009 Duke Energy Carolinas case, the Commission authorized the utility to use deferral accounting for both environmental compliance costs and the purchase of a portion of the Catawba Nuclear Station. *See* In the Matter of Petition of Duke Energy Carolinas, Docket No. E-7, Sub 874 (NCUC; Mar. 31, 2009). Witness Thill notes that in another deferral accounting case, the Commission granted deferral accounting treatment for plant additions (the Buck and Bridgewater generation additions) that were projected to produce rate of return on common equity reductions in the absence of deferral accounting treatment. *See* In the Matter of Duke Energy Carolinas, Docket No. E-7, Sub 999 (NCUC; June 20, 2012).

Witness Thill testifies that the Commission required in DEC Sub 874 case "... a clear and convincing showing that the costs in question were of an unusual and/or extraordinary nature and that, absent deferral, [the costs] would have a material impact on the Company's financial condition." Witness Thill states that Aqua NC's footprint consists of more than 740 developer built, stand-alone systems that require the operation of over 1,400 wells and 59 wastewater plants across the state. He contends that the dispersed nature of Aqua NC's operations is very different than many peers in the electric and gas utility industries in North Carolina, as the majority of water and wastewater systems operated by the Company are autonomous and self-reliant units that typically provide water production and treatment to serve the customers within the confines of that system. Witness Thill maintains that the sheer magnitude of the independent facilities that make up the Company's operational footprint necessitates that the Company's capital spending be divided into hundreds of smaller projects rather than a few large ones.

Witness Thill argues that the total financial impact of this spending on the utility is indifferent to the number of projects that comprise that total spending. He asserts that from the customer's perspective, there is a better argument to recognize the benefit of a multitude of projects impacting a larger share of the customer base rather than individually large projects with a more limited customer impact.

Witness Thill testifies that in this proceeding Aqua NC argues for use of deferral accounting by the Commission as a legitimate tool, accompanied by safeguards, to help avoid degradation of the Company's ability to earn its authorized rate of return on common equity and reduce the resultant increasing frequency of filings for rate relief. Witness Thill contends that to be an effective regulatory tool for the water and wastewater industries, supporting the legitimate goals of full and timely recovery of prudent, necessary expenditures made for the purpose of providing quality service to customers, the application of deferral accounting must include the ability to aggregate expenditures, as the Commission considers a determination of materiality. He states that this is particularly true if this tool is to apply as effectively to the water and wastewater industry as it does to the electric and natural gas industries, due to the different characteristics of these industries.

Witness Thill states that while the WSIC and SSIC mechanisms do provide a meaningful level of regulatory lag relief between rate cases, the limitations of the cap and on eligible items, combined with the regulatory lag that exists even within those mechanisms, still leave a material hole in the Company's ability to earn its authorized rate of return. He notes that of the Company's $20.8 million of projected post-test year additions, only $6.8 million represent WSIC/SSIC eligible projects.

Witness Thill proposes to defer depreciation and accrue carrying costs for qualifying capital expenditures for the time beginning with the individual in-service dates through implementation of new base rates. The deferred balance would be recorded as a regulatory asset, included in rate base and amortized over five years in this rate case. In calculating the deferral amount, depreciation is calculated using Aqua NC's depreciation rates for each asset class as computed in its most recent depreciation study and as approved in its prior rate case. The calculation of carrying costs uses the blended debt/equity rate of 7.165% authorized in Aqua NC's most recent rate case (Sub 497).

Witness Thill states that Aqua NC has also requested "prospective authorization" to defer depreciation and carrying costs on post rate case capital expenditures, other than routine replacements, until included in rates in Aqua NC's next rate case. He states that this request, if approved, would significantly improve the Company's ability to attain its authorized rate of return on common equity and resultantly extend the current anticipated time needed between rate case filings.

Public Staff witnesses Henry and Junis maintain that deferral accounting treatment is a special ratemaking treatment that the Commission has allowed sparingly and only based upon specific criteria. They cite the following Commission Orders in their testimony as examples of Commission's conclusions and decisions concerning deferral accounting requests: Docket Nos. E-7, Sub 874; E-7, Sub 1023; and the recent Carolina Water Services, Inc. of North Carolina (CWSNC) rate case order issued March 31, 2020 in Docket No. W-354, Sub 364. Witnesses Henry and Junis state that the Commission has required "a clear and convincing showing that the costs in question were of an unusual and/or extraordinary nature and that, absent deferral, would have a material impact on the Company's financial condition". DEC Sub 874 Order at 25.

Witnesses Henry and Junis state that Aqua NC admitted in response to Public Staff Data Request No. 84 (*See* Henry and Junis Exhibit 6), that on an individual basis, none of the costs included in Company's request for deferral accounting treatment are unusual or extraordinary. They state that Aqua NC also admitted in response to that same data request that on an individual basis, none of the costs included in the Company's request for deferral accounting treatment are of a magnitude that would result in a material impact on the Company's financial position.

Witnesses Henry and Junis maintain that the Company's request is premised on the novel argument that the projects and related costs for which Aqua NC seeks deferral accounting treatment should be considered not on an individual basis, but in the aggregate. They note that witness Thill contended when comparing Aqua NC's facilities to those of the state's electric and gas utilities, "[t]he sheer magnitude of the independent facilities that make up the Company's operational footprint necessitates that the Company's capital spending be divided into hundreds of smaller projects rather than a few large ones". Witnesses Henry and Junis assert that witness Thill's contention is false and based on an overly simplified comparison. They maintain that while the electric industry has a limited number of electric generating plants, those plant sites are a complex system of smaller capital assets serving different purposes, such as steam generation, fuel storage, environmental controls, waste management, and safety, in support of providing sufficient and reliable service.

Witnesses Henry and Junis state that, consistent with direction provided by the Commission in its prior decisions on requests for deferral accounting treatment, they assessed the Company's deferral request in the present case by examining whether the Company made a clear and convincing showing that the costs in question are of an unusual or extraordinary nature and would have a material impact on the Company's financial condition absent deferral. According to witnesses Henry and Junis, the Company admitted that its deferral request does not meet this test when the costs in question are considered on an individual basis. However, witnesses Henry and Junis did not stop there, but also evaluated the Company's deferral request based on its aggregated capital expenditures in response to the novel argument advanced by Aqua NC. They maintain that their evaluation of the Company's deferral request based on the aggregate of the projects and costs at issue should not be interpreted by the Commission as endorsement of the Company's novel argument, but instead as a thorough investigation of the Company's proposal.

Witness Junis reviewed the aggregated projects and capital costs characterized by the Company as being "non-routine" to determine whether they were "unusual" or "extraordinary" in nature and outside the scope of Aqua NC's normal course of business. Witness Henry assessed whether the magnitude and impact of the aggregated costs justified deferral, including the impact on earnings, current economic conditions, the Company's need for new investment capital, and the impact that the Commission decision will have on future availability and cost of such capital.

Witnesses Henry and Junis reviewed Aqua NC's recent capital investment history in North Carolina and noted that Aqua NC's capital spending was consistently $12-14 million per year from 2011 through 2014, that it incrementally increased in 2015 and again in 2016, and that beginning in 2017 it reached a level of $36-40 million per year, which they state the Company plans to maintain at least through 2021. Witnesses Henry and Junis summarize various observations regarding their review of Aqua NC's plant additions over the past several years including (1) blanket or routine replacements steadily increased by over $2 million annually from 2015 through 2018, since plateauing in the range of $11-12 million and being fairly consistently distributed among the rate entities; (2) non-routine, non-WISC/SSIC spending steadily increased by 30% annually from 2015 through 2017, ballooned into the Sub 497 rate case, and then appear to have returned to the previous upward trajectory in 2019; (3) the WSIC was heavily utilized between rate cases and in the Aqua NC Water Rate Division, likely due to water filtration and treatment projects; (4) the SSIC was consistently utilized in the range of $986k to $2.230 million annually; and (5) WSIC/SSIC projects and spending have outpaced non-routine, non-WSIC/SSIC plant additions costs in 2015, 2016, 2019, and 2020. Witnesses Henry and Junis also reviewed the types of plant additions that have occurred over the past several years.

Witnesses Henry and Junis conclude that whether considered individually or in the aggregate, the projects for which Aqua NC seeks deferral accounting treatment are not major non-routine, infrequent, non-regularly occurring, unforeseen investments of considerable complexity and significance for Aqua NC. Further, witnesses Henry and Junis maintain that in general, the Company continues to spend capital on projects such as pipes, pumps, and treatment systems. They state that since the last rate case, there has not been a substantial change in the Company's capital investment prompted by the passing of legislation or adoption of regulations that were transformative for the industry. They note that no new technology has been developed that is a cure all for aging infrastructure or water quality issues. They further note that the capital spending between plant accounts can vary from year to year based on age and deterioration. Witnesses Henry and Junis contend that overall sustained and strategic investment is necessary and has been shown to be consistent in recent years, and that the WSIC/SSIC mechanism addresses lag concerns for nearly half of this investment.

Witnesses Henry and Junis maintain that consideration of costs for deferral on an aggregated basis deemphasizes the nature of the capital expenditures and could even be characterized as an attempt to neutralize a key component of the Commission's longstanding criteria for deferral. Further, they note that there is no overarching "unusual and/or extraordinary" requirement or initiative naturally linking Aqua NC's capital expenditures.

Witnesses Henry and Junis recommend that the Commission deny Aqua NC's requests for deferral accounting based on the absence of "a clear and convincing showing that the costs in question were of an unusual and/or extraordinary nature" whether considered individually or in aggregate. Having reached the conclusion that Aqua NC failed to satisfy the requirement that it make a clear and convincing showing that its plant additions and the related costs are unusual or extraordinary so as to justify deferral accounting treatment, the Public Staff did not reach the issue of whether the costs sought to be deferred would have a material impact on the Company's financial condition or stability.

Witness Thill contends that Aqua NC's request for deferral accounting treatment in this proceeding is a reasonable request, that the Commission has the authority to utilize the tool in this fashion, and that it would be an effective and warranted means to afford Aqua NC a reasonable opportunity to earn its authorized return. Witness Thill maintains that with the use of deferral accounting, in the manner Aqua NC has requested, a utility like Aqua NC that invests robustly in this state can both make that necessary investment and avoid sacrificing its reasonable financial interests in the process.

Witness Thill states that for the same reasons that Aqua NC has requested authorization for deferral accounting for the post-test year additions, the Company continues to request prospective authorization to defer depreciation and carrying costs on post-rate case capital expenditures, other than routine replacements, until included in rates in Aqua NC's next rate case.

Pursuant to Section III, Paragraph BB of the Stipulation, the Stipulating Parties agree with the Public Staff's proposed adjustment related to deferred accounting on post-test year plant additions [Line 30]. The Stipulating Parties agree to the ratemaking adjustment shown on Line 30. Therefore, for purposes of this proceeding, the Company accepts the Public Staff's rejection of Aqua NC's novel request for aggregated deferral accounting treatment on post-test year plant additions as well as rejection of Aqua NC's request for "prospective authorization" to defer depreciation and carrying costs on post rate case capital expenditures, other than routine replacements, until included in rates in Aqua NC's next rate case. Based on the record in this procedding, the Commission finds it appropriate to approve the Stipulation regarding Aqua NC's deferral requests and to not allow Aqua NC to defer depreciation and carrying costs on an aggregated level of post-test year plant additions included in this proceeding or to grant prospective authorization to defer depreciation and carrying costs on post rate case capital expenditures until included in rates in the Company's next rate case.

Average Tax Accruals

Pursuant to Section III, Paragraph CC of the Stipulation, the Company accepts the Public Staff's proposed adjustment to average tax accruals [Line 31]. This adjustment will be updated for the final calculation of unemployment tax, regulatory fee, and property tax.

Service Revenues

Pursuant to Section III, Paragraph DD of the Stipulation, the Company accepts the Public Staff's proposed adjustment to service revenues [Line 32]. Further, as discussed in detail below, the Company withdraws its application for a conservation normalization factor.

Late Payment Fees

Pursuant to Section III, Paragraph EE of the Stipulation, the Company accepts the Public Staff's proposed adjustment to late payment fees [Line 33].

Uncollectibles and Abatements

Pursuant to Section III, Paragraph FF of the Stipulation, the Company accepts the Public Staff's proposed adjustment to uncollectibles and abatements [Line 34].

Capitalized Labor

Pursuant to Section III, Paragraph GG of the Stipulation, the Company accepts the Public Staff's proposed adjustment to remove capitalized labor [Line 35].

Transportation Regular Payroll

Pursuant to Section III, Paragraph HH of the Stipulation, the Company accepts the Public Staff's proposed adjustment to add transportation regular payroll [Line 36].

Open Positions and Update to Salaries and Wages

Pursuant to Section III, Paragraph II of the Stipulation, the Stipulating Parties agree to an adjustment in the amount of ($222,275) to remove four open positions and to update salaries and wages through March 31, 2020 [Line 37].

Leave Without Pay

Pursuant to Section III, Paragraph JJ of the Stipulation, the Stipulating Parties agree to an adjustment in the amount of ($5,043) to remove leave without pay [Line 38].

Standby and Overtime Salaries and Wages

Pursuant to Section III, Paragraph KK of the Stipulation, the Company accepts the Public Staff's proposed adjustment to reflect actual standby and overtime salaries and wages [Line 39]. Following the filing of its testimony on May 26, 2020, the Public Staff made corrections to its original position for this adjustment. The Company accepted the Public Staff's adjustment, as corrected.

Bonuses Related to Earnings per Share (EPS) and Executive and Board of Directors Compensation, Bonuses and Expenses; Corporate Service and Customer Operation Allocations; Open Positions

Bonuses Related to Earnings per Share (EPS), Executive and Board of Directors Compensation, Bonuses and Expenses

In Aqua NC's last general rate case (Sub 497), the Commission made the following Findings of Fact:

64. The Public Staff's proposed accounting adjustment to allocate 30% of North Carolina supervisory employee bonuses in the amount of $29,648 to shareholders and thereby exclude those expenses from the cost of service in this case is inappropriate.

65. It is not appropriate to adopt the Public Staff's recommended adjustment to allocate to shareholders 50% of the compensation, including pension and incentive plans, of the top five Aqua America executives totaling $213,756 in compensation and $80,845 in pensions and incentive plans.

66. It is appropriate to allocate to shareholders 25% of the compensation, including pension and incentive plans, of the top five Aqua America executives totaling $106,878 in compensation and $40,423 in pensions and incentive plans, thereby removing 25% of these expenses from Aqua NC's cost of service.

81. It is not appropriate to adopt the Public Staff's recommended adjustment to allocate to shareholders 50% of the compensation and expenses of the Aqua America Board of Directors totaling $58,419 in compensation and $8,691 in expenses.

82. It is appropriate to remove 25% of the Aqua America Board of Directors fees totaling $29,210 in compensation and $4,345 in expenses in this proceeding.

Bonuses

In this current rate case proceeding, Public Staff witness Feasel proposes in her direct testimony to remove 17.5% of the bonuses paid to North Carolina employees from expenses and allocate them to the Company's shareholders.

Witness Feasel testifies that the Company's application included bonuses paid to North Carolina employees, including Short-Term Incentive (STI) bonuses, stock options, restricted stock units amortization, and performance share units amortization. She observes that according to Aqua's most recent policies for the STI Plan, 50% of the metric weight depends on financial while 17.5% of the 50% is directly related to Essential Utilities' earnings per share. Witness Feasel contends that earnings per share directly benefit the shareholders' value instead of providing a benefit to the ratepayers. Thus, she removes 17.5% of the bonuses paid to North Carolina employees from expenses and allocates them to the Company's shareholders.

Witness Feasel notes that according to Aqua America, Inc.'s most recent policies for the 2009 Omnibus Equity Compensation Plan, the plan encourages the participants to contribute to the success of the Company, seeks to align the economic interests of the participants with those of the shareholders, and provides a means through which the Company can attract and retain officers, other key employees, nonemployee directors, and key consultants of significant talent and abilities for the benefit of its shareholders and customers. Thus, witness Feasel removes 50% of the stock options, restricted stock-units amortization, and performance share units amortization paid to North Carolina employees that were allocated from corporate service and Aqua Customer Operations (ACO), and allocated them to the Company's shareholders.

Witness Gearhart states in his rebuttal testimony that he does not agree with Public Staff witness Feasel's proposed adjustment to remove 17.5% of bonuses paid to North Carolina employees as well as 50% of stock options, restricted stock, and performance shared granted to North Carolina employees and to allocate those costs to shareholders. He maintains that the short-term incentive bonuses, stock options, restricted stock and performance shares are part of the total compensation package, paid to attract and retain qualified employees at Aqua North Carolina. He argues that the financial metrics that witness Feasel cites as arguments for this adjustment, reinforce to Aqua employees that it is their responsibility to serve the Company's customers in a prudent and efficient manner. Witness Gearhart asserts that the Company's ability to provide reliable service to its customers is directly related to its financial viability and linking a portion of those employees' compensation to a financial target encourages employees to achieve customer-based objectives in a cost-efficient manner.

Witness Gearhart explains the difference between the Public Staff's proposed adjustments for North Carolina employee bonuses in the Sub 497 rate case and this pending rate case proceeding. He notes that in the Company's 2018 Sub 497 rate case, the Public Staff proposed to allocate 30% of short-term incentive bonuses paid to Aqua supervisory employees. Witness Gearhart states that in this proceeding, the requested adjustment has been expanded to also include stock options, restricted stock, and performance share grants. He asserts that this adjustment has also been expanded to cover these items for all Aqua North Carolina employees; not just supervisors. Witness Gearhart states that Aqua North Carolina non-supervisory employees are eligible for bonuses referred to as "Chairman Awards" and during the test year, these awards were paid to over 100 Aqua North Carolina employees.

Witness Gearhart notes that in the Sub 497 Order, the Commission found that adjustments to supervisory employee bonuses was unreasonable and inappropriate, concluding that approving the Public Staff's position on this issue would send the wrong message to Aqua and its North Carolina supervisory personnel. He asserts that the Commission should deny the Public Staff's request in this proceeding for the same reasons set forth in the Sub 497 Order, especially now that the proposed adjustment would impact all levels of Aqua North Carolina employees.

Executive Compensation

Witness Feasel adjusts executive compensation in her direct testimony to remove 50% of the total compensation of the top five executives, which is comprised of total annual salary, Short-Term Incentive Plan (STIP), Long Term Incentive Plan (LTIP), and Benefits. She identifies the top five Aqua America executives who have charged compensation to Aqua, including: (1) Chief Executive Officer and President; (2) Executive Vice President and Chief Financial Officer; (3) Executive Vice President and Chief Operating Officer; (4) Executive Vice President and Chief Strategy and Corporate Development Officer; and (5) Executive Vice President, General Counsel and Secretary. Witness Feasel maintains that her adjustment reflects that the executives' duties and compensation encompass a substantial amount of activities that are closely linked to shareholder interests.

Witness Feasel states that her recommendation is not based on the premise that the compensation of these five executives is excessive or should be reduced. She explains that her recommendation is based on the Public Staff's opinion that it is appropriate and reasonable for the shareholders of the very 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 ratepayers.

Witness Feasel notes the various components included in the executives' compensation as discussed on pages 18-22 of her prefiled testimony and recommends that Aqua's executive compensation allocation from Aqua America be allocated 50% to the Aqua America shareholders. She comments that this adjustment is consistent with the positions taken by the Public Staff in past general rate cases involving the electric and natural gas utilities.

Witness Hanley states in his rebuttal testimony that he does not agree with witness Feasel's adjustment to reduce operating costs for executive compensation that includes the removal of 50% of the total compensation of the top five executives, which is comprised of total annual salary, Short-Term Incentive Plan, Long-Term Incentive Plan, and Benefits. He asserts that the Public Staff's position on this issue ignores and fails to follow the prior decision of the Commission, which resolved this issue in the Sub 497 rate case by imposing a 25% adjustment. Witness Hanley maintains that the Public Staff's proposed 50% adjustment is and continues to be excessive and unwarranted. Witness Hanley argues that while Aqua continues to fundamentally disagree with this type of adjustment, at a minimum, the Company contends that the Commission should follow with consistency the decision it employed in the Sub 497 case. Witness Hanley recommends that the Commission reject the Public Staff's adjustment in this regard.

Witness Hanley states that in the Sub 497 Order, the Commission specifically found that it was not appropriate to adopt the Public Staff's recommended adjustment to allocate to shareholders 50% of the compensation, including pension and incentive plans, of the top five Aqua America executives (Finding of Fact No. 65 at 19), and instead, the Commission adopted a 25% adjustment to those expenses (Finding of Fact No. 66). He notes that on page 101 of the Sub 497 Order, the Commission found the Public Staff's proposed adjustment to be unreasonable and not supported by the evidence presented.

Witness Hanley argues that Aqua sets compensation levels for its executives to attract and retain qualified personnel and to remain competitive in the market. He asserts that the efforts of Aqua's executives ultimately benefit customers through controlling costs and managing a strong overall company, which allows it to attract capital at lower costs. Witness Hanley maintains that this level of management strength and stability is extremely important in 2020 as the country addresses a pandemic, a potential financial crisis, and civil unrest. Witness Hanley further comments that one cannot overstate the importance of maintaining an unerring focus on key aspects of a major utility's responsibilities, including critical service quality for water and wastewater operations, reliability, environmental compliance, and a high level of safety for Aqua's customers and employees. Witness Hanley asserts that Aqua leaders have a responsibility not only to all investors in the Company, which include both shareholders and bondholders, but also to employees and most of all to its customers.

Witness Hanley states that Aqua is in a highly regulated business both on the environmental and financial side. He asserts that Aqua leaders are also charged with the responsibility of meeting these standards of providing safe and reliable water and wastewater service to customers served by Aqua in North Carolina. Witness Hanley comments that only then is Aqua granted an opportunity to earn a return on the dollars invested by shareholders. He asserts that the ability of Aqua as a public utility to meet the needs of its customers is the highest priority of all Company employees, as only then will the financial returns be achieved to attract both debt and equity capital needed in the business. Witness Hanley argues that a full compensation package, even for executive compensation, is a necessary part of the Company's overall cost of service to meet the needs of its customers, and a ratemaking adjustment of 50% to Aqua America executive compensation is not warranted.

Board of Directors' Compensation and Expenses

Witness Feasel proposes in her direct testimony an adjustment to remove 50% of the expenses associated with the Aqua America Board of Directors (BOD) that have been allocated to the Aqua jurisdiction. She comments that Aqua NC does not have a separate BOD. Witness Feasel states that the expenses allocated to the Aqua jurisdiction encompass the BODs' compensation, Directors' and Officers' liability insurance, and other miscellaneous BOD expenses. Witness Feasel testifies that shareholders vote on the election of directors and that the customers do not have a vote. She maintains that based on her review of the responsibilities of the Aqua America BOD, it is clear the BOD is responsible for acting in the best interests of the shareholders.

Witness Feasel testifies that it is appropriate and reasonable for the shareholders of the larger water and wastewater utilities to bear a reasonable share of the costs of compensating those individuals who have a fiduciary duty to protect the interests of shareholders, which may differ from the interests of ratepayers. She asserts that the premise of this adjustment is closely linked to the premise of the adjustment made by the Public Staff related to executive compensation. Witness Feasel further testifies that Directors' and Officers' liability insurance, while a necessary expense for a corporation, is obtained to defend the BOD in lawsuits brought by shareholders for issues such as merger claims and shareholders' derivatives. Witness Feasel recommends that it is appropriate for both ratepayers and shareholders to equally share the cost of BOD expenses.

Witness Hanley states in his rebuttal testimony that he does not agree with witness Feasel's adjustment to remove 50% of Aqua America's BODs' compensation. He asserts that the Public Staff has decided to relitigate the prior decision of the Commission as explained and adopted in the Sub 497 case. Witness Hanley argues that although parties and the Commission are generally free to change positions from case to case, the rationale imposed in the last rate case served as a guide to the industry and the Public Staff, as well as other intervenors. He asserts that Aqua continues to fundamentally disagree with any ratemaking adjustment here. Witness Hanley notes that in the Sub 497 Order, the Commission reached the following conclusions, in pertinent part, in support of its decision on BOD compensation and expenses:

> The Commission generally agrees with Aqua's assertions that adequate compensation is required to attract extremely competent, qualified members of a Board of Directors to lead a company such as Aqua America, Inc. and that North Carolina ratepayers and Aqua America, Inc. shareholders share a mutual interest in

> a highly skilled and qualified Board. The Commission also generally agrees that ratepayers' best interests depend on a regulated utility's ability to attract capital; in this instance, to support the level of investment required by Aqua as a regulated water and wastewater service provider in this state. As stated by Aqua, these financial and investment decisions are made at the parent company level and are integrally related to and supportive of the local company's ability to provide safe and reliable service. (Sub 497 Order at p. 104)

Witness Hanley maintains that while Aqua disagrees with any adjustment, if the Commission so chooses, the Company asserts that an adjustment of 25% for ratemaking purposes is the maximum adjustment which the Commission should adopt in this case for BOD compensation.

Witness Hanley further states that he does not agree with witness Feasel's adjustment, as reflected in Feasel Exhibit 1 Schedule 7, Lines 4-6, to remove 50% of the miscellaneous expenses (insurance and other fees) associated with the Aqua America BOD. He notes that for the reasons enunciated previously in his rebuttal testimony regarding both executive and Board of Director compensation, the Company requests that the Commission also reject the Public Staff's position on this issue. He notes that as with the executive and BOD compensation issues, if the Commission finds that an adjustment is necessary, Aqua urges the Commission to adhere to the Sub 497 case precedent. He argues that the 50% ratemaking adjustment proposed by the Public Staff is unreasonable and unjustified by the facts presented.

In Section III, Paragraph LL of the Stipulation, the Public Staff agrees to withdraw its proposed adjustment to state bonuses related to EPS [Line 40]. The Stipulation states that this is consistent with the Commission's decision in the Sub 497 rate case.

Further, Section III, Paragraph MM of the Stipulation states, in part, that the Stipulating Parties agree to settle issues related to executive compensation and bonuses and Board of Directors compensation and expenses consistent with the Commission's decision in the Sub 497 rate case by removing 25% of such expenses requested in the Company's application [Lines 41, 59, 60].

Based on the record in this proceeding, the Commission finds it appropriate to approve the Stipulation on the adjustments related to state bonuses related to EPS, executive compensation and bonuses, and Board of Directors compensation and expenses.

With one exception involving Line 42, the Stipulating Parties agree that no further adjustments should be made in this case regarding allocations from Aqua NC Corporate Services (ACS) and Aqua NC Customer Operations (ACO) [Lines 42 and 45]. The Stipulating Parties agree to an adjustment in the amount of ($92,050) to Line 42 related to open positions and terminations. Based on the record in this proceeding, the Commission determines it is appropriate to approve the Stipulation on allocations for ACS and ACO as well as he agreed upon adjustment related to open positions and terminations.

Capitalized Pensions and Benefits

Pursuant to Section III, Paragraph NN of the Stipulation, the Company accepts the Public Staff's proposed adjustment to remove capitalized pensions and benefits [Line 43].

Open Positions and Benefits

Pursuant to Section III, Paragraph OO of the Stipulation, the Stipulating Parties agree to an adjustment of ($122,256) to remove four open positions and to update benefits through March 31, 2020 [Line 44].

Corporate Sundries

Pursuant to Section III, Paragraph PP of the Stipulation, the Company accepts the Public Staff's proposed adjustment to remove unqualified benefits from Corporate Sundries [Line 46].

Fuel for Production

Pursuant to Section III, Paragraph QQ of the Stipulation, the Company accepts the Public Staff's proposed adjustment to fuel for production [Line 47].

Sludge Removal

Pursuant to Section III, Paragraph RR of the Stipulation, the Company accepts the Public Staff's proposed adjustment to sludge removal [Line 48].

Purchased Power

Pursuant to Section III, Paragraph SS of the Stipulation, the Company accepts the Public Staff's proposed adjustment to purchased power [Line 49].

Materials and Supplies

Pursuant to Section III, Paragraph TT of the Stipulation, the Company accepts the Public Staff's proposed adjustment to materials and supplies [Line 50].

Testing

Pursuant to Section III, Paragraph UU of the Stipulation, the Company accepts the Public Staff's proposed adjustment to testing [Line 51].

Contractual Services

Pursuant to Section III, Paragraph VV of the Stipulation, the Stipulating Parties agree to an adjustment to contractual services – legal [Line 52];

Pursuant to Section III, Paragraph WW of the Stipulation, the Company accepts the Public Staff's adjustment to contractual services – other – pump maintenance [Line 53];

Pursuant to Section III, Paragraph XX of the Stipulation, the Company accepts the Public Staff's proposed adjustment to contractual services–other-corporate sundries [Line 54];

Pursuant to Section III, Paragraph YY of the Stipulation, the Company accepts the Public Staff's proposed adjustment to contractual services-other-accrued expenses [Line 55]. Following the filing of its testimony on May 26, 2020, the Public Staff made corrections to this adjustment. The Company accepted the Public Staff's adjustment, as corrected.

Insurance Expense

Aqua NC witness Gearhart testifies that Aqua NC requested recovery in this proceeding of the five-year average of actual claims for liability insurance paid for the years 2014-2018. He states that this methodology was used by the Public Staff and approved by the Commission to calculate insurance expense in Aqua NC's previous rate cases. Witness Gearhart states that Aqua NC requested, in conjunction with this treatment for claims, Commission approval to create a deferred regulatory asset or liability for insurance claims paid in excess of (asset) or less than (liability) the authorized annual claim expense as approved by the Commission in this rate case (base level annual claims insurance recovery). He explains that if there is any excess balance (liability) or shortfall (asset) existing at the end of the next test year, that balance will be divided by two and applied to the base level annual claims insurance recovery amount. He proposed that this method be the recovery approach for all Aqua NC rate cases going forward. Witness Gearhart states that as an alternative, Aqua NC requested recovery for a zero deductible insurance policy for general liability, workers' compensation, and auto insurance.

Public Staff witness Junis strongly opposes these two requests by witness Gearhart asserting that both serve as disincentives to Aqua NC's safety practices. He states that the general liability and auto liability only pay claims when Aqua NC is at fault. Witness Junis maintains that Aqua NC should not be guaranteed recovery from customers for claims payments. He further maintains that the guarantee also serve as a disincentive to Aqua NC to minimize claims. In addition, witness Junis asserts that Aqua NC's guaranteed recovery of all workers' compensation claims would serve as a disincentive to Aqua NC's employee safety education and practices, including the provision of safe workplaces and personal protective equipment such as hard hats, safety glasses, and steel-toed boots. He also contends that the guarantee would be a disincentive for Aqua NC to minimize workers' compensation claims.

Witness Gearhart states that the Public Staff's methodology to calculate the amount of recoverable insurance claims expense has been to utilize a five-year average of actual claims paid. He maintains that as it stands now, using this five-year average methodology, Aqua NC will recover claims expense that will be $322,000 less than the actual claims amounts charged to Aqua NC in 2020. He notes that Aqua NC has agreed in this case to accept that reduction, but he requests that the approved five-year average, representative of the annual amount of claims paid and allowed in rates, be trued-up to actual claims paid as a regulatory asset or liability to be recovered in future rate cases.

Witness Gearhart disagrees with Public Staff witness Junis' assertion that the establishment of a regulatory asset or liability to recover actual claims paid will be a disincentive to Aqua NC's employee safety education and practices and would be a disincentive to Aqua NC to minimize workers' compensation claims. He states that witness Junis' suggestions are speculative, unfounded, and should be given no weight in deciding the matter at hand. He maintains that Essential Utilities and Aqua NC place an exceptional amount of attention on the safety culture of the utility. He further states that every Essential Utilities' state subsidiary is responsible for safety initiatives and metrics and none of them, aside from Aqua NC, are challenged on their insurance.

Pursuant to Section III, Paragraph ZZ of the Stipulation, the Stipulating Parties agree that the Company's stipulated insurance expense [Line 56] will be subject to a 50% true-up based on actual claims paid as a regulatory asset or liability, without a return or carrying costs, to be recovered in future rate cases. At the expert witness hearing, witness Junis testified that "[t]he Public Staff has no intention of such a true-up mechanism continuing in future rate cases". Tr. vol. 5, 76.

Based on the record in this proceeding, the Commission finds it appropriate to approve the Stipulation on the adjustments related to insurance expense in this proceeding and approves the stipulating parties agreement to a 50% true-up based on actual claims paid as a regulatory asset or liability, without a return or carrying costs, to be recovered in future rate cases. Such approval of the establishment of a regulatory asset or liability in this proceeding does not establish a precedent for future ratemaking treatment for adjustments to Aqua NC's insurance expense.

Regulatory Commission Expense

Public Staff witness Henry states that in this proceeding, Aqua NC applied for rate case expenses totaling $1,044,560 to be amortized over two years, resulting in an annual expense of $522,280. He notes that included in the total rate case expenses is $419,435 of unamortized rate case cost from Aqua NC's prior rate case proceeding, Docket No. W-218, Sub 497 (Sub 497), and $625,125 of estimated rate case costs for this current proceeding. He states that the estimated expenses for this current proceeding include legal fees totaling $390,625, consultant fees totaling $50,000, service company capitalized time totaling $71,000, and other rate case expenses totaling $113,500, of which $100,000 is for postage and printing notices to customers. In his prefiled testimony, witness Henry included actual rate case expenses incurred to date based on costs provided by the Company in response to Public Staff data requests. Witness Henry adjusts the actual amount of rate case expense to include an additional amount for printing and mailing notices to customers based on invoices provided by the Company for costs incurred to send the first notice to customers. Witness Henry notes that his adjusted rate case expense for this proceeding is $410,246, which is less than the Company estimated rate case expense of $625,125. Witness Henry recommends that the rate case expense for this current proceeding be updated to actual amounts incurred through the hearing date after review of supporting documentation provided by the Company.

Pursuant to Section III, Paragraph AAA of the Stipulation, the Stipulating Parties agree that regulatory commission expense adjustment [Line 57] will be updated to represent actual rate case expenses, plus agreed upon estimated costs to complete the rate case proceeding. The

Stipulating Parties also agree with the use of a three-year amortization in this case without a return or carrying costs on the unamortized balance.

In his late-filed exhibits filed on August 17, 2020, witness Henry included the agreed-upon updated level of rate case expense for use in this proceeding. Public Staff Henry Exhibit I, Schedule 3-4 Revised 8/17/20 includes total rate case expenses of $985,454 related to the current proceeding and unamortized rate case expense from Docket No. W-218, Sub 497 of $419,435. Witness Henry states that the Public Staff has amortized over three years the rate case expenses of Aqua NC for this proceeding, and has reamortized the unamortized balance of Aqua NC's rate case expenses for prior Aqua NC rate cases over the same period, resulting in total annual rate case expense amortization for both dockets of $468,296.

Based on the record in this proceeding, the Commission finds it appropriate to approve the Stipulation on the adjustments to rate case expense and include the agreed-upon updated level of rate case expense in this proceeding.

Capitalized Miscellaneous Expense

Pursuant to Section III, Paragraph BBB of the Stipulation, the Company accepts the Public Staff's proposed adjustment to remove capitalized miscellaneous expense [Line 58].

Miscellaneous Expenses for Corporate Sundries

Pursuant to Section III, Paragraph CCC of the Stipulation, the Company accepts the Public Staff's proposed adjustment to remove unqualified miscellaneous expenses for corporate sundries [Line 61].

Annualization and Consumption

Pursuant to Section III, Paragraph DDD of the Stipulation, the Stipulating Parties agree to an adjustment of $14,150 to annualization and consumption [Line 62].

Contra-OH Allocations

Pursuant to Section III, Paragraph EEE of the Stipulation, the Company accepts the Public Staff's proposed adjustment to Contra-OH allocations [Line 63].

Payroll Taxes

Pursuant to Section III, Paragraph GGG of the Stipulation, the Company accepts the Public Staff's proposed adjustment to payroll taxes [Line 65].

Purchased Water Loss

Aqua NC witness Pearce states in his direct testimony that in Aqua NC's last general rate case an amount of 15% was included for recoverable water losses by the Commission as recommended by the Public Staff. He notes that in its current filing Aqua NC has not included an amount of adjustment for recoverable water losses due to the Company's disagreement with the calculation method used in its last general rate case. Witness Pearce contends that a more appropriate methodology is the use of the Current Annual Real Losses (CARL) method as calculated using the American Water Works Association (AWWA) Water Audit standard. Witness Pearce states that in preparation for this proceeding NC has identified and completed water loss calculations that exceed the 15% allowance approved in its last rate case. He notes that these audits are currently being validated by George Kunkel, a third-party expert. Witness Pearce concludes by stating that CARL is a better long-term approach.

In direct testimony, Public Staff witness Darden discusses in detail the Public Staff's position regarding the appropriate adjustments for purchased water expenses. Witness Darden asserts that the amount of total purchased water expense of $2,114,412 included in Aqua NC's application is excessive, and instead she recommends an amount of $2,052,045, or a difference of $62,367.

Witness Darden argues that use of CARL and water audits is not a dependable substitute for the water loss standard due to the reliance on potentially inaccurate estimates and the absence of a water loss limit or objective. Witness Darden asserts that the appropriate standard for water loss to use in this proceeding is 15% as supported by the AWWA action level and the Commission's findings in the Sub 497 Order.

In rebuttal testimony, witnesses Pearce and Kunkel argue against the Public Staff's recommendations for the appropriate water loss standard to be utilized in this proceeding. Witness Pearce notes that he has extensive experience with leak detection, leak repair, and water loss reduction projects while witness Kunkel offers expertise with the AWWA water loss standards and software application. Witness Kunkel provides details and relevant examples in support of Aqua NC's argument on this issue, including his findings regarding the Chapel Ridge (Town of Pittsboro purchased water) water audit. Witness Pearce reiterates Aqua NC's position that the 15% gross water loss standard recommended by witness Darden is not an appropriate standard and in fact incentivizes a utility to spend in excess of the cost of the water for detection and resolution of water loss issues in some instances. He notes that Aqua NC currently uses the AWWA Water Audit method with performance indicators to prioritize investments in water loss reduction.

Witness Pearce states that witness Darden recommends a reduction of $62,367 to Aqua NC's purchased water costs, including a disproportionate reduction of $37,500 from the Town of Pittsboro purchased water expense. He notes that 60% of witness Darden's recommended total purchased water loss reduction is for the Town of Pittsboro purchased water. He comments that Aqua NC purchases water from the Town of Pittsboro for the Chapel Ridge system only. Witness Pearce further states that the Company has spent more than $135,000 in its efforts to comply with the Public Staff's recommended standard.

Witness Pearce describes the water leak reduction work undertaken by Aqua NC before and since the test period including a professional leak detection assessment and deployment of a District Metering Area (DMA) system pilot test. He maintains that the leak detection assessment involved an acoustic leak detection test for the entire Chapel Ridge system. Witness Pearce states that five leaks were found and repaired, and 24 additional small leaks were found on the customer side of the meter and notices were sent to the customers. Witness Pearce notes that several of the customer side leaks were determined to be due to leaky irrigation backflow devices. He maintains that the total estimated leakage from the five distribution system leaks was 2.35 gallons per minute. He comments that the DMA test pilot divides the system into five sub areas with continuous monitoring and data capture for any atypical flow. Witness Pearce states that the continuous monitoring allows for early detection and repair. Witness Pearce further states that outside of further system pressure reductions (which are inherently risky) or installation of higher accuracy water meters (which are susceptible to tampering), the Company has exhausted all known options for leak reduction in the Chapel Ridge system.

Witness Pearce next discusses losses due to fire department hydrant flushing. He states that during the test period the fire department flushed more than 62,000 gallons with a value of $848. Witness Pearce contends that flushing should be removed from the purchased water reduction total or the Company should be authorized to assess fire departments for flushing and testing water use. Witness Pearce disagrees with the 15% water loss standard recommended by witness Darden because it ignores Aqua NC's active pursuit of water loss measures and lacks evidence of improper operation or management.

Witness Pearce recommends that Aqua NC be allowed to complete water loss audits and focus on the systems that are performing more poorly and suspend the disallowance of actual purchased water costs incurred. He also recommends no adjustment for the Town of Pittsboro purchased water due to the extensive investigation of the Chapel Ridge system and the demonstrated extremely low leakage rates.

Aqua NC witness Kunkel argues against the continued use of the Public Staff's volumetric percentage performance indicator for determining water loss. He instead recommends that the Commission adopt the AWWA Water Audit method. He discusses multiple advantages of the AWWA model and offers some specific examples. Witness Kunkel refutes witness Darden's claim that the 15% loss standard is based in part on AWWA's recommended action level; a claim that witness Kunkel states is factually inaccurate. He states that AWWA specifically recommends against the use of any kind of percentage indicators in water loss assessment. Witness Kunkel further states that the AWWA characterizes the volumetric percentage indicator method recommended by the Public Staff to be imprecise and unreliable for assessing non-revenue water (NRW) levels. He comments that AWWA offers a best practice through its water audit method and free audit software that allows utilities to reliably quantify water losses and identify achievable and cost-effective reduction goals.

Witness Kunkel elaborates on the factors that lead the AWWA to consider the volumetric percentage performance indicators to be unreliable. Witness Kunkel further describes that the AWWA Water Audit model and the AWWA Free Water Audit Software collectively offer a highly reliable way to quantify water losses and inform cost-effective loss control strategies. He comments that the AWWA Water Audit model uses multiple indicators that represent apparent and real losses and offers a robust means of assessing water efficiency because no water is unaccounted for. Witness Kunkel maintains that the AWWA Free Water Audit software calculates loss volumes, costs of losses, and the performance indicators. He states that the free software features a grading or rating system for the data integrity with a scale of one to ten with one indicating low validity and ten indicating high validity. Witness Kunkel notes that these gradings are used to calculate the Data Validity Score (DVS) with an upper range of 100 and reflects the validity of the water audit. He maintains that the AWWA Water Audit emphasizes that water utilities should focus on volume of losses, cost impacts of losses, and data validity.

Witness Kunkel discusses his detailed validation of the 2019 AWWA water audit for Aqua NC's Chapel Ridge system supplied by the Town of Pittsboro. He comments that two of the most useful performance indicators in the AWWA Water Audit model are the leakage losses values of gallons per connection per day and gallons per mile of pipeline per day. Witness Kunkel maintains that the expression of gallons/mile/day is especially important for systems with a low density of customer connections per mile of pipeline. Witness Kunkel states that in conducting his validation of the Chapel Ridge audit, he compared the Chapel Ridge loss data for gallons/connection/day and gallons/mile of pipeline/day with the results of 500 validated water audits from California and Georgia. Witness Kunkel asserts that the Chapel Ridge unit rates for apparent and real losses compare with the lowest quartile of the Georgia and California dataset and well below the median values. For additional validation of the Chapel Ridge values, witness Kunkel also evaluated the DMA pilot test and acoustic leak detection studies. Witness Kunkel finds that the apparent and real losses in the Chapel Ridge system are extremely low and efforts to reduce them further are expensive and will likely result in only minimal additional reduction. He contends that this is not a financially prudent requirement to place on Aqua NC for the Chapel Ridge system. Witness Kunkel states that the Chapel Ridge volumetric percentage based on the water audit is 22% as compared to the 15% loss level currently being applied.

The Stipulation filed in this docket states in Section III, Paragraph HHH that Aqua NC and the Public Staff agree to utilize a 15% adjustment for allowable purchased water loss in this case [Line 66]. Further, Paragraph HHH states that Aqua NC and the Public Staff agree to work toward development of a mutually-agreeable standard based upon the methodology for purchased water systems set forth in Aqua NC's Pearce/Kunkle rebuttal testimony for implementation in Aqua NC's next general rate case, and to report the progress of those efforts in the next rate case.

During the expert witness hearing, Chair Mitchell asked the Panel of Public Staff witnesses Henry and Junis questions regarding Paragraph HHH of the Stipulation pertaining to the purchased water loss adjustment. She asked the Panel to describe where the parties are, in terms of coming to some sort of consensus approach on this issue. Chair Mitchell expressed that it is not clear that under the Stipulation the parties are working towards an approach that can be implemented before the next rate case. Witness Junis stated that for the purposes of this rate case, Aqua NC and the Public Staff are utilizing the Public Staff's position as filed in witness Darden's testimony. He noted that on a going-forward basis, as it states in the Stipulation, the parties will work together and in good faith consider the methodology preferred by Aqua NC witnesses Pearce and Kunkel in terms of possibly a leakage per mile or leakage per connection measure, as opposed to the percentage water loss adjustment preferred by the Public Staff. Witness Junis further explained that working through the give-and-take of negotiation and working together collaboratively, the question will be "what do you set as that benchmark." He stated that it is not real clear exactly what that will look like or what that will be but that the Public Staff will certainly consider using the AWWA water audit methodology.

The Public Staff Panel verified in response to Chair Mitchell's questions that the parties will use the information gathered for this rate case. Witness Junis explained that the hope is that

Aqua NC and the Public Staff would develop a threshold or benchmark, whatever that may be, and that the threshold or benchmark would be agreed upon and possibly reported to the Commission prior to Aqua NC's next rate case, or at least for implementation in Aqua NC's next rate case. Tr. vol. 4, 345-347.

Based on the record, the Commission accepts the agreement of the Stipulating Parties to utilize a 15% adjustment for allowable purchased water loss in this case [Line 66]. Further, the Commission instructs the Stipulating Parties to work toward development of a mutually-agreeable standard based upon the methodology for purchased water systems set forth in Aqua NC's Pearce/Kunkle rebuttal testimony for implementation in the Company's next general rate case, and to report on the progress of those efforts to the Commission within nine months of the issuance of this Order. Based upon the record in this docket, the Commission does expect Aqua NC and the Public Staff to come to a consensus recommendation for how purchased water loss will be reflected in Aqua NC's next general rate case proceeding.

Contract Services – Other – Temporary Labor

Pursuant to Section III, Paragraph III, the Stipulating Parties agree to an adjustment in the amount of $61,225 to contract services – other – temporary labor [Line 67].

Johnston County Purchased Water and Sewer Rates

Aqua NC witness Gearhart explains that the test year actual volumes of water purchased were used for all purchased systems and the most recent vendor pricing was applied to that volume.

Witness Gearhart explains three different scenarios regarding purchased wastewater treatment expense. Witness Gearhart states that for the Company's City of Charlotte purchased systems the test year actual volume was used, and the most recent vendor pricing was applied to that volume. He states that charges from Carolina Water Service were adjusted for CWSNC's 2019 rate increase in Docket No. W-354, Sub 360. Witness Gearhart states that a new expense for sending wastewater to Johnston County was added in May 2019 and as a result an adjustment has been made to include a full year of the Johnston County charge into the test year.

Public Staff witness Darden testifies that Aqua NC requested an additional adjustment to purchased water expense in the amount of $43,431.57 to reflect the impact of a proposed July 2020 rate increase for Johnston County purchased water accounts. Witness Darden states that the Public Staff does not support this adjustment because the rate increase has not yet been approved by the Johnston County Board of Commissioners and is therefore not known and measurable. Tr. vol. 4, 237.

In his direct testimony, Public Staff witness Franklin discusses his review and the Public Staff's recommendations regarding Aqua NC's proposed purchased wastewater expenses and pro forma adjustments. Witness Franklin agrees with Aqua NC's pro forma adjustments to Aqua NC's purchased wastewater expense except for the additional adjustment in the amount of $12,868 proposed in its purchased wastewater expense update. Witness Franklin states that the adjustment is made to reflect an anticipated July 2020 rate increase from Johnston County for treatment and transmission charges for Neuse Colony. Witness Franklin argues for the disallowance of the pro forma adjustment for the Johnston County rate increase because the information is based on an email from the Johnston County Public Utilities Director received before the County Manager and the Board of Commissioners had yet approved such rate increase.

Section III, Paragraph JJJ of the Stipulation states that the Public Staff agrees to withdraw its proposed adjustment to the Johnston County purchased sewer rate [Line 68] which was proposed in the Company's Item 18 update filed April 21, 2020, and has since been confirmed by the Public Staff.

During the expert witness hearing, Commissioner Brown-Bland asked the Panel of Public Staff witnesses Henry and Junis questions on this issue for clarification. Commissioner Brown-Bland asked whether the purchased water rate increase imposed by Johnston County effective July 1, 2020 has been reflected in the agreed upon operating expense for purchased water in the Stipulation. Witness Junis responded that for purchased wastewater, it has been but for purchased water, it has not been. He noted that the reason is that, for purchased wastewater, it is not a pass-through rate and that it is included in expenses. Witness Junis noted that for purchased water, it is a pass-through. He stated that instead of changing the rate design and revenue analysis to account for both the pass-through of the rate and also the inclusion in expense, the Public Staff requested Aqua NC to file a pass-through application after the rate case, so that the purchased water rate increase from Johnston County will just be an incremental increase easily captured in a pass-through. Tr. vol. 5, 18-19.[1]

Based on the record in this docket, the Commission finds it appropriate to approve the Stipulation on the purchased sewer rate to reflect the confirmed rate charged by Johnston County as of July 1, 2020.

Rounding Difference

Pursuant to Section III, Paragraph KKK of the Stipulation, the Company accepts the Public Staff's proposed adjustment to rounding difference [Line 69].

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9–21

Long-term Debt Cost, Capital Structure and Rate of Return on Common Equity

The evidence supporting these findings of fact and conclusions is contained in the Company's Application and corresponding NCUC Form W-1, the testimony and exhibits of the public witnesses, the direct and rebuttal testimony and exhibits of Company witness D'Ascendis, the direct testimony of Public Staff witness Hinton, the Stipulation, the additional testimony at hearing of Aqua NC witness Becker and Public Staff witness Henry, and the entire record of this proceeding.

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[1] The Commission notes in reviewing its dockets that Aqua NC has filed a request to reserve a new docket for the purpose of requesting Commission approval of a pass-through of bulk rate purchases which the Commission assumes will be for the July 1, 2020 Johnston County purchased water rate increase (See Docket No. W-218, Sub 535).

WATER AND SEWER – RATE INCREASE

The Stipulating Parties agreed to a settlement of these issues, as reflected in the filing of a Stipulation on July 1, 2020, and in consideration of a number of factors, including the impacts of the coronavirus pandemic on customers and the changing economic conditions.

The Stipulating Parties accepted the following as part of the Stipulation (all references are to the lines of Exhibit 1 to the Stipulation:

- the appropriate long-term debt (LTD) cost is 4.21% [Line 3]. The capital structure is 50% long-term debt and 50% common equity, and
- the appropriate rate of return on common equity to use in setting rates in this proceeding is 9.40% [Line 4].

The Stipulating Parties agree that the stipulated capital structure and stipulated levels of overall rate of return and rates of return on common equity and long-term debt are consistent with the requirements of N.C.G.S. § 62-133.

Rate of Return on Common Equity

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

Summary of Record Evidence on Rate of Return on Common Equity

In its Application and in the direct testimony of Aqua NC witness Dylan D'Ascendis, the Company requested approval for its rates to be set using a rate of return on common equity of 10.10%, including adjustments made for Company size and floatation costs. In his rebuttal testimony, witness D'Ascendis increased his recommended rate of return on common equity to 11.00% based upon his updated analyses, also including adjustments for size and flotation cost. Public Staff witness Hinton recommended a rate of return of equity of 8.90% if a Consumption Adjustment Mechanism or CAM is approved by the Commission, or 9.00% if a CAM is not approved by the Commission. For the reasons set forth herein, the Commission finds that a rate of return on common equity of 9.40% is just and reasonable.

The results derived from witness D'Ascendis' analyses in his direct and rebuttal testimony and witness Hinton's analyses in his direct testimony are as follows:

Summary of D'Ascendis' and Hinton's Common Equity Cost Rate Analyses

	D'Ascendis Direct	D'Ascendis Rebuttal	Hinton Direct
Discounted Cash Flow Model	8.81%	9.07%	8.60%
Risk Premium Model	10.21%	10.56%	9.40%
Capital Asset Pricing Model	9.35%	10.67%	n/a
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Proxy Group	11.29%	11.28%	n/a
Indicated Common Equity Cost Rate Before Adjustments	9.80%	10.75%	9.00%
Size Adjustment	0.20%	0.20%	n/a
Flotation Cost Adjustment	0.07%	0.05%	n/a
Consumption Adjustment Mech.	n/a	n/a	(0.10%)
Round Up	0.03%	n/a	n/a
Indicated Common Equity Cost Rate after Adjustments	10.07%	11.00%	8.90%
Recommended Common Equity Cost Rate after Adjustments	10.10%	11.00%	8.90%

Direct Testimony of Dylan W. D'Ascendis (Aqua NC)

Company witness D'Ascendis recommended in his direct testimony a rate of return on common equity of 10.10%. This 10.10% was based upon his indicated cost of common equity of 9.80%, a recommended size adjustment of 0.20% (as compared with the members of his Utility Proxy Group), and a recommended flotation adjustment of 0.07%. He rounded up his cost of common equity with these adjustments to 10.10%. Tr. vol. 2, 31.

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 an initial proxy group of six publicly-traded water companies that, in his rebuttal testimony, he increased to seven 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 (No-Price Regulated Proxy Group) which he described as comparable in total risk to the Utility Proxy Group.

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 October 18, 2019, divided by the average of closing market prices for the 60 trading days ending October 18, 2019.[1] He made an adjustment to the dividend yield because dividends are paid periodically, usually quarterly.

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[1] *See* Schedule DWD-3, page 1, column 1.

For witness D'Ascendis' direct testimony DCF growth rate, he testified he used only analysts' five-year forecasts of earning per share (EPS) growth. He testified the mean result of his application of the single-stage DCF model is 8.73%, the median result is 8.88%, and the average of the two is 8.81% for his Utility Proxy Group. *Id.* at 44.

Aqua NC 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 an 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 September 2019. He testified he added the forecasted 30-year U.S. Treasury Bond yield, 2.64%, to each company's PRPM-derived equity risk premium to arrive at an indicated cost of common equity. He testified his direct testimony mean PRPM indicated common equity cost rate for the Utility Proxy Group is 11.30%, the median is 10.38%, and the average of the two is 10.84%. *Id.* at 47.

Witness D'Ascendis testified 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 4.01%, and the average equity risk premium in his direct testimony to be 5.38% resulting in risk premium derived common equity to be 9.39% for his RPM using his total market approach. *Id.* at 57.

To determine the results of his risk premium method, he testified that in his direct testimony he averaged the PRPM result of 10.84% and the RPM results of 9.39%, and the indicated cost of equity from his risk premium method was 10.12%. *Id.*

For his CAPM, witness D'Ascendis testified 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 0.64 and a median beta of 0.63. *Id.* at 61.

Witness D'Ascendis testified that the risk-free rate adopted for both applications of the CAPM is 2.64%. This risk-free rate of 2.64% 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 first calendar quarter of 2021, and long-term projections for the years 2021 to 2025 and 2026 to 2030. *Id.* at 62.

Witness D'Ascendis stated that he used three sources of data to determine the risk premium in his CAPM: historical (Ibbotson), Value Line, and Bloomberg, that when averaged, result in an average total market equity risk premium of 9.87%. He testified that the mean result of his CAPM/ECAPM analyses is 9.39%, the median is 9.31%, and the average of the mean and median is 9.35%. *Id.* at 64.

Witness D'Ascendis also selected 10 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 direct testimony DCF result was 11.63%, his RPM cost rate was 11.41%, and his CAPM/ECAPM cost rate was 10.44%. Tr. vol. 2, 68.

Witness D'Ascendis also made a 0.20% equity cost rate adjustment due to Aqua NC'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 Aqua NC (whose common stock is not publicly-traded).

Direct Testimony of Public Staff Witness Hinton

Public Staff witness Hinton recommended a rate of return of equity of 8.90% if a CAM is approved by the Commission, or 9.00% if a CAM is not approved by the Commission.

Witness Hinton testified that, according to the April 2020 Mergent Bond Record, Moody's index yields on long-term "A" rated public utility bonds as of April 2020 were 3.50% as compared to 4.37% at December 18, 2018, which is the date the Commission issued the Sub 497 Rate Case Order, setting cost of equity at 9.70%. Witness Hinton further testified that the difference increased to 113 basis points when compared the average 4.63% yield observed during January 2014 at the time of settlement in Docket No. W-218, Sub 363. He further testified that the substantial 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.

Witness Hinton stated that the much lower current 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 ten years or more has 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 believes 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 30-year Treasury Bond yields that were predicted to rise to 4.30% in 2015, 4.70% in 2016, 5.20% in 2017, and 5.50% for 2020 through 2024. He presented a graph of 30-Year US Treasury Bonds yields which showed in 2016 the range was approximately 2.50% to 3.10%, and in 2017 the range was approximately 2.25% to 3.10%. Tr. vol. 4, 140-41. Witness Hinton testified that he had similar concerns with overestimated forecasts in Witness D'Ascendis Rebuttal Testimony in the Docket No. W-218, Sub 497, where the Blue Chip Consensus Forecasts predicted the 30-year Treasury Bonds would rise to 3.70% by the fourth quarter of 2019, though, according to the Federal Reserve, the highest observed yield on 30-year Treasury Bonds for the fourth quarter of 2019 is 2.43%, a forecast error of 127 basis points. *Id.*

Witness Hinton testified he used the DCF model and the RPM to determine the cost of equity for the Company. 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 eight water companies. He 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 February 14, 2020 through May 8, 2020. 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 1.70% for his proxy group of seven 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 ten 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-4.

Witness Hinton concluded based upon his DCF analysis that a reasonable expected dividend yield is 1.70% with an expected growth rate of 6.40% to 7.40%. Thus, he testified that his DCF analysis produces a cost of common equity for his comparable proxy group of water utilities of 8.10% to 9.10%. Tr. vol. 4, 151.

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 2020. 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-5, page 1 of 2, indicates that the average risk premium is 5.05% with a maximum premium of 5.97% 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 8.40%, a maximum cost of equity of 9.32%, and a minimum cost of equity of 7.08%. He performed a statistical regression analysis as shown on Exhibit JRH-5, page 2 of 2 in order to quantify the relationship of allowed equity returns and bond costs. He testified that applying the allowed returns to the current utility bond cost of 3.35%, resulted in a cost of equity estimate using the risk premium method of 9.40%. Tr. vol. 4, 153-154.

Witness Hinton concluded that based on all of the results of his DCF model that indicate a cost of equity 8.60%, and the risk premium model that indicates a cost of equity of 9.40%, he determined that the investor required rate of return on common equity for Aqua NC is between 8.60% and 9.40%. He concluded that 9.00% without the CAM, or 8.90% with the CAM is his single best estimate of the Company's cost of common equity. *Id.* at 156.

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 8.90%, the pre-tax interest coverage ratio is approximately 3.7 times. He testified that this tax interest coverage should allow Aqua NC to qualify for a single "A" bond rating. *Id.* at 157.

Witness Hinton testified that his recommended rate of 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 the Company'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 believes that this mechanism is noteworthy and is supportive of his 8.90% rate of return on common 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 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 Aqua NC 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. Witness Hinton observed that Aqua NC is owned 100% by Essential Utilities. A potential investor cannot purchase Aqua NC stock. All Aqua NC paid in equity capital is infused by Essential Utilities.

Rebuttal Testimony of Company Witness D'Ascendis

In his rebuttal testimony, Company witness D'Ascendis amended his recommended cost of equity to increase to 11.00% for Aqua NC. Witness D'Ascendis disagreed with witness Hinton that an 8.90% common equity rate is appropriate for Aqua NC. Tr. vol. 8, 257. 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 Aqua NC's previous Sub 497 case proceeding. According to witness D'Ascendis, both the academic literature and the Commission support the use of multiple models in determining a rate of 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 10.90% and 10.60%, respectively. *Id.* at 270-72.

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.

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.

In addition, witness D'Ascendis disagreed with witness Hinton on risk due to size. Witness D'Ascendis emphasized that smaller companies are less able to cope with significant events which affect sales, revenues and earnings. As examples, Witness D'Ascendis indicated that smaller companies face more exposure to business cycles and economic conditions, both nationally and locally; that the loss of revenues from a few large customers would have a far greater effect on a small company than on a larger company with a more diverse customer base; and that smaller companies are generally less diverse in their operations and have less financial flexibility. According to Witness D'Ascendis, consistent with the financial principle of risk and return in his direct testimony, such increased risk due to small size must be taken into account in the allowed rate of return on common equity.

Witness D'Ascendis testified that witness Hinton's corrected cost of common equity analysis results in a common equity cost rate of 10.05% for witness Hinton's comparable group of water utilities before adjustment for Aqua NC's increased risk due to size relative to the proxy group. Tr. vol. 8, 285)

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

Rate of return on common 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, e.g., 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 Aqua NC witness D'Ascendis and Public Staff witness Hinton. No rate of return on common equity expert evidence was presented by any other party.

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

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

DEC Sub 1146 Order at 50; *see also State ex rel. Utils. Comm'n v. Gen. Tel. Co.*, 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972) (*General Telephone*). As the North Carolina Supreme Court held in *General Telephone*, these factors constitute "the test of a fair rate of return declared" in *Bluefield* and *Hope*. *Id.*

The rate of return on common equity is, in fact, a cost. The return that equity investors require represents the cost to the utility of equity capital.

> [T]he cost of capital to the utility is synonymous with the investor's return, and the cost of capital is the earnings which must be generated by the investment of that capital in order to pay its price, that is, in order to meet the investor's required rate of return.

Morin, Roger A., *Utilities' Cost of Capital* 19-21 (Public Utilities Reports, Inc. 1984). "The term 'cost of capital' may [also] 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), at 388.

Long-standing decisions of the North Carolina Supreme Court have recognized that the Commission's subjective judgment is a necessary part of determining the authorized rate of return on common equity. *State ex rel. Utils Comm'n v. Public Staff-N. Carolina Utils. Comm'n,* 323 N.C, 481, 490, 374 S.E.2d 361, 369 (1988) (*Public Staff*). Likewise, the Commission has observed as much in exercising its duty to determine the rate of return on common equity, noting that such determination is not made by application of any one simple mathematical formula:

> Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the commissions are supposed to consider in making their Decisions, but no weights have been assigned.
>
> The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.
>
> In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:

> There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.

> As long as the allowed return falls within this zone, therefore, it is just and reasonable .... It is the task of the commissions to translate these generalizations into quantitative terms.

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

Order Granting General Rate Increase, *Application of Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina,* No. E-2, Sub 1023, at 35-36 (N.C.U.C. May 30, 2013), *aff'd, State ex rel. Utils. Comm'n v. Cooper,* 367 N.C. 444, 761 S.E.2d 640 (2014) (2013 DEP Rate Case Order) (additions and omissions after the first quoted paragraph in original).

Moreover, in setting rates the Commission must not only adhere to the dictates of both the United States and North Carolina Constitutions, but, as has been held by the North Carolina Supreme Court, it must set rates as low as possible consistent with constitutional law. *Public Staff,* 323 N.C. 481, 490, 374 S.E.2d 361, 370 (1988). Further, the North Carolina General Assembly has provided that the Commission must also set rates employing a multi-element formula set forth in N.C.G.S. § 62-133. The formula requires consideration of elements beyond just the rate of return on common equity element, and it inherently necessitates that the Commission make many subjective determinations, in addition to the subjectivity required to determine the rate of return on common equity. The subjective decisions the Commission must make as to each of the elements of the formula can and often do have multiple and varied impacts on all of the other elements of the formula. In other words, the formula elements are intertwined and often interdependent in their impact to the setting of just and reasonable rates.

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

> Fix such rate of return on the cost of the property . . .as will enable the public utility by sound management [1] to produce a fair return for its shareholders, *considering changing economic conditions and other factors* . . . [2] to maintain its facilities and

> services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and [3] to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and to its existing investors. [Emphasis added.]

The North Carolina Supreme Court has interpreted the above-emphasized language as requiring the Commission to make findings regarding the impact of changing economic conditions on customers when determining the proper rate of return on common equity for a public utility. *Cooper I*, 366 N.C. at 495, 739 S.E.2d at 548. The Commission must exercise its subjective judgment so as to balance two competing rate of return on common equity-related factors—the economic conditions facing the Company's customers and the Company's need to attract equity financing on reasonable terms in order to continue providing safe and reliable service. 2013 DEP Rate Case Order at 35-36. The Commission's determination in setting rates pursuant to N.C.G.S § 62-133, which includes the fixing of the rate of return on common equity, always takes into account affordability of public utility service to the using and consuming public. The impact of changing economic conditions on customers is embedded in the testimony of expert witnesses regarding their analyses of the rate of return on common equity using various economic models widely used and accepted in utility regulatory rate-setting proceedings. 2013 DEP Rate Case Order, at 38. Further,

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

Id. at 37. Economic conditions existing during the modified test year, at the time of the public hearings, and at the date of the issuance of the Commission's order setting rates will affect not only the ability of the utility's customers to pay rates, but also the ability of the utility to earn the authorized rate of return during the period the new rates will be in effect. However, in setting the rate of return, just as the Commission is constrained to address the impact of difficult economic times on customers' ability to pay for service by establishing a lower rate of return on common equity in isolation from the many subjective determinations that must be made in a general rate case, it likewise is constrained to address the effect of regulatory lag[1] on the Company by establishing a higher rate of return on common equity in isolation. Instead, the Commission sets the rate of return considering both of these negative impacts taken together in its ultimate decision fixing a utility's rates.

Thus, in summary and in accordance with the applicable law, the Commission's duty under N.C.G.S. § 62-133 is to set rates as low as reasonably possible to the benefit of the customers without impairing the Company's ability to attract the capital needed to provide reliable electric

[1] Regulatory lag exists where a utility's realized, earned return is less than its authorized return negatively affecting the shareholder's return on investment as other expenses and debts owed are paid ahead of investor return.

service and recover its cost of providing service. The Commission is guided by this premise when it makes it determination of the appropriate rate of return on common equity.

It is against this backdrop of overarching principles that the Commission analyzes the evidence presented in this case.

Discussion and Application of Law to the Facts in this Case Regarding the Issue of Rate of Return on Common Equity

The Commission has carefully evaluated the 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 rate of return on common equity that each witness recommends is shown below:

Summary of D'Ascendis' and Hinton's Common Equity Cost Rate Analyses

	D'Ascendis Direct	D'Ascendis Rebuttal	Hinton Direct
Discounted Cash Flow Model	8.81%	9.07%	8.60%
Risk Premium Model	10.21%	10.56%	9.40%
Capital Asset Pricing Model	9.35%	10.67%	n/a
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Proxy Group	11.29%	11.28%	n/a
Indicated Common Equity Cost Rate Before Adjustments	9.80%	10.75%	9.00%
Size Adjustment	0.20%	0.20%	n/a
Flotation Cost Adjustment	0.07%	0.05%	n/a
Consumption Adjustment Mech.	n/a	n/a	(0.10%)
Round Up	0.03%	n/a	n/a
Indicated Common Equity Cost Rate after Adjustments	10.07%	11.00%	8.90%
Recommended Common Equity Cost Rate after Adjustments	10.10%	11.00%	8.90%

The range of these results is 8.90% to 11.00%. Further, underlying the low result of 8.90% is a range of 8.10% to 9.10%, according to witness Hinton's testimony concerning his application of the DCF. Similarly, underlying the high result of 11.00% is a range of 8.60% (DCF) to 11.29% (Cost of Equity models applied to witness D'Ascendis' 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 rate of return on common 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 rate of return on common equity based on the testimony and evidence in this proceeding in accordance with the legal guidelines discussed above.

In so doing, the Commission finds and concludes that the direct testimony results of Company witness D'Ascendis (without adjustment) of 9.80% and the DCF and risk premium analysis testimony of Public Staff witness Hinton (without adjustment) of 9.00% are credible, probative, and are entitled to substantial weight. Coincidentally, the stipulated, Commission-approved rate of return on common equity of 9.40%, which is the average of the unadjusted direct analyses of Company witness D'Ascendis and Public Staff witness Hinton, represents a balance of company and customer interests.[1]

Having determined that the appropriate rate of return on common equity based upon the evidence in this proceeding is the stipulated return of 9.40%, the Commission notes that there was considerable discussion during the hearing concerning 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 common 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. Hinton Exhibit 5, which shows RRA Water Advisory data showing approved rate of return on common equity decisions for water utilities across the country since 2006 is helpful. According to this exhibit, the average rate of return on common equity for water utilities was 9.59% in 2014, 9.76% in 2015, 9.71% in 2016, 9.56% in 2017, 9.41% in 2018, 9.37% in 2019, and in the cases reported in 2020 the average is 9.27%. Thus, the stipulated, Commission-approved rate of return on common equity of 9.40% is also consistent with recent authorized returns for water utilities based upon the evidence in this proceeding.

These factors lead the commission to conclude that a 9.40% rate of return on common equity is supported by the substantial weight of the evidence in this proceeding. However, to meet its obligation in accord with the holding in *Cooper I*, the Commission will next address the impact of changing economic conditions on customers.

In this case, all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers, including in light of the significant human and economic impact posed by the COVID-19 pandemic. The testimony of witnesses D'Ascendis and Hinton, which the Commission finds entitled substantial weight, addresses changing economic conditions.

As to the impact of changing economic conditions on Aqua NC's customers, Public Staff witness Hinton testified he reviewed information on the economic conditions in the areas served

[1] The Commission notes that the Stipulation does not provide any indication as to how Aqua NC and the Public Staff actually derived their agreed-to 9.40% rate of return on common equity. Thus, the Commission, by noting the referenced "coincidence," does not infer that the Stipulating Parties' based their settlement on an average and asserts no such opinion in this case. The Commission's observation merely supports its independent determination that the stipulated 9.40% rate of return on common equity is reasonable and appropriate for adoption in this case.

by Aqua NC, specifically, the 2014, 2015, 2016, 2017, and 2018 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 Aqua NC's systems are located. The BEA data indicates that from 2017 to 2018, total personal income weighted by the number of water customers by county grew at a compound annual growth rate (CAGR) of 5.00%, which is slightly lower than the rate of 5.50% for the whole State, and that from 2014 to 2018, total personal income by county grew by 18.00%, which is slightly lower than the rate of 20.30% for the whole State.

Witness Hinton testified 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. The average Tier ranking that has been weighted by the number of water customers by county is 1.80. For the years 2016 through 2020, the average Tier ranking was 2.10 for the counties in the areas served by Aqua NC and, in each year, the average was higher than the state average. Witness Hinton testified that these economic measures indicate that Aqua NC's service areas has experienced stable economic conditions until the recent COVID pandemic.

Witness Hinton testified that, while it is too early to tell its full impacts, the COVID-19 pandemic has led to an increase in unemployment throughout the State. The North Carolina Department of Commerce issued a press release on April 29, 2020, which stated that the unemployment rate increased in 97 of the state's 100 counties during March 2020. Witness Hinton testified that while the March 2020 unemployment rate for the counties in Aqua NC's service territory was slightly higher than the state's unemployment rate, that the unemployment data for April 2020 was expected to worsen with rates of 10.00% or more, though he expected that unemployment rates would abate and the economy would improve as the State enters phases two and three of the Governor's plans.

Aqua NC witness D'Ascendis also testified on economic conditions in North Carolina. He testified he reviewed: unemployment rates from the United States, North Carolina, and the counties comprising Aqua NC's service territory; the growth in Gross National 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.

In his direct testimony on December 31, 2019, filed before the COVID-19 pandemic spread throughout North Carolina and the United States, witness D'Ascendis testified as to the falling rate of unemployment, real Gross Domestic Product growth, and median household income growth, and the strong correlation of these measures between North Carolina and the United States. Witness D'Ascendis also testified 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.

In his rebuttal testimony filed June 2, 2020, witness D'Ascendis generally agrees with witness Hinton's conclusions that the full effect of the Coronavirus on Aqua NC's customers is yet to be determined, and that once the crisis passes, whenever that may be, the economic slowdown will diminish.

The economic impact testimony of witnesses Hinton and D'Ascendis is credible, probative, and is entitled to substantial weight.

The Commission's review also includes consideration of the evidence presented during the public hearing by public witnesses, all of whom presently are customers of Aqua NC. The hearing yielded 24 witnesses who chose to be heard regarding their respective positions on Aqua NC's Application to increase rates. The testimony presented at the hearing by Aqua NC customers illustrates the difficult economic conditions facing a number of North Carolina citizens during the COVID-19 pandemic. The Commission accepts as credible, probative, and entitled to substantial weight, the testimony of the public witnesses.

Based upon the general state of the economy and the continuing affordability of water and wastewater utility service, and after weighing and balancing factors affected by the changing economic conditions in making the subjective decisions required, the Commission concludes that an allowed rate of return on common equity of 9.40% will not cause undue hardship to customers even though some will struggle to pay the increased rates resulting from this decision. When the Commission's decisions are viewed as a whole, including the decision to establish the rate of return on common equity at 9.40%, the Commission's overall decision fixing rates in this general rate case results in lower rates to consumers in the existing economic environment.[1]

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 common equity of 9.40% instead of 10.10%, 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, and thus, accrue to the benefit of consumers' ability to pay their bills in this economic environment.

Based on the changing economic conditions and their effects on Aqua NC's customers, the Commission recognizes the financial difficulty that the increase in the Company's rates will create for some of Aqua NC's customers, especially low-income customers. As shown by the evidence,

[1] The Commission notes consumers pay rates, a charge in dollars per 1,000 gallons for the water they consume and a monthly flat rate for residential wastewater customers. They do not pay a "rate of return on equity," though it is a component of the Company's cost of providing service which is built into the billed rates. Investors are compensated by earning a return on the capital they invest in the business. Per the Commission determination of the rate of return on common equity in this matter, investors will have the opportunity to be paid in dollars for the dollars they invested at the rate of 9.40%.

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

The Commission finds and concludes that these investments by the Company provide significant benefits to Aqua NC's customers. The Commission concludes that the rate of return on common equity—stipulated by the Public Staff and Aqua NC and approved by the Commission in this proceeding---appropriately balances the benefits received by Aqua NC's customers from the Company's provision of safe, adequate, and reliable water and wastewater service with the difficulties that some of Aqua NC's customers will experience in paying increased rates.

The Commission notes further that its approval of a rate of return on common equity at the stipulated level of 9.40% or for that matter at any level, is not a guarantee to the Company that it will earn a rate of return on common equity at that level. Rather, as North Carolina law requires, setting the rate of return on common equity at this level merely affords Aqua NC the opportunity to achieve such a return. The Commission finds and concludes, based upon all the evidence presented, that the stipulated rate of return on common 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

Aqua NC witness D'Ascendis recommended the use of a ratemaking capital structure consisting of 50.00% long-term debt and 50.00% common equity. He testified this capital structure is based on a test year capital structure for Aqua NC, ending September 30, 2019.

Public Staff witness Hinton also testified recommending a 50.00% long-term debt and 50.00% common equity capital structure. The Stipulation also supports a 50.00% long-term debt, 50.00% common equity capital structure. No other party presented evidence as to a different capital structure.

Accordingly, the Commission finds and concludes that the stipulated capital structure of 50.00% common equity and 50.00% long-term debt is just and reasonable to all parties in light of all the evidence presented.

Cost of Debt

In its Application, the Company proposed a long-term debt cost of 4.25%. Public Staff witness Hinton testified that the appropriate embedded cost of Aqua NC's long-term debt is 4.21%. The Stipulation provides for a 4.21% cost of debt. The Commission finds for the reasons set forth herein that the stipulated 4.21% cost of debt is just and reasonable. The 4.21% debt cost of the Stipulation gives customers the benefit of reductions in Aqua NC's lower cost of debt after the end of the test year.

No intervenor offered any evidence supporting a debt cost below 4.21%. The Commission, therefore, finds and concludes that the use of the stipulated debt cost of 4.21% is just and reasonable to all parties based upon all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

Acceptance of Stipulation

No party filed a formal statement or testimony indicating opposition to the Stipulation; however, the AGO did pursue cross-examination of Aqua NC (by way of introduction of cross-examination exhibits) concerning certain communications from the DEQ. The Stipulation is binding as between Aqua NC and the Public Staff, and conditionally resolved certain specific matters in this case as between those two parties. Through the end of the evidentiary process, the AGO neither approved nor expressly disapproved of the partial settlement regarding the specific settled issues reflected in the terms of the Stipulation. There are no other parties to this proceeding.

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 North Carolina law. A stipulation entered into by less than all parties in a contested case proceeding under Chapter 62 "should be accorded full consideration and 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.*

The Commission concludes, based upon all the evidence presented, that the Stipulation was entered into by the Stipulating Parties after full discovery and extensive negotiations and represents a reasonable and appropriate proposed negotiated resolution of certain specific matters in dispute in this proceeding and that the AGO did not expressly object to the settlement. Based upon all of the evidence in the record, the Stipulation will provide Aqua NC and its ratepayers just and reasonable rates when combined with the rate effects of the Commission's decisions regarding the Unresolved Issues in this proceeding.

The Commission gives substantial weight to the testimony of Aqua NC witness Becker regarding the Stipulating Parties' protracted efforts in negotiating the Stipulation, and regarding the benefits of it. Further, the Commission gives significant weight to the settlement testimony of

Public Staff witnesses Henry, which in his discussion of the benefits that the Stipulation will provide to customers and his testimony describing the compromise reflected in the Stipulation's terms, indicates the Public Staff's commitment to fully represent the using and consuming public.

As a result, the Commission finds and concludes that the Stipulation is the product of the give-and-take between the Stipulating Parties during their settlement negotiations in an effort to appropriately balance Aqua NC's need for increased revenues and its customers' needs to receive safe, adequate, and reliable water and wastewater service at the lowest possible rates. In addition, the Commission finds and concludes that the Stipulation was entered into by the Stipulating Parties after substantial discovery and negotiations, and, with the exception of the Unresolved Issues, that it represents a proposed negotiated resolution of the matters in dispute in this docket.

The provisions of the Stipulation are entitled to substantial weight and consideration in the Commission's decision because they are based on evidence presented in the case, they are just and reasonable to all parties to this proceeding, and they serve the public interest. Therefore, the Stipulation should be approved in its entirety.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

Conservation Normalization Factor and Consumption Adjustment Mechanism

The evidence for these findings of fact is contained in the verified Application, the testimony of Aqua NC witnesses Becker and Thill, and the testimony of Public Staff witness Junis and the Stipulation.

In its Rate Case Application, Aqua NC proposed use of an adjustment for its historical consumption in development of the Company's pro forma usage billing determinants. More specifically, Aqua NC applied a conservation normalization factor to the three-year average historical consumption figures for each of the Company's three water rate divisions. Aqua NC asserts that a simple three-year historical average ignores the impact of continued declining consumption being experienced across the state and across the country, driven by consumer conservation.

Also in its Rate Case Application, Aqua NC proposed implementation of a CAM for approval by the Commission pursuant to N.C.G.S. § 62-133.12A.

Aqua NC Witness Becker

Aqua NC President Shannon Becker's direct testimony addresses the impact that the determination of consumption has on the Company's ability to meet its authorized rate of return on common equity. Witness Becker testifies that, as described in witness Thill's testimony, a portion of the requested revenue increase in this case is a result of reduced consumption per customer. He states that, although the trend is clearly one of declining consumption, consumption can also increase significantly during extended periods of warm weather. Therefore, witness Becker asserts that fluctuation in consumption is a factor that must be addressed in order for Aqua NC to meet the approved revenue requirement necessary to attain its authorized rate of return on common equity. He maintains that Aqua NC depends on the integrity and accuracy of a rate design in order to have an opportunity to achieve its authorized return. He further maintains that key to this opportunity is reasonable accuracy in the derivation of consumption figures. Witness Becker contends that consumer consumption levels that are above rate case projections could provide excess revenues, while consumption levels that are below rate case projections could result in a deficit. Witness Becker asserts that the persistent decline in consumption has regularly eroded the Company's opportunity to earn its authorized rate of return. He states that the utilization of a historic three-year consumption average to determine rates has proven to be insufficient to support the revenue requirement necessary for Aqua NC to have a reasonable opportunity to attain the Company's authorized rate of return on common equity.

Witness Becker maintains that recognition of a historical conservation experience and its application in the Company's rate design will better align the ratemaking consumption data with actual current customer usage and, thus, will more fairly support the Company's ability to realize its authorized rate of return on common equity. Witness Becker notes that Aqua NC witness Thill describes the Company's proposal to apply a conservation normalization factor to accomplish this objective in his direct testimony.

Witness Becker testifies that Aqua NC was also proposing a CAM in this general rate case proceeding for approval by the Commission. In an attempt to address the challenges of utilizing a persistently declining historic consumption pattern and address potential swings in average customer consumption, witness Becker testifies that Aqua NC supported legislation that authorized the Commission to "adopt, implement, modify, or eliminate a rate adjustment mechanism for one or more of the Company's rate schedules to track and true-up variations in average per customer usage from levels approved in the general rate case proceeding" under House Bill 529 (Session Law 2019-88) which was signed into law on July 8, 2019, adding N.C.G.S. § 62-133.12A to 19 Article 7 of Chapter 62 of the General Statutes. Witness Becker states that this mechanism, if approved for use, is intended to provide a true-up of the average per customer consumption levels used to calculate rates necessary to achieve an approved revenue requirement. He asserts that it provides the Company and its customers rate protections during periods of fluctuating consumption, high or low, that could otherwise result in over or under collections of approved revenue levels. Since the Commission's CAM rulemaking in Docket No. W-100, Sub 61, has just gotten underway, witness Becker states that Aqua NC reserves the right to withdraw the Company's request to implement a CAM in this rate case docket, subject to the final terms and conditions that may be ordered.

Aqua NC Witness Thill

In his direct testimony Aqua NC witness Thill describes and discusses the supporting rate design exhibits prepared and submitted as part of the Company's Rate Case Application pertaining to billing determinants, revenues, and proposed rates. He also discusses, in detail, the Company's contention that over the last several years, the average consumption per customer has varied widely due to environmental factors, conservation, and pricing. Witness Thill testifies that the fact is that Aqua NC's customer habits are changing and, overall, consumption is declining due to a number of persistent factors, including more efficient plumbing fixtures and household appliances, governmental programs encouraging greater efficiency in water use, changes in landscaping patterns, and consumer response to conservation price signals.

Witness Thill testifies that Aqua NC included an adjustment for consumption in development of the Company's pro forma usage billing determinants. More specifically, witness Thill states that a conservation normalization factor had been applied to the three-year average consumption figures for each of the Company's three water rate divisions. According to witness Thill, the Company's proposed conservation normalization factor attempts to correct the three-year consumption average by rolling the experience to levels better reflecting those at the end of the test year. He agrees that the three-year average advocated by the Public Staff in Aqua NC's water and wastewater ratemaking adjustments accomplishes a smoothing of historic year-to-year consumption patterns impacted by weather. Witness Thill asserts that this policy seeks to protect both the customer and the utility from rates that might be skewed by use of consumption levels driven by short-term weather events (droughts, floods, etc.). However, witness Thill testifies that a simple three-year historical average ignores the impact of continued declining consumption experiences across the state and across the country, driven by consumer conservation. Witness Thill provides an example in his testimony to illustrate his point.

In describing how the lack of a conservation normalization factor affects Company revenue, witness Thill testifies that the current approach overstates consumption (by understating the reality of the declining trend in consumption), thereby undermining the integrity of the ratemaking formula. He states that the formula operates by application of a certain price to the expected gallons to be sold by the utility; however, if the gallons actually sold are consistently fewer than the gallons utilized to set rates, the Company is hobbled in its efforts to recover its revenue requirement, and thus to earn its authorized rate of return. Witness Thill then provides an illustration to demonstrate his point; but also states that the Company recognizes that there are a number of assumptions used in this illustration and does not propose that the number is a specific measure of actual lost revenue. He explains that the Company has, instead, presented this calculation to show the design deficiency inherent in the traditional calculation and a general indication of the magnitude of the impact on utilities when using steadily declining historic averages to calculate consumption necessary to recover an established revenue requirement in a rate case. Witness Thill states that his illustration supports the Company's contention that the three-year average should be paired with a conservation normalization factor to better represent real consumption levels as of the end of the test year – not one that effectively utilizes an average consumption level that existed eighteen months ago (i.e., the mid-point of the three-year average). He contends that this updated concept is consistent with similar traditional efforts to utilize the full customer population at that same date.

Witness Thill then describes how the Company's proposed conservation normalization factor was computed and applied. Witness Thill further testifies that the Company's proposed conservation normalization factor is not projective in nature; that the factor uses only known and measurable historical data as of the end of the test year (to be updated at the end of the post-test year period); and that the factor does not project a furtherance of any consumption trend.

Witness Thill also testifies that implementation of a consumption adjustment mechanism or CAM would not accomplish the same purpose as a conservation normalization factor. Witness Thill states that, while both measures seek to address a deficiency in the revenue sufficiency produced by the historical calculation, the CAM does not address revenue stability. He maintains that the conservation normalization factor intends to more fully collect the revenue authorization in the period of consumption, which helps best match the revenues with associated expenses. He contends that the CAM provides a mechanism to correct any realized deficiency or surplus in the following year. Witness Thill further contends that in collecting a more appropriate level of revenues in the year of consumption, there is greater stability in customer bills due to the absence of prior year adjustments.

Public Staff Witness Junis

Regarding average consumption per customer, Public Staff witness Junis testifies that he adjusted the consumption for the updated data using a three-year average (April 2017 through March 2020) compared to the Company's application of its conservation normalization factor to the three-year average (October 2016 through September 2019). The consumption adjustment resulted in a 0.65% increase for Aqua NC Water, 5.22% decrease for Aqua NC Sewer, 0.66% increase for Brookwood Water, 8.13% decrease for Fairways Water, and 11.52% decrease for Fairways Sewer to reflect the difference between the test year ending September 30, 2019, per customer usage and the three-year average for the period ending March 31, 2020. Witness Junis states that Aqua NC's testimony is largely duplicative of its contentions expressed in the last rate case regarding a downward trend in consumption that prevents the Company from earning its authorized rate of return. Witness Junis testifies that, as noted in the Environmental Finance Center (EFC) Study, Aqua NC water customers' consumption has stabilized close to an average of 5,000 gallons per month. From Thill Direct Exhibit 1, witness Junis states that he had converted the measurement units and graphically illustrated the active customer bills, billed consumption, average monthly consumption per bill, and the three-year average monthly consumption per bill for the 12-month period ending September 30, 2019 as shown in Junis Exhibit 1.

Witness Junis testifies that, on a consolidated basis, there has been a clear leveling out or stabilization of average monthly consumption since the dip in 2013. He maintains that the average monthly consumption each year may fluctuate above or below the three-year average, however, the band of variation has narrowed significantly in recent years. He notes that on page two of Junis Exhibit 1, the graphs moving down the page illustrate this trend as the time period is limited to progressively recent data. He asserts that the three-year average is a relatively accurate representation of expected consumption in the short-term. He notes that this is especially true in light of Aqua NC's plans to file rate cases every 15 months. In addition, witness Junis states that as shown in Junis Figure 1, there has been a consistent, gradual growth in customers and total consumption since 2013. He maintains that as a result of this growth, both revenues from base facilities charges and volumetric charges have increased from year to year. Therefore, he asserts that Aqua NC's actual total revenues have increased from year to year and would exceed the revenue requirement approved by the Commission in the prior two rate cases.

Witness Junis testifies that, using the trend summary workpapers of Company witness Thill that are part of his billing analysis and rate design, he has graphically illustrated the average monthly consumption per bill for the updated test year ending March 31, 2020, and the three-year average monthly consumption per bill for the 12-month periods ending March 31 as shown in Junis Exhibit 2.

Witness Junis states that the observations are similar to those previously noted with the exceptions that Brookwood Water has a consistent downward trend in average monthly consumption and Fairways Water average consumption spiked in the most recent 12-month period ending March 31, 2020. According to witness Junis, it would be reasonable to expect the Brookwood Water average monthly consumption to eventually flatten and stabilize and for the Fairways Water to return to equilibrium. He notes that from reviewing the updated data on a consolidated basis, there has been a clear leveling or stabilizing of average monthly consumption. He states that on page five of Junis Exhibit 2, the third graph at the bottom of the page shows the most recent five years of average monthly consumption per bill and the three-year average consumption. The three-year average of 5,087 gallons per monthly bill would have been within +/-4% of the subsequent years (or TY Avg in the graph), including higher in two years and lower in two years.

Witness Junis testifies that the explanation for the unusually low consumption in the 12-month period ending March 31, 2019, was weather. More specifically, he notes that based on a review of climate data from the National Oceanic & Atmospheric Administration's station at the Raleigh-Durham International Airport, the representative area experienced above-average precipitation, both in quantity and frequency, in 2018 and early 2019. Witness Junis further states that this conclusion is further supported by data from the United States Drought Monitor (USDM). He states that North Carolina experienced a historic drought beginning in 2007. Areas of the State were designated as being under severe drought (D2) starting in April 2007 and did not completely return to below severe drought levels until April 2009. He notes that at the time, 71 counties in North Carolina were classified as experiencing exceptional drought conditions. He maintains that this is in stark contrast to more recent years. He notes that the graphs in Junis Exhibits 3 and 4 progressively narrow the focus on the updated three-year average consumption data period ending March 31, 2020. He states that the updated test year and the prior two years (i.e., TY, TY-1, and TY-2) experienced minimal moderate drought conditions, undesignated to minimal abnormally dry conditions, and moderate drought conditions, respectively. He further states that with the exception of the first two months, TY-1 or the 12-month period ending March 31, 2019, experienced minimal dry conditions. Therefore, he concludes that consumption was unusually low.

Witness Junis states that the Public Staff recommends that the Commission deny the utilization of the conservation normalization factor. He maintains that the average monthly consumption per bill has stabilized in the last five years, and it would be unreasonable to further reduce average consumption based on historical data that is not representative of current customer usage habits and conditions. He states that the conservation normalization factor in the Company's Application includes data from as far back as October 2008 and, even if updated, from April 2009. He observes that the average consumption during the years 2008 through 2012 was higher and trended downward. However, he notes that trend is no longer occurring and, therefore, using it to calculate the conservation normalization factor would underestimate average monthly consumption per customer. Witness Junis testifies that this is especially important when the number of customers and the total consumption continues to increase and as concluded by the EFC, that growth in revenues outpaces the associated variable expenses.

As part of the Stipulation, Aqua NC accepted the Public Staff's proposed adjustment to service revenues and the Company withdrew its application for the application of a conservation normalization factor in this proceeding.

In regard to the Company's proposal in its Application to implement a CAM, witness Junis testifies that Aqua NC has requested authority to implement a CAM within each of the Company's five Rate Divisions, pursuant to N.C.G.S. § 62-133.12A and subject to the final rules to be defined by the Commission under Docket No. W-100, Sub 61. Witness Junis observes that on page 18 of its Application, Aqua NC asserts that the mechanism, if approved for use, is intended to provide a true-up of the average per-customer consumption levels used to calculate rates necessary to achieve an approved revenue requirement. He testifies that Aqua NC further asserts that the mechanism provides the Company and its customers rate protections during periods of fluctuating consumption, high or low, that could otherwise result in over- or under-collection of approved revenue levels. He states that Aqua NC also reserves the right to withdraw the CAM if the rules to be adopted in Docket No. W-100, Sub 61, render the use of a CAM infeasible for the Company.

Witness Junis testifies that the direct testimony of Company witness Becker regarding the proposed CAM generally mirrors the application language above, with the exception that Aqua NC supported the legislation under House Bill 529, and he makes no mention of infeasibility but rather states, "Aqua reserves the right to withdraw the Company's request to implement a CAM in this rate case docket, subject to the final terms and conditions that may be ordered."[1] Witness Junis notes that this is essentially the totality of the Company's testimony and evidence in support of its CAM request in the rate case.

Witness Junis testifies that the Public Staff does not believe the CAM,[2] as proposed by Aqua NC jointly with CWSNC, is in the public interest and recommends that the Commission deny the request to implement the mechanism. Witness Junis further testifies that the Commission's Order in the rulemaking proceeding states, "the Commission is not persuaded that the Companies' proposal is a reasonable or appropriate means of implementing the CAM Statute." Witness Junis maintains that until the Company either withdraws or amends its request, it would be premature for the Public Staff to evaluate the request or proffer any recommendation. Witness Junis notes that the Commission, in recognition of Aqua NC's pending rate case and the Company's expressly reserved right to withdraw or modify the requested CAM, allowed Aqua NC 30 days (to June 11, 2020) from its Order dated May 12, 2020, to amend its application with respect to the CAM.

Aqua NC Witness Thill Rebuttal

In his rebuttal testimony, witness Thill withdrew the Company's request for implementation of a CAM in this proceeding, electing, instead, to pursue implementation of a CAM in its next general rate case, developed in light of the Commission's rules issued on May 12, 2020, in Docket No. W-100, Sub 61.

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1 Page 33, line 7, through page 34, line 6, Direct Testimony of Company witness Shannon Becker filed in Docket No. W-218, Sub 526, on December 31, 2019.

2 Initial Comments Regarding Rulemaking Proceeding filed on January 31, 2020, jointly by Aqua NC and CWSNC in response to the Commission's Order Establishing Rulemaking Proceeding and Granting Petitions to Intervene in Docket No. W-100, Sub 61.

With respect to Aqua NC's requests for a conservation normalization factor and a consumption adjustment mechanism, since these matters have been withdrawn by the Company and are no longer an issue in this proceeding, the Commission does not make any findings or conclusions with respect to these matters in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 24-29

Rate Design – Water and Wastewater, Excluding Conservation Pilot Program

The evidence for these findings of fact is contained in the verified Application, the testimony of Aqua NC witness Thill, the testimony of Public Staff witness Junis, and the AGO's brief.

Aqua NC Witness Edward Thill Direct Testimony

Aqua NC witness Edward Thill testifies on direct that the Company proposes to utilize the same rate design fixed/variable ratios that were proposed by the Public Staff and approved by the Commission in the Company's most recent prior rate case (Docket No. W-218, Sub 497). He states that that rate design structure included allocations of base facility charges (BFCs) and volumetric charges for the average water customers as follows: 40%/60% for the Aqua NC Water Rate Division; 41%/59% for the Brookwood Water Rate Division; and 44%/56% for the Fairways Water Rate Division.

Witness Thill testifies that the Company proposes the continuation of the flat rate wastewater rates for residential customers. Aqua NC bills commercial wastewater customers a volumetric rate. Aqua NC also bills residential wastewater customers a volumetric rate on systems for which the Company purchases bulk wastewater treatment from Charlotte Water. In its Application, the Company proposed to increase the monthly residential wastewater flat rate from $72.04 to $80.18.

In support of his recommendations regarding the Company's proposed water and wastewater rate design proposals, witness Thill references a March 31, 2016 report produced by the EFC at the UNC School of Government titled "Studies of Volumetric Wastewater Rate Structures and a Consumption Adjustment Mechanism for Water Rates of Aqua North Carolina, Inc." (EFC Report). Tr. vol. 4, 15-16. Aqua NC witness Thill states that the EFC Report notes that short-term fixed expenses accounted for 83% (or higher) of Aqua NC's expenses for wastewater and 89% (or higher) for water services. Witness Thill testifies that although high fixed expenses are best matched by high allocations of fixed revenues, the Company recognizes that there are critical considerations in ratemaking beyond the contemporaneous matching of the Company's revenue and expenses. *Id.* at 16. He testifies that these considerations include customer affordability and conservation. *Id.* He further testifies that these specific public policy goals in particular are better supported by ratemaking structures that recover a greater portion of costs from volumetric rates. *Id.*

Witness Thill testifies that, in determining appropriate rate designs for water and wastewater service, a balance must be struck that promotes consumption conservation while also providing the Company with a reasonable opportunity to earn its authorized rate of return on common equity. *Id.* For this reason, witness Thill states that the Company's rate proposal in this case seeks only to maintain the same ratios approved by the Commission in the recent Sub 497 rate case Order.

Junis Direct Testimony

Public Staff witness Junis testifies that the Public Staff thinks that the volumetric water rates for Aqua NC systems that are charged pass-through purchased water volumetric rates should closely match the volumetric expense incurred by the Company from the provider. Tr. vol. 5, 55. He testifies that the base facilities charges and a reasonable amount of water loss are typically included in the cost of service to determine the uniform base facilities charges. *Id.* He testifies that for purchased water providers with a uniform volumetric rate, the Public Staff recommends that Aqua NC's volumetric rate be equal to the provider's rate, plus the Commission's regulatory fee rate of 0.13%. *Id.* at 55-56.

Witness Junis testifies that the Public Staff agrees with the Commission's statements in the generic rate design proceeding, Docket No. W-100, Sub 59, that a balance should be struck between achieving revenue sufficiency and stability to ensure quality, reliability, and long-term viability for properly operated and well-managed utilities on the one hand, and setting fair and reasonable rates that effectively promote efficiency and conservation on the other hand. *Id.* at 56-57. He testifies that the Public Staff recommends an average water bill service revenue ratio of 30:70 (base facilities charge: usage charge) for Aqua NC Water, Brookwood Water, and Fairways Water customers. *Id.* at 57. He testifies that the incremental shift to higher volumetric charges sends a price signal that properly promotes efficiency and conservation. *Id.* He further testifies that the Company's total service revenues continue to increase annually, and the customer growth revenues are expected to outpace the associated variable expenses. *Id.* In addition, he testifies that the average monthly consumption per customer has been shown to be stabilizing. *Id.* He maintains that this combination of growth and stabilizing consumption makes it unlikely that the revenue instability and insufficiency the Company warns against will come to pass. *Id.*

The direct testimony of witness Junis incorporated by reference the Comments of the Public Staff filed on May 22, 2019, and the Reply Comments of the Public Staff filed on June 19, 2019, in the generic rate design proceeding in Docket No. W-100, Sub 59. *Id.* at 58. The Public Staff's May 22, 2019 Comments state on pages 32 and 33:

> By decreasing the base facility charge there is an incentive for residential customers to use water prudently and conserve.
>
> . . . .
>
> The primary beneficiaries of the lower base charges are retired persons on fixed incomes, other single and/or two person households, and customers with discretionary usage that can be reduced.

The Public Staff's June 19, 2019 Reply Comments state on pages 4 and 5, "To more effectively promote and support efficiency and conservation, the volumetric charge should be a greater proportion of the average bill. Otherwise, the cost signal is ineffective because customers have minimal incentive to reduce their water consumption."

The Public Staff's Reply Comments again quoted the 2018 Report that states, "[a]nother way to measure the strength of the conservation pricing signal of water rates is to determine how much of a financial reward (decrease in water bill) a customer will receive by lowering their water consumption from a high volume (10,000 gallons) to an average level (5,000 gallons)." (2018 Report p. 20) The EFC further states that some utilities reward customers substantially in terms of bill reduction percentage for cutting back (e.g., nearly halving the bill when customers halve their consumption) whereas other utilities provide relatively little incentive (e.g., only a 30% bill reduction). *Id.* at 58-59.

Witness Junis testifies that the present Aqua NC Water uniform water rate structure provides customers relatively little incentive to reduce their consumption because, if customers significantly reduce their usage by 50%, they experience a bill reduction of only 37.6%. *Id.* at 59. He testifies that the middle 80% of EFC-surveyed North Carolina water utilities utilizing a uniform rate provide a bill reduction ranging between approximately 32% and 48%, and the median bill reduction is 40%. *Id.*

Witness Junis further testifies if Aqua NC Water uniform residential rates had been implemented at the 30:70 ratio in the Docket No. W-218, Sub 497, rate case, utilizing the billing data and average monthly usage per customer from that proceeding, the bill reduction percentage would have increased from 37.6% to 41.2%. *Id.* at 62

Witness Junis maintains that a lower base facilities charge reduces the cost burden on customers for access to utility service before they use any service. *Id.* at 60. He states that it allows customers to have greater control over their total bills by changing their usage through improved efficiency and conservation. *Id.* Witness Junis testifies that the base facilities charge is a frequently discussed and highly controversial issue in electric, natural gas, water, and wastewater rate cases. *Id.* at 61. He contends there are advantages and disadvantages to the different base to usage ratios for the utility, rate groups, and individual customers. *Id.* Witness Junis testifies that during his Public Staff career, electric and natural gas residential base facilities charges have remained in the $10 to $15 range, while water base facilities charges have continued to increase and wastewater rates have historically been a flat rate or a very high percentage of the average residential bill. *Id.*

Witness Junis testifies that in the 2020 North Carolina Water & Wastewater Rates Report, the EFC and NCLM conducted a survey with representation from 495 of 517 rate-charging water and wastewater utilities in North Carolina.[1] *Id.* at 61-62. The median monthly base charge amount was $17 for water utilities and $19 for wastewater utilities. *Id.* at 62.

Witness Junis further testifies that neither flat rates nor metered rates with moderate to high base facilities charges properly balance revenue sufficiency and stability with the promotion of

[1] This report is just one resource in a series on North Carolina water and wastewater rates funded by the North Carolina Department of Environmental Quality's Division of Water Infrastructure (DWI) and compiled by the North Carolina League of Municipalities and the EFC at the School of Government at UNC-Chapel Hill.

efficiency and conservation. *Id.* at 63. He testifies that flat rates or low volumetric rates promote discretionary usage and wasteful practices. *Id.*

In commenting on Aqua NC's proposed wastewater rate design, Public Staff witness Junis states that the Company proposes to utilize the same ratio of base facilities charges to volumetric charges, a majority of which are monthly flat rate, as approved by the Commission in the last rate case. Witness Junis testifies that the Public Staff recommends the sewer charges to Aqua NC Sewer and Fairways Sewer customers who are also Aqua NC Water and Fairways Water customers be converted from a flat rate to a volumetric rate based on their metered water usage. Tr. vol. 5, 64. He notes that this has been considered in past Aqua NC rate cases dating back to the general rate case in Docket No. W-218, Sub 274. He states that during Aqua NC's general rate case filed on August 2, 2013, in Docket No. W-218, Sub 363, the Public Staff and Aqua NC entered into a stipulation and settlement agreement wherein Aqua NC agreed to commission a study conducted by the EFC that included the possible implementation of volumetric residential wastewater rates. *Id.*

Witness Junis states that on March 31, 2016, the EFC Report was filed jointly by Aqua NC and the Public Staff in Docket No. W-218, Sub 363A. He explains that one of the main goals of the studies was to "assess the effect on customer bills and Aqua NC revenues by implementing a volumetric wastewater rate structure or implementing a consumption adjustment mechanism water rate structures relative to the status quo." *Id. at 65-66.*

Witness Junis testifies the Public Staff would prefer to uniformly move the ratio of base facilities charge to volumetric charge toward 30:70. *Id.* at 66. However, he notes that the rate structure shift from flat to 30:70 would be expected to result in significant rate shock for some customers. He explains that while the average bill remains nearly the same, low users' bills would decrease, and high users' bills would increase. He testified as a means of mitigating rate shock while still progressing toward an effective price signal, the Public Staff recommends an incremental approach of a 60:40 ratio for Aqua NC Sewer and Fairways Sewer customers. *Id.*

Junis Cross Examination and Commissioner Questions

Witness Junis testifies on cross examination that approximately 1,000 Aqua NC Sewer residential customers already have volumetric wastewater rates as they receive bulk wastewater service from Charlotte Water. *Id.* at 78. He testifies the current rate design for those customers is 35% base facilities charge and 65% volumetric. *Id.* He further testifies the Public Staff recommends these customers have the same 60% base charge and 40% volumetric charge as the Public Staff recommends for all the Aqua NC Sewer customers that have Aqua NC Water metered service, excluding purchased water systems. *Id.*

In response to questions from Commissioner Hughes, witness Junis testifies that customers in previous Aqua NC rate cases have testified in support of volumetric wastewater billing in order to have more control over their bills. *Id.* at 120. He testifies that by switching to metered wastewater, customers that are both water and wastewater have a double incentive to control their consumption. *Id.* He further testifies based upon the NC League of Municipalities and EFC annual reports that there are not very many volumetric wastewater rates with consumption caps. *Id.* at 121-22.

Public Staff witness Junis further testifies in response to questions from Commissioner Hughes that the volumetric wastewater study in Docket No. W-218, Sub 363, justifies customers' interest in volumetric wastewater. *Id.* at 122-23. He contends that data from that study is available but is not being utilized, and that the study demonstrates that customers wanted volumetric wastewater rates and therefore justifies the shift to volumetric wastewater rates. *Id.*

Witness Junis further testifies that as of March 31, 2020, there were approximately 9,000 residential customers that would be shifted from flat rate to metered wastewater rates, which is approximately 57% of the Aqua NC Sewer flat rate residential customers.[1] *Id.* at 124.

Witness Junis testifies in response to questions from Commissioner Gray that the Public Staff's volumetric residential wastewater rates recommendation was not discriminatory as the Public Staff was taking the entire group of the Aqua NC Sewer customers that had Aqua NC water meter readings available at no additional cost, and assigning those customers to volumetric wastewater. *Id.* at 131. He further testifies that low users would have lower bills with metered wastewater billing and high users would have higher bills. He testifies that the Public Staff recommends the incremental approach of a 60/40 rate design, which keeps the base facility charge on the higher end, in order to avoid too significant of an increase in high user bills. *Id.* at 132.

On redirect examination, witness Junis testifies that of the approximately 6,000 residential customers on the Bayleaf Master water system, there are less than 800 wastewater customers. *Id.* at 140. He also testifies it was possible an Aqua NC wastewater customer who did not have Aqua NC water utility service could provide the Company that customer's water meter readings so that the Company could bill the customer using a metered wastewater rate. *Id.* at 141.

Thill Rebuttal Testimony

Aqua NC witness Thill testifies on rebuttal that he disagrees with the Public Staff's position that the average water consumption levels by Aqua NC Water and Fairways Water customers have stabilized. Tr. vol. 6, 21-22. He asserts that the Company agrees that a narrowing of the band of variation has occurred, but true stabilization would imply essentially no volatility at all. *Id.* at 23.

Witness Thill testifies that the Company does not agree that a shift to greater volumetric water rates is appropriate. *Id.* at 33. The reasons given by witness Thill for this disagreement were that it is debatable whether consumption stabilization has actually occurred and that, with regard to customer and revenue growth, the Public Staff focused only on short-term variable expenses and ignored the comprehensive cost of providing service. *Id.* at 33-35. He testifies that the Public Staff's 30/70 recommendation provides customers with an incentive for efficiency and

[1] The Public Staff filed Public Staff Late Filed Exhibit No. 2 on July 20, 2020, in the present docket. In response to Commissioner Hughes request to witness Junis, the Public Staff provided the following more detailed response:

> As of March 31, 2020, there were 15,675 ANC Sewer residential flat rate customers. Aqua proposed that approximately 149 (~1%) of those customers who live in the Woodland Farms and Rocky Ridge subdivisions be converted from residential flat rate to Carolina Water metered rates. In addition, the Public Staff recommended that 8,853 ANC Water and Sewer customers (~56%) be converted from residential flat rate to ANC Sewer metered rates. Based on the combined recommendations of Aqua NC and the Public Staff, approximately 6,673 customers (~43%) would remain residential flat rate customers.

conservation but increases the Company's concerns regarding revenue sufficiency and stability. *Id.* at 35.

In regard to wastewater rates, witness Thill testifies on rebuttal that Aqua NC does not agree with a shift to volumetric wastewater rates for many of the same reasons expressed earlier concerning the Public Staff's recommendation for a greater volumetric element for water revenues. Tr. vol. 6, 37. He testifies that volumetric wastewater rates create further instability and insufficiency in Aqua NC's revenue stream without safeguards for the Company or rate of return on common equity compensation for the added risk. *Id.* at 38. He further testifies the Public Staff's recommendation "makes no provision in the rate design for the price elasticity and creates further imbalance between the Aqua NC's highly fixed expense structure (83% short-term fixed expenses for wastewater entities as determined by the EFC Study[1]) and Aqua NC's current mixed revenue structure." *Id.*

Cross Examination Thill

On cross examination, witness Thill testifies that Public Staff Thill Rebuttal Cross Examination Exhibit 2, the 2018 North Carolina Water and Wastewater Rates Report by EFC, the NC League of Municipalities, and DEQ Division of Water Infrastructure (2018 Report), states on page 3 that of the 508 water utilities studied almost 25% of the monthly base charges for residential customers are between $11 and $15, and 25% are $16 to $20. Tr. vol. 7, 15-16. He testifies that the median monthly water base charge was $16.13. *Id.* at 17. He further testifies that page 4 of the 2020 North Carolina Water and Wastewater Rates Report stated the median monthly water base charge was $17.00. *Id.* at 19.

On redirect witness Thill testifies that the Public Staff's recommended 30/70 ratio would create additional risk that the Company will not achieve its authorized revenue requirement. *Id.* at 30.

In regard to wastewater rates, on cross examination, witness Thill observes that Public Staff Thill Cross Examination Exhibit 2 is the 2018 North Carolina Water and Wastewater Rates Report, and the three contributors are the EFC, the North Carolina League of Municipalities, and the DEQ Division of Water Infrastructure (2018 Report). Tr. vol. 7, 12. He testifies there were 396 utilities with wastewater service in this survey. *Id.* at 13. He testifies that this 2018 Report stated the median base charge for wastewater rate structures was $18.00. *Id.* at 17.

Witness Thill further testifies that Public Staff Thill Cross Examination Exhibit 3 was the 2020 North Carolina Water and Wastewater Rates Report compiled by the same three contributors (2020 Report); and the median wastewater base charge was $19.00. *Id.* at 19. Witness Thill acknowledges that the Public Staff comments filed in Docket No. W-100, Sub 59, the generic rate design proceeding, on May 22, 2019, included Exhibit 1 titled "Fiscal year 2018-2019 Wastewater Residential Flat Rate Structures" which was taken from the publication "Water and Wastewater Rates and Rate Structures" in North Carolina as of January 2019 by the EFC. *Id.* at 20. He notes that, of the 396 wastewater systems listed in Exhibit 1, there were only five flat rate wastewater government systems. *Id.* He states these five systems were Bald Head Island with a population

[1] EFC Study at 6.

served of 3,150, Cumberland County – Kelly Hills District with a population served of 920, Lake Lure with a population served of 940, Powellsville with a population served of 643, and Proctorville with a population served of 114. He testified Exhibit 1 states Powellsville bills flat rate water, Proctorville provides no water bills, and Cumberland County – Kelly Hills District does not provide water utility service. *Id.* at 21-23.

Thill Redirect Examination

On redirect examination, witness Thill testifies that Public Staff Thill Rebuttal Cross Examination Exhibit 2 lists two for-profit multi-system utilities which he thinks are Aqua NC and Carolina Water Service, Inc. of North Carolina. *Id.* at 26-27. He again maintains that any increase in the volumetric element puts the Company more at risk. *Id.* at 30. He contends that with or without the pilot program, no changes should be made to Aqua NC's existing rate design. *Id.* at 31.

The Attorney General

In his brief, the AGO states that he supports the adoption of a rate design that reduces the monthly fixed charges and instead charges customers based on metered consumption of service, as proposed by the Public Staff. The AGO states that, to encourage conservation, the Public Staff's proposed changes in Aqua NC's rate design would reduce the base charge for water service so that costs are recovered 30% from the fixed charge and 70% in usage charges. Tr. vol. 5, 74. The AGO agrees with the Public Staff that a lower base monthly charge for water service would reduce the cost burden to access service and give customers greater control over their total bills. Tr. vol. 5, 60.

Further, the AGO states that the Public Staff proposes to change the rate design for wastewater customers who receive water and wastewater services from Aqua NC. The AGO notes that Aqua NC recovers the full wastewater bill from most customers in a fixed monthly rate. The AGO describes the Public Staff's proposal to use a similar 30/70 rate design for fixed and usage charges to encourage conservation. The AGO further describes that the Public Staff proposes to mitigate the impact of the new rate design by recommending to initially recover 60% from the fixed charge and 40% in usage charges. Tr. vol. 5, 74-75.

The AGO contends that the Public Staff's proposed rate design would have several benefits:

- It would be more consistent with rate designs for electric and natural gas service.
- It would be fairer to small households.
- It would allow customers to better control their cost of service.
- It would encourage water conservation.

Finally, the AGO states that the new rate design would respond to requests that customers have posed in past rate cases and recent public hearings. *See, e.g.*, public testimonies from Eric Galamb Tr. vol. 10, 72; Wendy Stevens *Id.* at 88-89; Michelle Raymond Tr. vol. 9, 24; and Sheeba Jumma *Id.* at 120.

Conclusions

Based upon a careful consideration of the entire record in this proceeding, the Commission reaches the following conclusions discussed below regarding the contested rate design issues in this proceeding.

Aqua NC's rate design for water utility service provided to its residential customers should continue to be based on the following fixed/variable ratios which were proposed by the Public Staff and approved by the Commission in the Company's Sub 497 rate case: 40%/60% for the Aqua NC Water Rate Division; 41%/59% for the Brookwood Water Rate Division; and 44%/56% for the Fairways Water Rate Division. To further promote water conservation and to give customers more control over their monthly wastewater bills, it is appropriate to implement volumetric wastewater rates with an 80% base facility charge and a 20% volumetric charge for all the Aqua NC and Fairways wastewater customers that receive water utility service from Aqua NC or Fairways water, and for whom water meter readings are presently available, excluding the approximately 800 sewer customers in the Aqua NC Water Rate Division Conservation Pilot Program.

In determining the appropriate fixed/variable ratios for Aqua NC's water and wastewater operations, the Commission seeks to strike an appropriate balance between achieving revenue sufficiency and stability to ensure quality, reliability, and long-term viability for Aqua NC on the one hand, and setting fair and reasonable rates that effectively promote efficiency and conservation on the other hand. The Commission gives significant weight to the uncontested fact in this proceeding that short-term fixed expenses account for 83% (or higher) of Aqua NC's expenses for wastewater service and 89% (or higher) for water service. However, the Commission acknowledges the testimony in this proceeding that there are critical considerations of policy beyond the basic matching of the utility's revenues and expenses. The Commission gives significant weight to the testimony of Aqua NC witness Thill that customer affordability and conservation are two of the policy considerations that are better achieved through rate structures that recover a greater portion of costs through volumetric charges.

Public Staff witness Junis recommends a base charge to usage charge ratio of 30%/70% for Aqua NC Water, Brookwood Water, and Fairways Water stating that his recommended incremental shift to higher volumetric charges sends a price signal that properly promotes water efficiency and conservation. The Commission gives significant weight to the testimony of witness Thill that the Public Staff's higher volumetric rate design proposals provide further customer incentive for efficiency and conservation but, in so doing, they serve to exacerbate the Company's current concerns expressed in this proceeding regarding revenue sufficiency and stability. The Commission concludes that the Public Staff's rate design proposals in this case meet only one prong of the test; they encourage conservation but largely ignore Aqua NC's legitimate revenue sufficiency and stability concerns. The Public Staff's increased volumetric rate design adds greater challenges to the Company's revenue sufficiency and stability, particularly when that rate design is not coupled with corresponding revenue reconciliation measures. The Commission favors and encourages development of rate design proposals that may better achieve utility revenue sufficiency and stability while also sending appropriate efficiency and conservation signals to consumers. The Commission concludes that based upon the evidence presented in this proceeding, the Company's request to maintain the fixed/variable ratios for its water operations previously approved in the Sub 497 rate case are reasonable and should be approved.

In regard to wastewater rate design, for purposes of this proceeding, the Commission concludes that an 80% base facilities charge and a 20% volumetric charge wastewater rates are reasonable and appropriately send signals to consumers that support and encourage water efficiency and conservation and give customers more control over their monthly sewer bills. Further, the Commission gives significant weight to the testimony of Public Staff witness Junis that with metered sewer billing, low users would have lower bills and high users would have higher bills. Thus, the Commission finds that a metered sewer rate would accentuate the conservation efforts of the Aqua NC water customer that is also an Aqua NC sewer customer. However, the Commission acknowledges that smaller households may pay less under a metered sewer rate structure as noted by the AGO than larger households.

The Commission determines that, although the Public Staff's recommended 60/40 base to usage ratio for all the Aqua NC Sewer and Fairways Sewer residential customers that have Aqua NC Water and Fairways Water metered utility service would also send signals to consumers that support and encourage water efficiency and conservation, such ratio would significantly disassociate sewer revenues from sewer expenses since much of the fluctuation in water revenues is due to irrigation and other customer behaviors that have no effect on sewer operations. That is, when sewer rates are metered based on metered water usage, customers who use water for lawn and garden irrigation, for washing automobiles and other recreational usages, without an irrigation meter, for example, may pay for sewer services they do not receive. Thus, the Commission concludes that the approved wastewater rate design of 80% base facilities charge to 20% volumetric charge would appropriately support and encourage water efficiency and conservation while also recognizing that not all water usage by customers results in wastewater costs. Finally, with respect to the Public Staff's proposed wastewater rate design, the Commission finds that the Public Staff's proposed wastewater ratio would create such a significant change in Aqua NC's rate design with its 60/40 base to usage ratio would likely create further instability and insufficiency in the Company's revenue stream.

In regard to Aqua NC's proposed continuation of flat rate sewer residential rates, although such flat sewer rates are simpler to administer for the utility and would provide a more predictable and stable revenue stream for the Company, flat rates do not encourage water efficiency and conservation, which are two of the stated goals in the generic rate design proceeding (Docket No. W-100, Sub 59) nor does it sufficiently align rates to the cost of service for customers that use very little water and sewer service. Further, the AGO notes that some of Aqua NC's customers have requested that the Company implement metered sewer rates in both past rate case proceedings and in the recent public hearings. Consequently, based on the evidence provided, the Commission approves a wastewater rate design of 80% base facilities charge/20% volumetric charge for Aqua NC Sewer and Fairways Sewer residential customers that have Aqua NC Water and Fairways Water metered utility service. Such rate design is fair to both Aqua NC and its customers. The Commission acknowledges that such a rate structure will result in a higher bill for customers who do extensive irrigation and do not have a separate irrigation meter and that customers who do irrigation through irrigation meters may not experience the same conservation signal if they are not included in the Aqua NC Water pilot program. This group includes irrigation meter customers that would have been included in the Fairways Water Rate Division pilot program had the

Commission approved the pilot for that service area. For this reason, Aqua NC should evaluate and propose a separate rate for water provided through an irrigation meter in future rate case proceedings as well as rate designs that provide increased pricing incentives for reducing irrigation use for all customers who use an in-ground irrigation system.

As stated in Public Staff Late Filed Exhibit No. 2, there are 8,853 Aqua NC Sewer and 2,877 Fairways Sewer customers that have Aqua NC metered water utility service. There are 6,673 Aqua NC Sewer and 151 Fairways Sewer customers that obtain their water from providers other than the Company. These customers will remain flat rate wastewater customers. This approval of the 11,730 wastewater customers for volumetric wastewater rates is not an unreasonable preference or advantage to those residential customers, as the group includes all the Company's residential wastewater customers that received metered water utility service from the Company for which water meter readings are available monthly. Similarly, all the Company's remaining residential wastewater customers that do not receive metered water utility service from the Company with meter readings will continue to receive flat rate wastewater service.

With respect to Aqua NC's rate design for metered commercial customers, it is reasonable and appropriate for the Company's rate design for these commercial customers to be based on a metered usage rate design of 80%/20% rather than the 60%/40% ratio recommended by Public Staff witness Junis.

Finally, the Commission concludes that Aqua NC should evaluate the implementation of metered sewer rates for residential customers on customers' monthly sewer bills. Aqua NC is directed to report to the Commission on an annual basis, monthly historical consumption levels compared to the current monthly consumption levels for the customers converted from a flat sewer rate to a metered sewer rate to determine the change in consumption levels. Such report should state, at a minimum, the subdivision name, the number of customers billed (historical month and current month), monthly consumption billed (historical and current), and the sewer revenues billed (historical month and current month). Such annual report may be revised as needed in future filings as determined by Aqua NC, the Public Staff, and the Commission. Further, that Aqua NC is directed to file these reports within 45 days after the calendar year ends, beginning with the calendar year ending December 31, 2021.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30-44

Conservation Pilot Program

The evidence for these findings of fact is contained in the Application; the testimony and exhibits of Aqua NC witnesses Becker and Thill; the testimony and exhibits of Public Staff witness Junis; the testimony of public witness Becky Daniel; the late-filed exhibits filed by Aqua NC and the Public Staff at the request of the Commission at the expert witness hearing; and the entire record in this proceeding.

Summary of Aqua NC Witness Edward Thill's Direct Testimony

Aqua NC witness Edward Thill testifies on direct that the Commission, in Docket No. W-100, Sub 59, initiated "a discussion of rate design proposals that may better achieve revenue sufficiency and stability while also sending appropriate efficiency and conservation signals to consumers." In response to that request, Aqua NC (filing jointly with Carolina Water Service, Inc. of North Carolina on June 19, 2019) offered to conduct a pilot program in its next rate case to evaluate the effectiveness of an inclining block volumetric rate design. The purpose of the proposed pilot is to examine a new rate structure that could send conservation-inducing price signals to residential customers, while preserving the utility's ability for sufficient and stable cost recovery.

Witness Thill testifies that Aqua NC proposes a pilot program rather than applying inclining block rates to all of the Company's customers because there are many variabilities in an inclining block structure, from the number and size of the blocks, to the various step points, and even the absolute levels of rates necessary to accomplish its intended objective. Each of the seven largest cities in North Carolina uses an inclining block structure, and each is vastly different from the others. For example, 5,000 gallons of water in Fayetteville would cost a consumer $28.87, while Charlotte would only charge $16.89 for the same consumption. However, at 20,000 gallons, he calculates that Charlotte would charge $157.02 compared to Fayetteville's $99.62. He states that the conservation signal is clearly much stronger in Charlotte for the high-end user, but Fayetteville's design offers far less volatility for both the customer and the municipality.

According to witness Thill, there are critical assumptions made in the design that may or may not prove valid. This adds increased risk to the stability of the Company's revenues, even if sufficiency is ultimately secured by other mechanisms. The use of a pilot—actually two pilots, one for the four water system customers included in the ANC Water rate design pilot and one for the Fairways Water system customers rate design pilot—will better allow Aqua NC to analyze the results each pilot will have on a smaller scale before designing and applying any one or more final rate designs to the larger population of Aqua NC customers. The Company thinks it would be imprudent to subject the entire customer base to such a dramatic structural change without first determining the effects of that change on a smaller representative sample of customers.

Witness Thill testifies that Aqua NC focused its pilot program on systems that had the greatest opportunity for both conservation and operational relief, while also ensuring the pilot group was sufficient in size and diversity to provide meaningful results that the Company might extrapolate across its full customer base in future rate design planning. Aqua NC additionally chose systems within two separate rate entities and developed separate rate structures that will allow the Company to further assess the actual impact of the differing designs for future implementation. Each of these systems serving the service area proposed to be part of the pilot is experiencing stress to meet peak demand and could soon require capital investment if conservation is not realized in the near term.

The service areas selected were: The Cape (Fairways); Arbor Run (Aqua NC Water); Bayleaf Master System (Aqua NC Water); Merion (Aqua NC Water); and Pebble Bay (Aqua NC Water). Witness Thill states that with nearly 11,000 premises included in this pilot, the program covers approximately 13% of the Company's water customers and includes representation in each of its geographical areas. The five service areas vary significantly in size, consumption volatility, and absolute level of consumption. Witness Thill provides Thill Revised Direct Exhibit 3 which contains key statistics for customers within these pilot groups.

In describing how the blocks were derived for the pilot program, witness Thill testifies that although significant research has been conducted in the area of water rate design, no consensus exists as to an optimal structure. Each of the seven largest cities in North Carolina uses an inclining block structure, and each is vastly different from the others. Aqua NC chose the following break points in measuring customer gallons of consumption per month:

	Aqua NC		Fairways	
	From	To	From	To
Block 1	-	4,000	-	5,000
Block 2	4,001	8,000	5,001	10,000
Block 3	8,001	15,000	10,001	20,000
Block 4	15,001	Above	20,001	Above

Because this is a zero-sum exercise, witness Thill testified that there are necessarily winners and losers in any change to the pricing structure. In this case, the low volume users will experience an overall reduction in their average monthly bills at the expense of the heaviest volume users. This is consistent with the concept that although most of the utility's expenses are fixed, it is the peak demand requirement of a system's heaviest volume users that fosters the greatest incremental cost. Aqua NC's focus was on providing rate relief for customers whose usage falls within lower usage blocks and to induce conservation in those whose usage falls within higher usage block levels. The Company's challenges included:

(1) Creating sufficient rate impact to induce conservation by those taxing the system the most, while not unduly penalizing this subset of the utility's customer base;

(2) Recognizing (financially) the level of increased strain that high-volume users place on operating the system, not to mention the added water quality challenges that result from stressing existing source capacity, while still acknowledging that much of the utility's costs are in providing everyday access to water, regardless of volume consumed, and should therefore be borne by all customers;

(3) Retaining some level of conservation incentive even for the lower volume users (58% of test year bills for pilot customers were less than 5,000 gallons);

(4) Creating conservation incentive for high-volume users in Fairways where the cost of water is already comparatively low, but without giving it away to lower volume users in order to achieve the revenue requirement; and

(5) Providing for revenue sufficiency and ensuring revenue stability for the Company.

Witness Thill states that the cost per kilogallon for each block in the ANC structure increases by factors of 1.5X, 2.25X and 3.0X, with X representing Block 1 rates. Due to the low level of rates already in place for the Fairways rate entity, Aqua NC opted for a much higher ratio for that entity's Block 4. The Company's blocks for Fairways water are set to increase by factors of 2.0X, 3.5X and 5.0X, with X representing Block 1 rates. Witness Thill states that Exhibit J to the Application contains a full schedule of proposed rates for the pilot program.

Witness Thill testifies that the success of this design will not be known for some time, which adds to the Company's justification for a measured approach in using a pilot group for our first attempt at conservation rates.

Witness Thill states that Aqua NC's pilot program considers irrigation rates to the extent possible. As discussed in Aqua NC's June 28, 2019 response to Docket No. W-100, Sub 59, "Order Requiring Verified Information", separate irrigation meters are only required:

(1) in large community water systems, as defined in G.S. 130A 313(10), that regularly serve 1,000 or more service connections or 3,000 or more individuals;

(2) that were platted after July 1, 2009; and

(3) do not otherwise have a lockable cutoff valve for backflow prevention.

Witness Thill further stated that, in that same response, the Company noted that it had only 1,449 irrigation meters among its more than 80,000 water connections. Although the Company is confident that other customers irrigate through their primary connection, the Company is not able to impose specific irrigation household rates on households that validly irrigate without a separate meter.

Witness Thill states that Aqua NC's proposed pilot rates would assess Block 3 and 4 rates for all separate irrigation meters, that is, ANC customers with irrigation meters would pay the Block 3 charge for their first 15,000 gallons per month and the Block 4 rate for consumption above that threshold. Similarly, Fairways irrigation customers would pay the Block 3 rate for their first 20,000 gallons per month and the Block 4 rate above that threshold. Though Aqua NC is unable to assess separately irrigation related consumption for customers irrigating through their standard household meters, the Company expects that most irrigation-related consumption would be captured in proposed Blocks 3 and 4. The Company therefore assesses that this structure would provide equitable treatment and similar conservation signals to its irrigation customers regardless of the presence or absence of separate irrigation meters.

Witness Thill testifies that the intent of implementing an inclining block rate structure is to promote water conservation. It is, therefore, critical that the reduced customer consumption specifically intended by this pilot program is fully considered in the establishment of rates. Failure to consider the reduced consumption would assure that the Company's revenue will fall short of authorized levels.

According to witness Thill, the Company has, therefore, attempted to address revenue sufficiency and stability in two ways. First, the consumption estimates Aqua NC used to determine pricing bands in the pilot areas have been reduced to reflect demonstrated trends in price elasticity. Price elasticity measures the responsiveness of consumption to price changes. There are of course many factors that influence water demand (price, weather, and income, among others) but research---particularly on price elasticity---has been fairly extensive. The Company incorporated an elasticity of -0.3 in its consumption projections. That is, a 10% increase in consumer cost is assumed to drive a 3% decline in consumption. There has been extensive research on the subject of price elasticity in the water industry and Aqua NC established its rate based in part on the work of Sheila Olmstead and Robert Stavins, as published by the National Bureau of Economic Research in 2008, "Comparing Price and Non-Price Approaches to Urban Water Conservation". The authors conclude, based on their own work as well as a review of other large studies, that:

> "The price elasticity of residential demand varies substantially across place and time, but on average, in the United States, a 10% increase in the marginal price of water in the urban residential sector can be expected to diminish demand by about three to four percent in the short run." [Page 8]

Further in support of that figure, the UNC School of Government Environmental Finance Center in its 2009 report required by NCUC Docket Nos. W-218, Sub 274 and W-224, Sub 15, stated:

> " . . . we assumed a price elasticity of -0.3, meaning that for every 10% increase in the total bill that the customer receives, the customer responds by decreasing their water consumption by 3%. This elasticity is based on the most recent and focused analysis on water price elasticity in North Carolina."

Witness Thill states that if a consumption decline is not factored into the rate design process, any success of the program as proven by reduced consumption will necessarily be absorbed by the utility in the form of insufficient revenue and reduced return on common equity. Even if a revenue reconciliation process is approved, the burden of the initial revenue shortfall will be financed by the Company. Incorporating a consumption decline, or repression, in the calculation ensures that the utility is not working against its own interest in further funding the public policy initiative of conservation. The Company's second measure to ensure revenue adequacy and stability is the implementation of a revenue reconciliation process specific to the pilot areas. Note that this revenue reconciliation is specific to, and integral to, the pilot program. The reconciliation should be evaluated on its own merits and not in the context of any separate discussion on a proposed Consumption Adjustment Mechanism that might be applied to customers outside of the pilot program. Considering the many variables that influence water demand and that this pilot program intentionally means to increase the variability of that demand, as a general matter of fairness there must be a settlement process to ensure that neither the pilot customer group (as a whole) nor the utility is unduly harmed or enriched by this program.

Regarding the purpose of the revenue reconciliation, witness Thill testified that the ratemaking equation, put simply, is that X number of customers should pay an average of Y dollars each to produce Z dollars of revenue. Just as expenses (the driver of Z) are fixed, customer count (X) is also fixed as of a point in time. Customer count and expenses are considered only to the extent they are known and measurable as of the end of the post-test year period. The deficiency in the calculation is that the average revenue per customer (Y) requires the use of an unknowable amount of consumption. The revenue reconciliation corrects for that unknowable element of the equation. Although parties may reasonably disagree with the consumption assumptions, the intent is that the Company should receive its full authorized revenue requirement, no more and no less.

If past customer behavior fully foretold future behavior, there would be no need for a revenue reconciliation process. He states that is not Aqua NC's reality, but the customer behavior does not significantly change the utility's revenue requirement. The revenue reconciliation seeks to simply correct the deficiency in the original rate setting that was created using historic irregular consumption patterns.

Witness Thill testifies that, for illustration purposes, Thill Revised Direct Exhibit 4 provides sample revenue reconciliation calculations under three different scenarios, but the concept is consistent within each of those illustrations. Dividing the volumetric revenue requirement by the number of bills used in determining rates provides Aqua NC with the Revenue per Bill - as Authorized. Aqua NC would perform a similar calculation using actual data in the 12 full months following implementation of rates to determine the Revenue per Bill - Actual. The difference between those actual and authorized averages would define the Company's Average per Customer Usage Excess or Deficit. Dividing that Excess or Deficit by the Revenue per Bill as Authorized provides Aqua NC Excess or Deficit Rate. The Rate is then multiplied by the originally authorized volumetric revenue to determine the value of the excess or deficit.

Witness Thill states that, after allowing three months to collect and analyze the data, surcredits or surcharges would be assessed over a 12-month period in order to settle balances within one year. If the average customer bill is less than authorized, that would typically reflect that consumption was less than modeled in the original ratemaking (customers over-conserved). In this scenario, had Aqua NC known the future volumes at the time rates were set, volumetric rate levels would have been set higher. The Company therefore proposes to assess a volumetric surcharge on future consumption during the recovery period to recover any deficit.

According to witness Thill, if, however, the average customer bill is greater than authorized, that would typically reflect that consumption was more than modeled in the original ratemaking (customers under-conserved). In that case, Aqua NC proposes to refund the excess as equal credits (surcredits) to the BFC of all customers over a similar 12-month period. Any surcredit that may result is proposed to be applied to the BFC, versus volumetrically, in order to avoid diminishing the conservation signal intended to be sent to the highest volume consumers. If applied volumetrically, a surcredit would allocate a marginally larger credit to the highest users and lessen the intended conservation signal. Any over or under recovery as a result of fluctuations between the actual components of the calculation and the assumed components in determining the surcredits or surcharges would roll into the subsequent period's calculation of the excess or deficit.

Witness Thill testifies that customer growth is not included in the revenue reconciliation computation. Consistent with the explicit language of House Bill 529 (Session Law 2019-88) which was signed into law on July 8, 2019, the proposed revenue reconciliation calculation is computed based on "average per customer usage". To compute the reconciliation adjustment at a gross level of revenue, rather than at a per customer average level, would ignore that a portion of future revenue may be attributed to customers added after the test year and would therefore incorporate a projective component to the ratemaking equation. While the Company is supportive of a fully projected test year, it is not supportive of a selectively projected test year. The Company thinks that using a prospective customer count without also incorporating future cost increases should not be permitted.

WATER AND SEWER – RATE INCREASE

Witness Thill testifies that Aqua NC proposes a revenue reconciliation only for the pilot group. Consumption volatility creates a deficit or excess compared to the utility's authorized revenue and, therefore, a variation from its authorized return. Generally, the drivers of consumption volatility are shared across the Company's customer base. However, the pilot has added separate and distinct variables to purposefully drive greater consumption volatility within this subset of customers. To the extent pilot customers pay too much or too little as a result of the unknowable impact of the change in rate structures affecting only them, the benefit or detriment is confined to the pilot group and any settlement activity should similarly be borne by or inure to the benefit of only that subset of customers.

Witness Thill testifies that implementation of a revenue reconciliation for the pilot group is in the public interest. The purpose of the revenue reconciliation is to correct for an unknowable component of the initial ratemaking calculation. The Commission will have already ruled on a revenue amount that is reasonable and appropriately within the public interest. If the consumption levels were knowable, there would be no need for a reconciliation process as the rates would have been set at the appropriate level to allow for full revenue recovery by the utility. The revenue reconciliation process simply allows the utility to achieve the authorized amount already deemed in the public interest.

Witness Thill further states that a revenue reconciliation is integral to the pilot program. If the utility's revenue sufficiency cannot be guaranteed within this conservation program, the Company feels it would be imprudent to accept, on behalf of its shareholders, the additional financial exposure that this or any other conservation program might create. If Aqua NC is not afforded an ability to true up its revenue periodically throughout the pilot program, the Company reserves the right to withdraw its request to implement the proposed pilot rates and, instead, requests that the consolidated rate design be applied to all customers within their applicable rate entities.

Summary of Aqua NC Witness Thill's Testimony in Response to Cross-Examination, Questions from the Commission, and on Redirect

In response to questions from Public Staff Attorney Grantmyre on cross-examination regarding the Company's proposed conservation pilot program, witness Thill agreed that reducing the Company's water base facility charge would help low income persons or persons using low amounts of water, if that was the only consideration. He went on to state that "...it's a balancing act. So to provide more relief at the lowest block, you've got to charge the highest block considerably more. And our analysis was showing that some of those people in the higher blocks were already having an increase of doubling their rates." Tr. vol. 4, 71. Witness Thill stated that the pilot systems are representative of the type of systems where the Company is trying to induce conservation. Witness Thill accepted a premise from the Public Staff that, subject to check, that the average water usage is 7,420 gallons per month for the four water systems in the Aqua NC Water Rate Division and that average consumption for the remainder of the Uniform Water Systems calculates to 4,149 gallons per month per customer. Witness Thill stated that it makes sense that the pilot program has a much higher usage, since those are the customers from whom the Company is trying to get conservation.

Witness Thill was asked to read into the record the following data request responses provided by the Company during discovery as set forth in Public Staff Thill Direct Cross Examination Exhibit 1:

> The Company did not perform a scientific study to determine systems for inclusion in the conservation pilot but rather relied on the subjective input of the operations team that manage the challenges of these stressed systems each and every day. Bayleaf and The Cape were early nominations for inclusion due to their known operational challenges, particularly during irrigation season, as well as their vast sizes that might allow for greater conservation impact. Arbor Run, Merion and Pebble Bay each experiences operational challenges as well and were added to the pilot in order to add further diversity in geographic location and customer consumption patterns.
>
> Regarding operational cost savings, the Company has assumed a certain level of repression in the consumption rates of the pilot customers as explained in Testimony. The cost savings associated with that reduced volume flows through variable operating expenses such as power and chemicals in the consumption adjustment factor.
>
> Projected future captain (sic)[1] spend is not a direct consideration in the general rate case. As such, avoidance of any such potential future capital costs was similarly excluded from the rate case considerations.

On cross-examination, witness Thill further testified that the Company is requesting approval of a revenue reconciliation process in conjunction with its pilot program that is "conceptually similar" to a CAM. He responded with an explanation as to why the Company does not think it is appropriate to include projected customer growth in the revenue reconciliation process.

On redirect, witness Thill testified that one of the considerations which caused the Company to withdraw its request for a CAM in this case was timing in the middle of the rate case which made it infeasible to move forward with a CAM. In addition, witness Thill noted the Public Staff's stated opposition to Aqua NC's proposed CAM in its testimony. Witness Thill also stated that the revenue reconciliation procedure was an integral part of the Company's proposed pilot program because there are so many moving parts. In addition, he testified that the Commission cited the specific language of the CAM legislation in its rulemaking docket, ". . . which talks about average per-customer use, as opposed to total revenue, which has been the position of the Public Staff." Similar to its objections to approval of a CAM in this case, witness Thill testified that the Public Staff also ". . . objected to the pilot overall, and specifically to the revenue reconciliation." He further stated that the Company's revenue reconciliation, as proposed for the pilot program, does not include an adjustment for customer growth; instead, it measures on the average per-

[1] The proper word used by witness Thill was "capital".

customer use, which he believed to be consistent with the Commission's recent ruling in the CAM rulemaking. Tr. vol. 4, 83-85.

Regarding the Company's high percentages of fixed costs of providing water and sewer utility service and how that factors into the Company's proposed rate design, witness Thill stated that:

> Well, there's a balance that needs to be maintained. You know, if the only consideration was conservation, then it should be fully volumetric. If the only concern was the stability of revenues for the utility, then it should be flat rate. There has to be a balance somewhere in between. And so as we look at our expenses being primarily fixed for both water and sewer, you know, we've got 90 percent -- or almost 90 percent of our costs on the water side are fixed, but only 40 percent of our current revenue stream is fixed on the water side. And that's an imbalance that puts us at risk. Tr. vol. 4, 86.

In response to questions from Commissioner McKissick regarding price elasticity and repression, witness Thill described in detail why the Company focused on the National Bureau of Economic Research (NBER) Report in developing the proposed pilot program. See Tr. vol. 4, 92-95. Witness Thill also described in detail how the revenue reconciliation process would work. Tr. vol. 4, 95–97. In response to a question as to whether Aqua NC intends to include in its calculation those carrying costs for either the deficit or excess due to the revenue reconciliation for the pilot program, witness Thill replied that:

> I don't think we've gone on record as to say whether or not we believe there should be a carrying cost adjustment. I would just suggest that, as a matter of fairness, that if the Commission decides that there should be a carrying cost, that it go either way. So that to the extent there's an excess or a deficit, there would be a carrying cost assigned in a similar manner.

Tr. vol. 4, 97.

When asked by Commissioner McKissick to address how long Aqua NC would reasonably anticipate that the pilots would last and what the timeline would be, witness Thill responded as follows:

> That's a very fair question. In fact, we've had some of those conversations with the Public Staff as well. This, of course, in order to get usable data, is going to take some period of time. And it's going to take -- you know, we use a three-year average currently in the ratemaking because seasonality will have impacts, and that will also have impacts with regards to what we see in the consumption patterns of these pilot program individuals.
>
> So we would suggest that this has to last at least two to three full cycles in order to get usable data. And, you know, so this is something that should be evaluated, we believe, as part of, you know, future rate cases. So we have -- Aqua has indicated that we're likely to be back for rates on a fairly tight schedule going forward, as

> tight as 15 to 18 months. That won't give us two cycles in the next case, so it's probably, you know, two cases ahead of us where we can be in a position to provide some data to determine whether or not the pilot should either be terminated or expanded to the entire population, or just tweaked. Tr. vol. 4, 98-99.

In response to questions from Commissioner Hughes regarding the availability of information concerning the percentage of Aqua NC's pilot project customers that rely on direct draft or paperless delivery -- paperless billing, witness Thill agreed to file a late-filed exhibit regarding the percentages of the Company's customers that currently have direct draft or paperless delivery.

In response to additional questions from Public Staff Attorney Grantmyre, witness Thill stated that the Company's proposed pilot, if implemented, would delay implementation of inclining block conservation rates for all of Aqua NC's customers in order to allow time for the Company to understand how such rates might be implemented for all customers and what that impact might be. When asked if the Company could, in its next rate case, file for increasing block rates for all the customers and introduce a CAM at the same time, witness Thill replied that:

> We could. I don't know what that structure would look like, because we just don't have that kind of data yet. Again, I'll point to the analysis just between, I believe it was Fayetteville and Charlotte, that the two programs are very different, both in their BFC as well as their volumetric element. And so they have a very different conservation signal. And part of that might have to do with, you know, any number of factors, the socioeconomic piece of those two groups. Tr. vol. 4, 113.

On redirect by Aqua NC's counsel, witness Thill expounded upon why the revenue reconciliation mechanism is crucial to the Company's willingness to put this pilot project into effect. Tr. vol. 4, 114–115. Witness Thill also testified that the Company's situation would be exacerbated if the Commission were, in effect, to approve both the pilot and the Public Staff's recommended rate design of 30%/70% for water and 60%/40% for sewer. He stated that:

> And the Public Staff's position would continue to drive greater variability in revenue, and at the same time do that with the intent of creating further conservation, which not only makes it more variable, but also less likely to achieve the three-year average consumption levels that have been used to determine rates. Tr. vol. 4, 116.

In further amplification of his response to a previous question asked by Attorney Grantmyre, witness Thill testified that, while Aqua NC could propose to implement inclining block rates for all of its customers in its next general rate case, that is not what the Company recommends in this case. The Company wants to implement its proposed conservation pilot program. Witness Thill further stated that:

> ...We want to start getting information. And, you know, we could do as Mr. Grantmyre said and propose a Company-wide version next time. We could have proposed a Company-wide version today. But the reality is that we don't know what that would look like. And if you were to talk to the City of Charlotte, if you were

> to talk to the City of Fayetteville, they would give you two different answers because they have two very different structures themselves.
>
> We did talk to the City of Raleigh and got some of their concerns or considerations as they went through some of their rate design elements. I know Mr. Becker had those conversations. So, you know, we've done some of the research. Ultimately, the answer is we're not sure. You know, we're just trying to get the best information available today to start this process. You know, the longer we wait -- and this is part of Mr. Grantmyre's point, I believe, is that the longer we wait, the less effective it is. So we need to start getting some information, and that's why we've got the pilot out there today. Tr. vol. 4, 116-117.

In response to a further question from Aqua NC's counsel, witness Thill agreed that the Public Staff could itself have proposed a Company-wide rate design that included inclining block rates but did not do so. Witness Thill further stated that in the Commission's rate design rulemaking proceeding (Docket No. W-100, Sub 59), the Public Staff did recommend that block rate design is the optimal way to go. Witness Thill asserted, however, that the Public Staff made no such proposal in this case. He further stated that, even more interesting, is that the Public Staff proposed a 30%/70% rate design in this case assuming that the CAM was either rejected by the Commission or withdrawn by the Company. But here, the Public Staff put forth a proposal that would create greater uncertainty with a greater volumetric number for Aqua NC, but conditioned it on that there not be a revenue adjustment mechanism to provide a floor for the Company. Witness Thill testified that while there is reference in the Public Staff's testimony that repeats some of the language of the Commission about trying to create conservation and efficiency while also measuring up against revenue stability and sufficiency, "I don't see that as a two-sided equation coming from the Public Staff's version." Tr. vol. 4, 117-19.

Summary of Public Staff Witness Charles Junis' Testimony

Public Staff witness Charles Junis testifies that, in its application and as detailed in the direct testimony of Aqua NC witness Edward Thill, the Company has proposed a "Conservation Pilot Program" to implement tiered inclining block volumetric rates, including separate irrigation rates, to be charged to residential water customers in the Arbor Run, Merion, Pebble Bay, and Bayleaf Master System service areas (Aqua NC Water rate entity) and The Cape service area (Fairways Water rate entity). As part of the proposed Conservation Pilot Program, the Company incorporates a projective repression of usage levels below the three-year average already subjected to the Company's proposed Conservation Normalization Factor. In addition, the Company requests a revenue reconciliation to be computed within the pilot program that would guarantee that the revenue requirement per bill be recovered in rates.

Witness Junis testifies that the Public Staff has concerns about the practicability, fairness, and value of the proposed pilot program. While well-designed inclining block rates can effectively promote conservation, the Public Staff has identified the following concerns with the Company's proposed pilot program: (1) the pilot is a limited and unrepresentative sample of residential customers, (2) would not "provide meaningful results that we might extrapolate across the Company's full customer base in future rate design considerations" as the Company claims, (3) reverts to ratemaking with system-specific rates as opposed to uniform rates, (4) ignores the overlapping purpose of House Bill 529 and Commission Rules R7-40 and R10-27, (5) the potential benefit(s) of the program may be outweighed by the valuable personnel resources of the Company, Public Staff, and Commission required to implement and track the pilot, and (6) nearly guarantees service revenues, thus reducing risk. In addition, singling out groups of customers would be discriminatory and potentially prejudicial if those customers' bills increased significantly under the inclining block rates in comparison to other customers charged uniform usage rates, or vice versa for low usage customers.

Witness Junis states that Company witness Thill states the following regarding the sample of customers chosen for the pilot program:

> The use of a pilot---actually two pilots, one for the four water system customers included in the ANC Water rate design pilot and one for the Fairways Water system customers rate design pilot---will better allow us to analyze the results each pilot will have on a smaller scale before designing and applying any one or more final rate designs to the larger population of Aqua customers. The Company believes it would be imprudent to subject the entire customer base to such a dramatic structural change without first determining the effects of that change on a smaller representative sample of customers. *Id.* at 16.

According to witness Junis, Thill Revised Exhibit 3 provides statistics for the systems proposed for the pilot program. From this table, it is clear that these are above average or high-usage systems that are not representative of uniform water residential customers. Company witness Thill states, "I focused our program on systems that had the greatest opportunity for both conservation and operational relief . . . ." and "Each of these systems is experiencing stress to meet peak demand and could require (potentially near-term) capital investment if conservation is not realized." In response to a Public Staff data request regarding operational relief, expense savings, and avoided costs, the Company stated that it relied on subjective input from operations staff, "cost savings associated with the reduced volume [repression] flows through variable expenses such as power and chemicals in the consumption adjustment factor," and because "[p]rojected future capital spend is not a direct consideration in a general rate case" then "avoidance of any such potential future capital costs was similarly excluded from the rate case considerations." The potential benefits are subjective based on the limited supporting documentation referred to above. The Company appears to describe operations in crises due to high volume users on one hand, yet on the other hand, fails to meet its burden to describe how the pilot may result in relief to these systems or an avoidance of capital expenditures.

Witness Junis testifies that the Company proposes the use of a price elasticity constant that is described in two sources referenced on page 22 of the direct testimony of Company witness Thill and is not specific to Aqua NC's customer base, to prospectively reduce consumption based on the proposed price increase to the volumetric rate within the inclining block rate structure. While a price elasticity of -0.3 may be expected on average, the projective repression applied to the customer consumption data is in addition to the Company's Conservation Normalization Factor. The Company's proposed factor most certainly includes some degree of price elasticity impact as Aqua NC has increased its rates three times during the analysis period of three-year averages from October 1, 2008, to September 30, 2019, (updated to April 1, 2009, to March 31, 2020). In addition, the repression ignores the socio-economic demographics of the systems that may make them less sensitive to price signals. The Company's combination of the price elasticity, Conservation Normalization Factor, and failure to take into account socio-economic demographics is likely to result in the overestimation of the expected consumption reduction.

Witness Junis states that while limited in scope to the pilot program, the proposed revenue reconciliation is materially the same as the proposed CAM. Similar to the Company's reservation of the right to withdraw its request for a CAM, Company witness Thill states, "If is not afforded an ability to true-up its revenue periodically throughout the pilot program, the Company reserves the right to withdraw its request to implement the proposed pilot rates and, instead, requests that the consolidated rate design be applied to all customers within their applicable rate entities." This creates a scenario rife with uncertainty in which any variation to the Company's proposed revenue reconciliation or the CAM could prompt the Company to withdraw the request and it is unclear when that might happen. This uncertainty could drastically impact interrelated issues such as the pilot program, CAM, rate design, and rate of return. Therefore, in order that the pilot request and its potential impact on other issues may be properly investigated and evaluated, the Company should not be permitted to alter its request indefinitely.

Witness Junis concludes his testimony by stating that the Public Staff recommends that the Commission deny the Company's proposal for a pilot program.

Summary of Public Staff Witness Junis' Testimony in Response to Cross-Examination, Questions from the Commission, and on Redirect

In response to questions from Commissioner McKissick, Public Staff witness Junis testifies that, in his opinion, because the Company has targeted high-irrigation customers, or high-consumption customers:

> . . .you cannot extrapolate those findings to the rest of the customer base . . . . So how can you implement a pilot and then extrapolate that information from these customers that have abnormally high usage and say, well, these low-consumption customers are also going to see some form of decrease or extrapolate those findings? Tr. vol. 5, 81.

Witness Junis further states that, in his opinion, a pilot should be a representative sample so that you can extrapolate those findings to the rest of the customer base. Now that the Company has explained or changed its proposal to define a period of time to run this pilot, that is another reason to deny it. Because you are now making a decision that not only impacts this rate case, but possibly one or two more rate cases to keep that pilot around long enough to get enough data. In response to Commissioner McKissick, witness Junis expounded at length with criticisms of the Company's proposed conservation pilot program, including criticisms of the revenue reconciliation process. Tr. vol. 5, 80–95.

In particular, with respect to Aqua NC's proposed revenue reconciliation process, witness Junis contends that the revenue reconciliation process proposed by Aqua NC eliminates risk for the Company by fully guaranteeing the revenues approved in Aqua NC's rate case as determined by the billing analysis. Witness Junis proposes a two-prong test to address this concern. The first prong would be whether the actual average consumption per customer decreased. He contends that this test would adhere to the requirements of the mechanism pursuant to N.C.G.S. § 62-133.12A "... to track and true-up variations in average per customer usage from levels approved in the general rate case proceeding...." The second prong would be whether the total actual usage, either in terms of consumption or the amount of revenues corresponding to the consumption, decreased. Witness Junis states if both prongs of the test are met a surcharge should be implemented because Aqua NC would not be collecting the revenues anticipated in the Commission-approved rate design. He notes that if Aqua NC has experienced a decrease in average consumption per customer but its revenues exceed the revenue requirement approved in the rate case, a surcharge would not be needed because customer growth would have offset the decrease in consumption. Witness Junis further states that if the average consumption per customer has increased and revenues have also increased, customers should receive a surcharge credit. Finally, witness Junis states that in the average consumption per customer has increased but revenues have decreased, no surcharge would be required because the statutory requirement to address average consumption per customer has been met.

In response to a question from Commissioner Brown-Bland as to whether the Public Staff would be agreeable to the proposed reconciliation if it were based on the total revenue requirement in the pilot area, witness Junis testified that he agrees that the revenue requirement would be the threshold or the target for the reconciliation..

In response to questions from Commissioner Duffley, witness Junis testifies that the Public Staff, asserting the alleged flaws of the Company's pilot proposal, recommended a small shift to variable rates in this case, including a shift to metered wastewater that has been considered for years and years, but has not been implemented. He also states that implementation of either a more expansive inclining block rate or rate design that promotes conservation should happen in the Company's next rate case and that it would be better if it was implemented across the board and with a CAM that considers the full picture.

In response to questions from Commissioner Gray regarding inclining block water rates, witness Junis testifies that, to his knowledge, the Commission has not yet approved use of such rates for any water utilities in North Carolina. Witness Junis also states that inclining block rates can penalize large families which have a higher level of non-discretionary usage, depending on the design of the blocks, so that they pay significantly more. There can also be situations where unrecognized water leaks develop which can result in a "giant" bill. Tr. vol. 5, 107–110.

Commissioner Clodfelter asked witness Junis a series of questions related to development of a proper experiment or pilot program, which would need to reflect diversity of geography, diversity of weather conditions, diversity of economics, and diversity of demographics. Witness Junis responded in detail. See Tr. vol. 5, 113–17. In particular, witness Junis agrees that case studies exist on inclining block rate designs that could be reviewed and analyzed against the profile of the Aqua customers and system operations. However, he notes that any rate design implemented for Aqua NC would likely be "tweaked" as actual experience is obtained. Witness Junis states that Aqua NC would be required to maintain consumption billing data in 1,000 gallons blocks for the Public Staff and Aqua NC to properly evaluate and structure an inclining block rate structure.

Witness Junis responded to multiple questions from Commissioner Hughes which related to rate design issues. See Tr. vol. 5, 118–130.

In response to questions from Public Staff Attorney Grantmyre, witness Junis testifies that, if the Company came back in its next rate case and proposed inclining block rates for all its customers in all areas of the state, and all the customers had the same inclining blocks, that would meet the criteria geographically, socioeconomically, usage-wise, and demographically, because if everyone is included in that rate design, it is then representative of all of them. Witness Junis further states that instead of the pilot program, the Public Staff would prefer that statewide inclining block rates be considered in the next rate case. He later modifies that statement regarding statewide inclining block rates by saying that "I think we would consider slightly modified inclining block rates for the different rate entities." Tr. vol. 5, 139.

Summary of Aqua NC Witness Edward Thill's Rebuttal Testimony

Aqua NC witness Thill testifies in rebuttal to the testimony offered by Public Staff witness Junis. Witness Thill states that on March 20, 2019, the Commission issued an Order Establishing Generic Proceeding and Requiring Comments in Docket No. W-100, Sub 59 (W-100, Sub 59, Order). The Order made the Public Staff, CWSNC, and Aqua NC parties to the proceeding and required the parties to file initial comments to include "a discussion of rate design proposals that may better achieve revenue sufficiency and stability while also sending appropriate efficiency and conservation signals to consumers." Witness Thill testifies that Aqua NC's proposed conservation pilot program is a direct response to the Commission's goals as stated in that docket.

Witness Thill responds to each of the concerns expressed by Public Staff witness Junis regarding the Company's conservation pilot program. He testifies that the first two concerns expressed by witness Junis were that (1) the pilot is a limited and unrepresentative sample of residential customers and (2) the pilot would not "provide meaningful results that we might extrapolate across the Company's full customer base in future rate design considerations" as the Company claims.

Witness Thill replies that because the Fairways Water system is one large system in its own rate division, the entirety of that rate entity is included in the proposed pilot and, therefore, the Public Staff's concern regarding limitation and reasonable representation is not relevant for that portion of the pilot. Concerning the four systems in the Aqua NC Water Rate Division pilot, witness Junis states in reference to Thill Revised Exhibit 3: "From this table, it is clear that these are above average or high-usage systems that are not representative of uniform water residential customers." Witness Thill states that Public Staff's comment seems to imply that conservation programs should be equally focused on both high-usage and low-usage systems. Introducing a block structure for systems with consumption below the block limits provides no information on the cause-and-effect relationship of pricing and conservation. Additionally, conservation-inducing pricing for low users places a greater economic burden on those who can least afford it. These households are already likely to have minimal discretionary usage and are therefore less likely to experience any financial benefit of conservation. Alternatively, Aqua NC's conservation pilot is intended to affect the discretionary users that are more prevalent in the high-usage systems.

Witness Thill testifies that the largest proposed participant system in the pilot is the Bayleaf master system in Wake County, serving approximately 6,000 households. Although that system would appropriately be deemed a high-usage system with average usage of over 7,300 gallons per month (gpm), the customer base is not a homogenous group of high-consumption households. Thill Revised Exhibit 3 introduces the concept of a volatility ratio that attempts to identify the magnitude of discretionary consumption in each household. The Exhibit shows that, while 26% of Bayleaf users have significant volatility (defined as having a volatility ratio greater than 4.0), only a slightly lesser 20% of that system's users have minimal volatility (ratio of less than 1.5). To give perspective to that measure, witness Thill stated that, if we assume solely for purposes of this exercise that the average household uses 4,000 gpm on a non-discretionary basis, the low volatility user might spike to 6,000 gpm in a given period while the high volatility users would spike to 16,000 gpm or more. The volatility ratio exposes those customers with the greatest capacity for conservation, as evidenced by their own consumption, and are the target of this conservation pilot. Of the full year population of customers, 19% had low volatility and therefore low discretionary consumption. This group would be the primary benefactor of the initial conservation rates as they have a lower than average consumption pattern and would therefore benefit from the reduced volumetric cost of Block 1 consumption with limited exposure to increases in Blocks 2-4.

Witness Thill testifies that witness Junis identifies the pilot as being limited, but that is the very nature of a pilot. Junis Exhibit 7 shows total measured monthly bills for Aqua NC Water customers during the test year of 745,138. Thill Revised Exhibit 3 shows total test-year bills for those same Aqua NC customers included in the pilot as 76,152, excluding Fairways customers at The Cape. Whereas any pilot is inherently limited, Aqua NC's proposed pilot covers 10% of Aqua NC Water and 100% of Fairways Water residential customers. This level of coverage, particularly in areas of high consumption, should provide worthful data on the effectiveness of the proposed design and valuable customer behavior information that can be used to refine the rate structure and apply it to the larger customer population in future cases.

Witness Thill next addresses the Public Staff's third concern – that the pilot reverts to ratemaking with system-specific rates as opposed to uniform rates. According to witness Thill, this objection by the Public Staff would preclude any pilot program. Each of the seven largest cities in North Carolina uses an inclining block structure, and each is vastly different from the others. In applying a conservation rate to realize a static revenue requirement, higher consumption customers will subsidize the cost of lower consumption users. The average revenue requirement calculated to be realized from the entire population of "piloted" communities is calculated to be the same as would be realized across non-pilot communities. Witness Thill testifies that there is no singular "correct" model and Aqua NC thinks that both customers and the utility are better served by testing this concept on a representative few systems before exposing the entire customer base to a drastic change in rate structure with many unknown consequences.

Witness Thill addresses the Public Staff's fourth concern that the pilot ignores the overlapping purpose of House Bill 529 and Commission Rules R7-40 and R10-27 as follows. Contrary to this statement, Aqua NC's pilot program embraces House Bill 529 by making a condition of its pilot that a revenue reconciliation process also be implemented. A program that intentionally reduces consumption but does not factor that reduction (repression) into ratemaking assigns the full cost of conservation to the utility and directly compromises its opportunity to achieve the Commission authorized return. On the other hand, a program that assigns a repression element, an unknowable variable, without a reconciliation feature adds significant risk to both customers and the utility and is in the interest of neither.

The Public Staff's fifth concern is that potential benefit(s) of the program may be outweighed by the valuable personnel resources of the Company, Public Staff, and Commission required to implement and track the pilot. Witness Thill stated that, again, this objection by the Public Staff would seem to preclude any pilot program. He noted that witness Junis stated that:

> The potential benefits are subjective based on the limited supporting documentation referred to above. The Company appears to describe operations in crises due to high volume users on one hand, yet on the other hand, fails to meet its burden to describe how the pilot may result in relief to these systems or an avoidance of capital expenditures.

According to witness Thill, this argument seems to require definitive quantification of savings that might be had from a pilot that has never been implemented, essentially requiring past proof of future benefits. Aqua NC approached its pilot assuming that certain "truths" already exist regarding the benefits that reduced consumption might create, as well as the impact that a properly constructed block structure might have on conservation. Those "truths" would seem to be echoed in the following Comments of the Public Staff filed on May 22, 2019, in Docket No. W-100, Sub 59:

> Decreased usage is a decrease in demand. In addition to the revenue and short-term variable expense effects, decreases in demand can delay or even eliminate the need to undertake capital-intensive projects such as the expansion of plant capacity. For the larger privately-owned public utilities, this can add up to thousands or possibly millions of dollars of savings that would otherwise be booked. (Pages 2-3)
>
> . . . decreased usage results in decreased pumping which, in turn, increases the longevity and reliability of wells. (Page 3)
>
> Due to higher prices for greater consumption, increasing block rates also send a strong conservation signal to customers. During times when a system's capacity may be limited, such as during periods of increased irrigation, the demand increase is captured by a higher cost for above average water usage. This increased cost may encourage customers to focus on conservation measures. (Page 8)
>
> When the demand exceeds the well pumping supply and effective storage capacity, the customers can experience low pressure, degradation of water quality, and/or a complete outage. (Page 27)
>
> Based on the foregoing review of rate structures, and based on its experience and expertise, the Public Staff is of the opinion that, to best balance the objectives of sufficient and stable revenue for the utility with appropriate signals to consumers that support and encourage efficiency and conservation, water and wastewater rates should be volumetric with one or more increasing blocks. (Page 31)

Witness Thill states that it is important to note that the Company's conservation pilot is proposed in response to the Commission's request of Docket No. W-100, Sub 59. Benefits of a block structure as opined by the Public Staff in the quoted passages include decreased capital costs, better access to water, reduced pressure concerns, and better quality. Each of these benefits inures to the customer. The utility will hopefully experience operational relief, which was a key component of Aqua NC's system selection, but that is still a benefit to the customer. The economic impact to the utility is actually a reduction of future capital investment and therefore a reduction of future earnings.

According to witness Thill, Aqua NC is supportive of the Commission's conservation initiative and appreciates its recognition that conservation brings with it challenges to the sufficiency and stability of the utility's revenue. The Company has attempted to design its pilot in a manner that encourages conservation without sacrificing its own authorized earnings. To that end, the Company has assumed price elasticity using information gathered from the 2009 report of the UNC School of Government Environmental Finance Center required by NCUC Docket No. W-218, Sub 274 and W-224, Sub 15:

> . . . we assumed a price elasticity of -0.3, meaning that for every 10% increase in the total bill that the customer receives, the customer responds by decreasing their water consumption by 3%. This elasticity is based on the most recent and focused analysis on water price elasticity in North Carolina.

Witness Thill testifies that witness Junis objects to the use of that elasticity measure since it "is not specific to Aqua's customer base" even as Aqua NC's operations span 51 counties across all of North Carolina. Witness Junis' challenge would, again, essentially require past proof of future events. However, witness Junis then seems to soften his stance somewhat in stating:

> While a price elasticity of -0.3 may be expected on average, the projective repression applied to the customer consumption data is in addition to the Company's Conservation Normalization Factor. The Company's proposed factor most certainly includes some degree of price elasticity impact as Aqua has increased its rates three times during the analysis period of three-year averages from October 1, 2008, to September 30, 2019, (updated to April 1, 2009, to March 31, 2020).

Witness Thill states that this statement conflates two independent measures. The Conservation Normalization Factor measures the reduced consumption experienced in the past, independent of the reason for that reduction. Repression is a research-based projection of the amount that future consumption is likely to decline directly as a consequence of a change in rates. Without providing justification as to how these concerns, individually or in combination, would yield such a result, witness Junis concludes:

> The Company's combination of the price elasticity, Conservation Normalization Factor, and failure to take into account socio-economic demographics is likely to result in the overestimation of the expected consumption reduction.

Regardless of the validity of witness Junis' argument either in totality or of any component, witness Thill states that his conclusion of an overestimation of consumption reduction could prove true. Such a statement should not be regarded as a softening of the Company's position but rather an acknowledgement that the modeled repression of -0.3 most certainly will not exactly be experienced. Aqua NC does not know if it will be more or less, but -0.3 is the best estimate the Company has today of an unknowable future event. As a result, actualized repression will result in the Company receiving more or less revenue than intended by the Commission – unless a reconciliation measure is adopted in concert with the pilot as discussed earlier.

Regarding the Public Staff's sixth concern that the pilot nearly guarantees service revenues, thus reducing risk, witness Thill states that, while Aqua NC has conditioned its conservation pilot program on the implementation of a related revenue reconciliation process, that reconciliation acts as a safeguard for both customers and the utility. Aqua NC's intent within this program design is to encourage conservation without sacrificing its own opportunity to earn its authorized earnings. Implementing a pilot rate design that fully satisfies the totality of the Public Staff's objections would result in a design encompassing 100% of Aqua NC's customer base, with no elasticity assumption and no revenue reconciliation.

In addition, the Public Staff asserts that singling out groups of customers would be discriminatory and potentially prejudicial if those customers' bills increased significantly under the inclining block rates in comparison to other customers charged uniform usage rates, or vice versa for low usage customers. According to witness Thill, this standard, similar to other objections raised, would preclude any effective pilot from implementation. All pilots, by definition, only apply to a subset of the customer base, while a pilot must necessarily create significant increases or decreases to be considered effective.

Witness Thill further testifies that any change to Aqua NC's rate structure will necessarily create "winners" and "losers", some intentionally and some by association. This objection is another argument in favor of the Company's revenue reconciliation proposal since it specifically ensures that any excess or deficit in revenue generated by the pilot is returned to or collected from only those customers that contributed to that excess or deficit.

Witness Thill testifies that the Company has proposed its pilot in response to the Commission's interest in water efficiency and conservation. The pilot covers a representative group of users in mostly high-volume, operationally challenged systems that have significant opportunity for benefit and where consumer behavior can best be evaluated in terms of the effectiveness of conservation price signals. The proposed revenue reconciliation process is an integral element of this pilot program providing a critical safeguard for both the customers and the Company. If the Commission determines that the revenue reconciliation process as proposed should not be approved, witness Thill stated that the Company would respectfully and regrettably withdraw its proposed conservation pilot.

Summary of Aqua NC Witness Thill's Testimony in Response to Commission Questions

In response to a question from Commissioner Duffley, witness Thill testifies that, if the Commission modified the pilot's revenue reconciliation process, he could not commit on behalf of Aqua NC that the Company would proceed with the pilot.

Commissioner Brown-Bland asked witness Thill if the Commission capped the pilot program to the revenue requirement, would the Company be agreeable to that? Witness Thill responded in detail to the question and concluded by stating that the "...short answer is that I don't think the Company would agree to that." Tr. vol. 7, 61. Witness Thill also testifies that he could not speak for the Company in response to other hypothetical-type questions asked by Commissioner Brown-Bland related to the pilot program.

Summary of Aqua NC Witness Thill's Rebuttal Testimony on Redirect

In response to questions from Aqua NC's counsel on rebuttal redirect examination, witness Thill testifies that the Public Staff had an opportunity to file a rate design based upon inclining block rates but did not do so in this case. Instead, the Public Staff proposed to increase the volumetric elements for both water and wastewater service. Witness Thill states that any increase in the volumetric element of rates increases the Company's risk of recovering its allowed return and rates. A CAM would, to some degree, alleviate that concern.

Commission Conclusions Regarding the Conservation Pilot Program

Based upon a careful consideration of the entire record in this proceeding, the Commission concludes that it is reasonable, appropriate, and in the public interest to approve implementation of the Conservation Pilot Program by Aqua NC for residential customers in four of the five service areas proposed by the Company: Arbor Run; Bayleaf Master System; Merion; and Pebble Bay. For the reasons set forth below, the Commission declines to accept Aqua NC's proposal to implement a Conservation Pilot Program for The Cape service area.

By Order entered in Docket No. W-100, Sub 59 on March 20, 2019, the Commission initiated an Investigation of Rate Design for Major Water Utilities, requesting, in pertinent part, "a discussion of rate design proposals that may better achieve revenue sufficiency and stability while also sending appropriate efficiency and conservation signals to consumers." Aqua NC's proposed conservation pilot program is a direct response to the Commission's goals as stated in the generic docket. The proposed pilot program has been rigorously and comprehensively reviewed by the Public Staff and the Commission and, notwithstanding the position taken in opposition thereto by the Public Staff, the Commission concludes that the use of a pilot program in a portion of the Aqua NC Water Rate Division will better allow Aqua NC, the Public Staff, and the Commission to analyze the results the pilot will have on a smaller scale before designing and applying any one or more final rate designs to the larger population of the Company's customers. Further, the Commission determines that exploration of rate design structures through pilot programs is appropriate because real-world data is necessary to resolve the complexities involved in predicting customer responses to rate design changes and in understanding the impact on a utility's finances.

During the expert witness hearing, Public Staff witness Junis testified that instead of the pilot program proposed by Aqua NC, the Public Staff would prefer that statewide inclining block rates, with a CAM, be considered in the next rate case. He later modified his statement regarding statewide inclining block rates by saying that "I think we would consider slightly modified inclining block rates for the different rate entities." Witness Junis also noted that any rate design implemented for Aqua NC would likely be "tweaked" as actual experience is obtained. Witness Junis stated that Aqua NC should be required to maintain consumption billing data in 1,000 gallons blocks for the Public Staff and Aqua NC to properly evaluate and structure an inclining block rate structure. Witness Junis also pointed out the disadvantages of an inclining block rate structure stating that such a rate structure can penalize large families which have a higher level of non-discretionary usage and that depending on the design of the blocks, they may pay significantly more. He noted there can also be situations where unrecognized water leaks develop which can result in a "giant" bill. Although not presented in his prefiled testimony, witness Junis' testimony concerning the implementation of statewide inclining block rates for Aqua NC is consistent with the comments filed by the Public Staff in Docket No. W-100, Sub 59.

The Commission agrees with Aqua NC witness Thill that pilot programs are by their very nature limited; that the pilot is rightfully intended to affect Aqua NC's discretionary water users with the greatest capacity for conservation that are more prevalent in the Company's high-usage water systems; that Aqua NC's proposed pilot covers ten percent of Aqua NC Water; that this level of coverage, particularly in areas of high consumption, can reasonably be expected to provide useful data and valuable customer behavior information which can be used to refine the rate structure and apply it to the Company's larger customer population in future cases; that the proposed revenue reconciliation process acts as a safeguard both for Aqua NC and its customers; and that the allegations of discrimination and prejudice raised by the Public Staff would preclude implementation of any pilot programs, since pilots, by définition, generally apply to a subset of the customer base.

Although the Commission declines to accept the implementation of the Company's proposed pilot program in the Fairways Water Rate Division, the Commission concludes that the Company's proposed pilot program for a portion of the Aqua NC Water Rate Division will better allow Aqua NC to analyze the results this pilot will have on a smaller scale before designing and applying any one or more final rate designs to the larger population of the Company's customers. The Commission concludes this analysis on a smaller scale is particularly important because there are many variabilities in an inclining block rate structure, from the number and size of the blocks, to the various step points, and the magnitude of the unit price difference between blocks. Further, the Commission concludes that an analysis of the impact these variables have on the effectiveness of the rate structure in promoting water efficiency and conservation should include both an evaluation of the municipal and town water and sewer systems operating in the State that currently utilize inclining block rate structures as well as actual customer reaction and changes in consumption observed through the implementation of Aqua NC's pilot program.

Moreover, there are not presently any tiered rate structures approved for the North Carolina water and sewer utilities regulated by the Commission. Implementation of tiered inclining block rate structures would be a significant change in rate design for the regulated water and sewer utilities. It is reasonable and appropriate to implement a pilot program in a portion of Aqua NC's

Water Rate Division to allow Aqua NC, the Public Staff, and the Commission to analyze the results on a smaller scale before designing and applying any one or more final rate designs to the larger population of Aqua NC. The application of a pilot program in a portion of Aqua NC's Water Rate Division should provide the Company, the Public Staff, and the Commission an opportunity to explore the effects of a tiered inclining block rate structure on a variety of customer types in several geographical areas in the State; to make comparisons of actual pilot program results to data pertaining to nonregulated entities (towns, municipalities, etc.) that utilize inclining block rates; to evaluate the feasibility of utilizing inclining block rates rather than Aqua NC's current single-tier rate design structure compared to the resulting benefits in water efficiency and conservation; and to review Aqua NC's reports of the monthly consumption data of accounts by blocks of 1,000 gallons to ensure that all required information is captured prior to possible full or permanent implementation of inclining block rates in some or all of Aqua NC's service areas.

Furthermore, the application of a pilot program in a portion of Aqua NC's Water Rate Division should provide the Company, the Public Staff, and the Commission the necessary data to compare whether other rate design proposals, such as a rate design consisting of 30%/70% base to usage charge with a CAM, may achieve similar water conservation objectives while being simpler to administer.

The Commission observes that there are approximately 6,000 residential customers on the Bayleaf Master water system and there are fewer than 800 residential sewer customers. The Bayleaf Master water system customer base is not a uniform group of high-consumption households but rather includes some diversity with respect to water usage. Bayleaf is a water system with a history of marginally adequate well water capacity during extended periods of high demand that typically occur during hot, dry weather which historically has resulted in heavy lawn and shrub irrigation. Bayleaf water customer Becky Daniel testified at both the public hearing held during Aqua NC's last rate case (Sub 497) and the present proceeding. Witness Daniel testified in support of Aqua NC's proposed pilot program for the Bayleaf Master water system.

Although there is opportunity for both conservation and operational relief with implementation of a pilot program in The Cape service area, the Commission concludes that it is not appropriate to implement such a program in this proceeding because the metered water rates for the Fairways Water Rate Division are significantly lower in comparison to Aqua NC's Uniform Water and Brookwood Water Rate Divisions and thus will not provide meaningful results to extrapolate across the Company's full customer base in future rate design planning. Further, of the approximately 4,251 customers to be included in The Cape pilot program, the majority of the customers, 2,876 customers, are both water and sewer customers and 1,375 are water-only customers. Consequently, the Commission concludes that the approval of metered sewer rates for The Cape service area will send a conservation signal to high volume water users through the metered sewer charge. Implementing both metered sewer rates and an increasing block structure would complicate the evaluation analysis of the pilot program and the revenue reconciliation process.

The Commission acknowledges that there are necessarily winners and losers in any change to Aqua NC's pricing structure. The lower volume water users will experience an overall reduction in their average monthly bills and the high-volume users will experience an overall increase in their average bills if they do not change their usage patterns. This is consistent with the concept that, although most of the utility's expenses are fixed, it is the peak demand requirement of a system's high-volume users that fosters the greatest incremental cost. The focus of Aqua NC's pilot program is to provide rate relief for customers whose usage falls within the lower blocks and inducing conservation in those whose usage extends to the higher block levels.

The Commission determines that revenue sufficiency and stability is addressed in two ways in the pilot program. First, the consumption estimates Aqua NC used to determine pricing bands in the pilot areas have been reduced to reflect demonstrated trends in price elasticity. Price elasticity measures the responsiveness of consumption to price changes. The Company incorporated an elasticity of -0.3 in its consumption projections. That is, a 10% increase in consumer cost is assumed to drive a 3% decline in consumption. The Company's second measure to ensure revenue sufficiency and stability is the implementation of a revenue reconciliation process specific to the pilot areas. This proposed revenue reconciliation is specific to, and integral to, Aqua NC's willingness to implement the pilot program.[1] Considering the many variables that influence water demand and that this pilot program intentionally means to increase the variability of that demand, as a general matter of fairness there must be a settlement process to ensure that neither the pilot customer group (as a whole) nor the Company is unduly harmed or enriched by this program. The intent of the revenue reconciliation is that the Company should receive its full authorized revenue requirement, no more and no less.

The Commission concludes that for purposes of implementing a pilot program in a portion of Aqua NC's Water Rate Division, a revenue reconciliation process applicable only to the pilot group is in the public interest. The Commission acknowledges that N.C.G.S. § 62-133.12A allows the Commission to "adopt, implement, modify, or eliminate a rate adjustment mechanism for one or more of the company's rate schedules to track and true-up variations in average per customer usage from levels approved in the general rate case proceeding" upon a finding that such mechanism is appropriate to track and true-up variations in average per customer usage and is in the public interest. The Commission concludes that it is reasonable and appropriate that a revenue reconciliation process as set forth by the Company be integral to the pilot program; however, such revenue reconciliation process in this docket for this specific purpose is not intended to establish the process by which any future revenue reconciliation for Aqua NC or other regulated utilities related to actual consumption variances from Commission-approved levels in general rate case proceedings as allowed by N.C.G.S. § 62-133.12A will be calculated.

In regard to the Public Staff's opposition to Aqua NC's proposed pilot programs, the Commission concludes that during the course of its investigation in this proceeding, the Public Staff had adequate time to prepare and propose alternatives to Aqua NC's proposed pilot program, but, instead, simply proposed a more volumetric water and sewer rate design without the benefit

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[1] Aqua NC witness Thill testified that if a consumption decline is not factored into the rate design process, any success of the program as proven by reduced consumption will necessarily be absorbed by the utility in the form of insufficient revenue and reduced rate of return on common equity. According to the Company, incorporating a consumption decline, or repression, in the calculation ensures that the utility is not working against its own interest in further funding the public policy initiative of conservation.

of a CAM or a revenue reconciliation process to afford a degree of protection to the Company's earnings and authorized revenue stream.

Accordingly, for the reasons set forth above, the Commission concludes that the Company's proposed Conservation Pilot Program in a portion of the Aqua NC Rate Division and the integral revenue reconciliation procedure should be approved and adopted for purposes of setting water rates in this proceeding. For the reasons set forth herein, the Commission declines to adopt the Company's proposed pilot program in The Cape service area, which is part of the Fairways Water Rate Division. Further, the Commission finds and concludes that Aqua NC should implement the pilot program for a period of time that allows the Company to accumulate sufficient information to analyze the results of the pilot and to apply such results to designing proposed future rate structures. Consequently, the Commission determines that Aqua NC's pilot program should include at least two summer irrigation seasons but should conclude within three years of the implementation date or the effective date of new base rates in a general rate case application, whichever is earlier.

With respect to reporting requirements related to the pilot program, the Commission concludes that Aqua NC and the Public Staff should work together collaboratively (1) to design a quarterly report format to file with Commission to inform the Commission regarding the ongoing impact of the pilot program (i.e., the change in consumption, customers, and revenues compared to historical levels) and any other matters pertinent to the evaluation or continued implementation of the pilot program and (2) to file a semiannual report to inform the Commission regarding the detailed calculation of the revenue reconciliation process indicating the amount to date of any surcharge or surcredit to customers. In regard to whether a carrying cost should be applied to the annual surcharge or sur-credit to customers, that matter will be determined by further order of the Commission in conjunction with the parties filing of the first proposed annual revenue reconciliation adjustment. Further, the quarterly report format should, at a minimum, include monthly historical and current consumption by blocks of 1,000 gallons and the corresponding number of bills and revenues for each customer group (i.e., water only customer, water and metered sewer customer, water and flat-rate sewer customer, and water and sewer with separate irrigation meter, etc.) and should be filed within 30 days of the end of each calendar quarter. Such quarterly report may be revised as needed in future filings as determined by Aqua NC, the Public Staff, and the Commission. The semiannual reconciliation report should be filed within 30 days of the end of the reporting period. In addition, the annual revenue reconciliation request and the supporting calculation and data for an annual adjustment should be filed with the Commission at least 45 days prior to the annual adjustment effective date.

Finally, for purposes of the pilot, the Commission concludes that the approximately 800 sewer customers on the Bayleaf Master System should remain a monthly flat rate sewer customers for the implementation of the pilot program due to the Company's proposed reconciliation process being a required integral component of any Commission-approved pilot program. The Commission determines that the complications the conversion from a monthly flat rate sewer to metered sewer rates will create for the small number of sewer customers on the Bayleaf Master System should be avoided in order to allow Aqua NC, the Public Staff, and the Commission to obtain a more reasonably accurate analysis of the approved pilot program.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 45–62

Utility Plant in Service and Plant Unitization

The evidence supporting these findings of fact is contained in the joint testimony of Public Staff witnesses Henry and Junis, in the rebuttal testimony of Company witness Thill, and the record in this proceeding.

Summary of Public Staff Testimony

Public Staff witnesses Henry and Junis testify that they conducted an investigation of the Company's plant additions to rate base by reviewing Aqua NC's utility plant in service records and supporting documentation. They state that the Public Staff typically confines its investigation to the period from the update period in the prior rate case through the update period in the current rate case. However, in order to investigate the Company's novel request for aggregated deferral accounting treatment made in its application in the present docket, witnesses Henry and Junis testify they investigated the Company's plant additions dating back to 2015. Tr. vol. 4, 260-61.

Witnesses Henry and Junis describe the term "plant additions," which are capital assets, typically including additions, improvements, and replacements, booked to plant accounts with associate depreciation rates. They note that a single project can consist of more than one addition to the general ledger plant accounts. They also include in their prefiled testimony Company witness Thill's definitions of various terminology the Company uses in its asset management system. *Id.* at 261. According to witness Thill, "completion date" means "a general indication that an asset is 'useful' but it is strictly informational as no system action derives from this data. Aqua NC personnel may use this field as a tickler to indicate substantial completion and to alert accounting personnel to monitor final bill processing and subsequent unitization." The term "in-service date" means "the date the asset is placed in-service and being 'used' for the benefit of customers. This date drives the retirement calendar (except for 'blankets' . . .) and terminates any AFUDC calculation." *Id.* at 261-62 Finally, witness Thill defines "posting or unitization date" as follows:

> This is when the asset is removed from CWIP and added to UPIS, and begins depreciating. Unitization occurs after determination that an asset is both complete (useful) and in-service (used). In that Aqua has been directed by the Public Staff that projects should close only a single time, unitization is also subject to timing of vendor invoicing – that is, unitization occurs only after all vendor invoices have been processed which may be months after either (or both of) the completion or in-service dates.

Id. at 262.

Witness Thill subsequently clarifies for witnesses Henry and Junis that the in-service date "drives auto-retirements (where applicable) and stops AFUDC" and that unitization "starts depreciation; must be complete and in-service." *Id.* at 261-62. Witnesses Henry and Junis contend that ideally, the in-service date will occur in the same month as the unitization date. *Id.*

Witnesses Henry and Junis note in their testimony that the issue of the Company's UPIS practices and procedures was addressed in the Docket No. W-218, Sub 274 rate case, and that the Commission had accepted the provisions of the Sub 274 Joint Stipulation and ordered the Company, among other things, to "adopt a consistent, accurate, and complete accounting system for its detailed plant records that maintains its plant records in compliance with the Uniform System of Accounts," and to "review its procedures for determining when projects are completed and should be closed and file its recommended changes to its procedures within 90 days . . . ." *Id,* at 263 Witnesses Henry and Junis further note that, in its First Status Report filed in response to the Commission's Sub 274 Order, the Company stated that the Company's Accounting Department allowed 30 to 60 days after the in-service date for projects to be booked. *Id.* at 263-64. According to witnesses Henry and Junis, this approach would be acceptable to the Public Staff if utilized consistently and for an overwhelming majority of its CWIP projects. Relying on the Company's description of its accounting practice, the Public Staff states it did not review the in-service and unitization dates for projects included in rate base in the Company's Sub 497 rate case in great enough detail to recognize a number of instances in which more than 30 to 60 days elapsed between when a project was placed in-service and when it was unitized. *Id.* at 266. These projects, totaling approximately $4.7 million, were identified by the Public Staff in its investigation of the Company's novel request for aggregate deferral accounting treatment. *Id.* at 260-61. Witnesses Henry and Junis state that while some projects were booked just over 60 days from the in-service date, due to the timing of those events, the in-service date and the unitization date occurred in different years. The Public Staff does not recommend an adjustment related to the approximately $4.7 million in projects it identified for which unitization occurred more than 60 days after the in-service date. However, the Public Staff requests that the Commission take the matter into consideration in its decision. *Id.* at 266.

While the Public Staff identifies a number of projects that were not unitized within 60 days of the in-service date, witnesses Junis and Henry note in their testimony that they also identified instances in which the Company unitized plant additions within the same month that they were placed in-service. Witnesses Henry and Junis point out that this was inconsistent with explanations provided by the Company as recently as June 2019 that it took 30 to 60 days to complete the accounting process to book capital projects. *Id.* at 267. Witness Junis further notes on cross-examination that unitizing assets more quickly than in 30 to 60 days benefitted the Company in some instances, such as where the Company could recover the costs of a project in a WSIC/SSIC proceeding. *Id.* at 328. As an example, witnesses Henry and Junis state that the Company had not updated its November 1, 2019 WSIC/SSIC application[1] to account for ($16,354) in plant adjustments and therefore, has been recovering the incremental depreciation expense and capital costs associated with that amount through mechanism surcharges since January 1, 2020. Witnesses Henry and Junis note that they would recommend that this excess recovery between January 1, 2020, and the date of the rate case order be refunded as part of the annual review and EMF at the end of 2020. *Id.* at 268.

Witnesses Junis and Henry state that based on their investigation that many of the unitizations they identified in the first and third quarters of each year occurred more than 60 days after the in-service date. They note that the first and third quarters are also the second halves of

[1] See Docket No. W-218, Sub 497A.

the WSIC/SSIC semiannual adjustment periods, or during the post-test year period of rate cases. Witnesses Henry and Junis assert that the delay in the start of depreciation that occurred as a result of the Company's UPIS accounting practices resulted in the reduction of accumulated depreciation and additional return from a corresponding increase in rate base. The witnesses maintain that this delay in the start of depreciation along with the Company's unitization of plant costs close to the point when rate recovery occurs benefits the Company financially. *Id.* at 267.

Witness Henry explains that Aqua NC "uses a half year convention, so no matter what point in time that that asset is booked, the Company captures a half year of depreciation for that particular asset in the year in which it was placed in service." *Id.* at 326. Witnesses Henry and Junis explain that delays between the in-service date and the unitization of an asset have an especially significant impact when the in-service date occurs in one year and the unitization date occurs in a subsequent year. Witness Henry further explains regarding this scenario, "you are missing out on a full year of accumulated depreciation if you unitize in the latter year versus the . . . former year when [the asset] went into service." *Id.* at 324. On examination by Commissioner Duffley, witness Junis asserts that unitization in the year after the in-service date functions as a deferral that essentially shifts the depreciation life of the asset a year into the future. As a result, witness Junis contends that the Company avoids losing rate recovery for a year's worth of depreciation expense due to lag and the reduction to rate base from the associated accumulated depreciation. *Id.* at 350-51.

With respect to the present rate case, witnesses Henry and Junis recommend several in-service date and cost adjustments to UPIS and accumulated depreciation. As part of the Public Staff's review of the Company's Application for Approval of Water and Sewer System Improvement Charge Rate Adjustments Pursuant to N.C.G.S. § 62-133.12 filed on May 1, 2019, in Docket No. W-218, Sub 497A, the Public Staff recommended removal of two Aqua NC Water filtration projects totaling $648,434 that were not in service and used and useful during the applicable WSIC/SSIC period. The Public Staff also recommended that the Commission approve adjustments related to 13 projects totaling approximately $1.7 million that were placed in service in the third and fourth quarters of 2018 but were not unitized until the first quarter of 2019. These adjustments totaled $50,202, or an additional nine months' worth of accumulated depreciation. Witnesses Henry and Junis recommend that these regulatory accounting adjustments, which were not accounted for in the Company's rate case application, be approved and that Aqua NC be required to include them in all future rate cases until the assets are retired. *Id.* at 269-70.

The second set of adjustments for which witnesses Henry and Junis recommend in-service date changes and cost adjustments to UPIS and accumulated depreciation related to capital expenditures unitized by the Company in the post-test year period in the present rate case of October 2019 through March 2020. Public Staff witnesses Henry and Junis adjusted the unitization dates for 44 plant additions totaling approximately $1.4 million. The adjustments changed the unitization date to the in-service date specified by Aqua NC unless there was information showing that the asset was not actually placed in service on that date, and all of the adjustments resulted in the accumulation of additional depreciation in the present or future rate cases. Witness Junis explains on cross-examination that for assets that were placed in service in 2019, but unitization and the beginning of depreciation did not occur until 2020, a year of accumulated depreciation is lost. *Id.* at 331. Witness Henry testifies that, for ratemaking purposes, the Public Staff included a full year of depreciation expense and of accumulated depreciation in the present rate case to establish a representative level of depreciation and accumulated depreciation that the Company would incur going forward. Witness Henry contends that adjustments would need to be made by the Public Staff in the Company's next general rate case to correct the Company's books for the errors in unitization dates identified by the Public Staff in this proceeding. *Id.* at 332. In addition to the adjustments to in-service dates, witnesses Henry and Junis recommend four adjustments to reduce plant for excessive accrual of AFUDC. *Id.* at 271, 330.

In addition to their recommended adjustments, witnesses Henry and Junis summarize their position regarding the issue of unitization as follows, including a recommendation for the Commission to address the issue:

> The Public Staff believes that unitization should occur within 30 to 60 days of the in-service date, and that depreciation should always begin as of the in-service date. The Public Staff understands there may be exceptions to when the project unitization occurs, but depreciation should always begin when an asset is placed in service, without exception. The Public Staff strongly believes the procedure should be that depreciation begins and accrual of allowance for funds used during construction, AFUDC, ends on the in-service date. To address this issue, the Public Staff recommends that the Commission order the Company to review its procedures for determining when projects are completed, in service, and booked, and file the Company's findings on its internal practices, and any plans to change the procedures, within 90 days of the Commission's final order in this proceeding. Tr. vol. 4, 308–9.

On cross-examination, witness Junis revises this recommendation based on new information that the Company's PowerPlan asset management system includes a function that enables the Company to designate assets as "completed but not classified."[1] Witness Junis states that this newly identified function stops the accrual of AFUDC and begins depreciation at a general depreciation rate of the related plant. Witness Junis explains that, after an asset is booked at the general depreciation rate, costs in sub-accounts associated with the various components of the asset would "continue to be accounted for during a designated period of time or until it is believed that all the costs have been captured." He further explains that at the end of this period, the costs that have been collected and the accumulated depreciation that has accrued since the asset's in-service date is booked to the appropriate sub-accounts. *Id.* at 319–21. Witness Junis states that it is his understanding that this function is utilized by various other Commission-regulated utilities in the state including Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Piedmont Natural Gas Company, Inc. Witness Junis recommends that the Commission order Aqua NC to also utilize this function. *Id.*

[1] Account 106, Completed Construction Not Classified - At the end of the year or such other date as a balance sheet may be required by the Commission, this account shall include the total of the balances of construction projects for service company property which has been completed and placed in service but which work orders have not been classified for transfer to the detailed utility plant accounts. Uniform System of Accounts for Class A Water Utilities (1996).

Witness Henry admits on cross-examination that the practice utilized by Aqua NC has been to begin depreciation as of the unitization date. He also agrees that it is a true and "fair statement" that the only time the situation arises where the Public Staff would contest the unitization dates and the accrual of depreciation is when the plant was placed in service before the end of one calendar year, but unitization was not completed until sometime after the first day of the subsequent calendar year. *Id.* at 328.

In response to a question from Commissioner Clodfelter regarding Aqua NC's AFUDC calculations, witness Henry states that the Public Staff, with the exception of adjustments to in-service dates for certain "long-lived" projects which the Public Staff made in this case, the Public Staff is generally satisfied with Aqua NC's methodology for calculating and accruing AFUDC. Tr. vol. 4, 342–43.

Summary of Company Rebuttal Testimony

Aqua NC witness Thill testifies on rebuttal that Aqua NC disagrees with the Public Staff's conclusion that the Company's UPIS practices are inconsistent and can result in windfalls to the Company to the detriment of ratepayers. Witness Thill testifies that Aqua NC has systems and processes in place to track, document, and verify its UPIS. Witness Thill states that these systems and processes consist of annual reviews of internal controls performed because Aqua NC's parent company, Essential Utilities, is subject to the Sarbanes-Oxley process, Aqua NC's finance department's quarterly reviews of capital project reports and meetings with operations and engineering staff regarding the status of CWIP, and Essential Utilities' internal audit group's three-year rotational review of state operations. He acknowledges that "real work events" such as vacations, sick time, field staff experience levels, and communication between those field staff and accounting staff impacts the Company's UPIS processes. Witness Thill discusses some of the factors that complicate the Company's UPIS procedures, including the large volume of projects the Company processes each year, and the need to close projects for individual systems, but he contends that, overall, the Company has, in its UPIS processes, balanced the interests of its various stakeholders, including shareholders, employees, bondholders, and customers. Tr. vol. 6, 41-45.

Witness Thill maintains that the Company's use of the mid-year depreciation convention minimizes the impact of the unitization date during the same calendar year. He acknowledges, however, that when an asset "crosses years" depreciation is lost. For example, when an asset that was placed in service in 2019 is unitized in 2020, one year's worth of depreciation is lost. *Id.* at 44-45.

Regarding the Public Staff's concerns about delays in the unitization of certain projects, witness Thill asserts that factors outside the control of the Company such as vendors and regulatory agencies can contribute to such delays. Responding specifically to Public Staff witnesses Henry and Junis' Exhibit 1 to their testimony showing discrepancies between in-service dates that occurred in 2017 and unitization dates that occurred in 2018 for a number of Aqua NC plant additions, witness Thill notes that final invoice payments for some projects having in-service dates in October 2017 were not paid until December of that year and stated that projects "***cannot*** close until all costs are in." *Id.* at 47. Witness Thill maintains that "information [regarding final payments] is often not known for some window of time after payments are made due to the necessary coordination between internal departments and external vendors . . . ." *Id.* at 47-48.

Regarding Public Staff witnesses Henry and Junis' contention that "the Company benefits financially from unitizing plant costs as close to rate recovery as possible," witness Thill contends that a more accurate statement is that "the Company is harmed less by lag when it unitizes plant costs as close to rate recovery as possible." He acknowledges that, as identified by the Public Staff, "unitizations occur at a higher frequency in months that cut off the two semiannual WSIC/SSIC filing periods," and suggests that this should not be considered "surprising or alarming" because part of the purpose of the WSIC/SSIC mechanism is to lessen the effects of regulatory lag. *Id.* at 48.

Witness Thill acknowledges that the Company had not updated its November 1, 2019 WSIC/SSIC application to account for ($16,354) in plant adjustments as noted by Public Staff witnesses Henry and Junis. However, witness Thill asserts that the Company included and that the Public Staff was aware of all but $1,829 of the adjustments at issue. Witness Thill further asserts that the failure to include that amount was the result of an inadvertent mistake and not the product of a variance of the Company's accounting procedures or evidence that a review of those procedures is necessary as the Public Staff suggested. *Id.* at 50. Witness Thill testifies that Aqua NC did not challenge the Public Staff's adjustments to the in-service dates for 13 projects totaling approximately $1.7 million that were placed in service in the third and fourth quarters of 2018 but were not unitized until the first quarter of 2019. These adjustments are shown in Exhibit 4 to the joint testimony of witnesses Henry and Junis. *Id.* at 52-53.

Regarding the Public Staff's recommended adjustments to the unitization dates for 44 plant additions related to capital expenditures unitized by the Company in the post-test year period, witness Thill maintains that the Public Staff's analysis "does not take into account the reality of the every-day operations of the utility." Witness Thill states that in any given month, the Company is closing as much as $13 million in rate base. Excluding the auto-unitizing "blanket"[1] projects, the Company manually unitized an average of 133 line-items per month in 2015-2020, and as many as 749 in a single month. Witness Thill explains that each of these line-items can be as simple as a single invoice or as complex as hundreds of lines of activity including vendor payments, internal payroll capitalizations, inventory assignments, overhead allocations and AFUDC assessments. Witness Thill notes that the Public Staff's analysis used to support its recommendation "moved the unitization date in advance of the final vendor payment for ten of the 44 line-items, *a practice unavailable to the Company as Staff has previously required that projects close a single time once all costs are final.*" *Id.* at 54. Witness Thill contends that the projects for which the Public Staff adjusted the unitization dates made up a small fraction of the asset additions recorded in the first quarter of 2020 and that, in adjusting the unitization dates, the

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[1] "Blanket" funding projects represent a specific category of asset additions with particular characteristics within the Company's PowerPlan asset subledger. These projects are typically routine replacements, often emergency services or similar expenditures that require no engineering or long-term coordination of resources. These assets are not assigned (and Aqua NC personnel have no ability to assign) completion or in-service dates as they are immediately unitized and placed in-service in the month the expenditure is incurred. This is a standard feature of the PowerPlan asset subledger, a software program designed for the utility industry. Because these purchases unitize individually each month for each asset class and each system, Aqua NC's asset listing is overwhelmingly comprised of blanket purchases.

Public Staff disregarded its "past policy of a 30-60 day closing period" and failed to take a "holistic" view of the Company's unitization practices.

Witness Thill states that projects are a compilation of the efforts of specialists: engineers, operators, and compliance professionals. He further states that the Company does not employ an overlay of professional project managers but rather relies on the individual specialists to successfully execute within their silos of expertise, as well as in concert with each other. Witness Thill explains that the unitization process is coordinated by the Company's property accountant. He describes that individual as a highly skilled and experienced accountant, and though neither a project manager nor a field expert, he states that her role has elements of each discipline. Witness Thill contends that it is particularly the project management element that instills complication and real-world challenges in the unitization process as she coordinates the administrative "punch list" of open items across the various disciplines, integrated with the accounting requirements to ensure that vendor payments occur only when properly approved and substantiated.

According to witness Thill, the North Carolina requirement for system level assignment of assets is unique. He states that it was his understanding that no other state in which Essential Utilities operates requires assets within the same consolidated rate division to be accounted for at the individual water system level. Witness Thill provides perspective to the diffuse nature of Aqua NC's operations and resultant accounting challenges by stating that there are 735 water systems and 64 sewer systems in Aqua NC. He notes that these North Carolina systems comprise nearly 50% of the systems in all of Essential Utilities America but serve less than 10% of all its customers. Witness Thill contends that the system-level of detail takes away one of the benefits of consolidation and exacerbates the added layer of work in tracking the thousands of projects Aqua NC's employees work on every year.

Witness Thill states that the Company has adapted to the requirement to maintain system-level asset information. However, he notes that real work events impact the process. Employee vacations and sick time, vendor changes, delays, and varying levels of field staff experience are just a few examples of factors that impact the process. He also notes that, building on earlier discussion regarding project management, communication between the field staff and accounting staff is key here. He explains that in maintaining system-level asset information, due to the way in which individual projects are closed, that communication also impacts the timing of closing projects.

Witness Thill testifies that the Public Staff's concern is that the Company allegedly intentionally unitizes assets inconsistently. He notes that according to the Public Staff, the unitization occurs too quickly in some cases, and not soon enough in others. He agrees that when an asset unitization is delayed, even where necessary or unavoidable, it can end up in the wrong year. He states that the Public Staff's concern follows that this impacts the starting period for depreciation and that can have an impact on rate base and therefore rates.

Witness Thill concedes the project-specific reductions to plant recommended by the Public Staff for excessive accrual of AFUDC related to the "Bridgepoint #8 Instl AquaGuard" and the "Instl AquaGuard Coachmans Trl #3." Witness Thill disagrees with witnesses Henry and Junis' recommendation that the entire AFUDC amount of $12,526.25 be disallowed for "Field Tablets –

2019." In support of his position he states that the Public Staff's determination that the procurement of the field tablets was not construction in progress "ignores the very nature of AFUDC, which is to recognize the capital cost of financing such a purchase." Witness Thill also disagrees with witnesses Henry and Junis' recommendation that only the portion of the total cost of the "RC New Generator Beachwood 02-196" incurred in 2018 in the amount of $10,043.95 be included in plant. In support of his position, witness Thill notes that approximately $20,000 was spent on the project in 2011 and 2012, and that the project did not restart until 2018, due to problems obtaining approval from a local official. He asserts that the usefulness of the asset should control whether the associated costs are recoverable, not the age of the costs. *Id.* at 58-59.

Witness Thill testifies that the scope of the issues related to UPIS raised by the Public Staff was relatively small, and notes that the impact of the Public Staff's reassignment of unitization dates for $1.6 million of plant additions "yielded a $4,400 reduction in the revenue requirement in this case." In his prefiled rebuttal testimony, in response to the witnesses Henry and Junis' recommendation in their prefiled testimony that the Company review and file a report on its UPIS procedures, witness Thill testifies that, while the Company contends the processes and procedures currently in place related to UPIS are appropriate, he states "there is always room for improvement" and notes that Aqua NC was not opposed to reviewing its UPIS procedures but did not think a report was necessary. *Id.* at 60-61.

During the expert witness, witness Thill provides an addendum to the position stated in his prefiled rebuttal testimony. Specifically, witness Thill states as follows:

> [I]f the Commission is so inclined and in lieu of reaching a decision on the merits based on the evidence of the record in this case, the Commission adopt the recommendation of the Public Staff witnesses Henry and Junis, quote "To order the Company to review its procedures for determining when projects are completed, in service, and booked, and file the Company's findings of its internal practices [and] any plans to change the procedures within 90 days of the Commission's Final Order in this proceeding," closed quote.
>
> This would allow Aqua and the Public Staff ample time to fully explore and address the UPIS issues prior to the Company's next rate case and either come to a consensus settlement or engage in further litigation regarding these issues in that case.

Id. at 78-79.

During its case on rebuttal, Aqua NC requested and was granted, over the objections of the Public Staff, permission to conduct supplemental rebuttal examination of witness Thill on the topic of Aqua NC's PowerPlan asset management system which was addressed by Public Staff witness Junis on cross examination. Witness Thill testifies on supplemental rebuttal examination that Aqua NC began using the PowerPlan asset management software in 2009 or 2010. Witness Thill testifies that the Company's decision to utilize PowerPlan was associated with its acquisition of a number of disparate systems using a variety of different accounting systems and the Commission's directives that the Company take steps to better manage its accounting processes. Witness Thill testifies that he did not think the UPIS issues raised by the Public Staff in the present rate case were the same issues that had prompted Aqua NC to begin using PowerPlan. *Id.* at 93-101.

When asked by Commissioner Clodfelter whether the version of PowerPlan used by Aqua NC contains the "completed but not yet categorized" module or functionality described by witness Junis on cross-examination which stops the accrual of AFUDC and begins depreciation at a general depreciation rate of the related plant, witness Thill testifies "it does." Witness Thill clarifies that it was his understanding that Aqua NC's version of PowerPlan had contained that module or functionality since Aqua NC began using the software and that it was his understanding that other Essential Utilities subsidiaries use the module or functionality. Finally, witness Thill states that, "generally speaking," witness Junis correctly described the manner in which the module or functionality operates with respect to costs that are captured after an asset has been placed in service. Tr. vol. 7, 36. However, witness Thill later notes that knowledgeable Aqua NC staff had concerns about the viability of the "completed but not yet categorized" functionality in Aqua North Carolina's particular case. *Id.* at 47-48.

In response to a question from Commissioner McKissick regarding when depreciation should begin on the in-service date or on the unitization date witness Thill first provides the Uniform System of Accounts description of CWIP which he states is, "Work orders shall be cleared from this account as soon as practicable after completion of the job." Witness Thill further states regarding the description, "And so it's not even a question in here about when it's in service. It talks about after completion. And it talks about practicable, because this is not as easy as it seems." *Id.* at 44.

Witness Thill describes what he thinks should be the "overriding beginning principle" governing UPIS practices and procedures as follows:

> Things should move from [CWIP] into depreciable plant in service when practicable, not on a particular system date, but when practicable, that flows into the system that was developed at the time which was to say that it's going to take sometimes 30 to 60 days for us to do the complete unitization, to move this from CWIP into depreciable property. So sometimes it's going to take some time.

Witness Thill did not provide an explanation for the instances identified by witnesses Henry and Junis in which it took the Company in excess of 30 to 60 days to complete unitization. Witness Thill contends that the Company's ability to unitize some projects within the same month as the in-service date was not evidence that the Company always has the capability to do so. *Id.* at 46.

Returning to Commissioner McKissick's original question – when should depreciation begin – witness Thill ultimately answered "I'm not sure, because there may be costs associated with modifying the system in order to be able to change when that happens." He further testified, "I think the Public Staff has raised an issue which is quite frankly valid . . . . I think it's important that we all evaluate it. As I mentioned, we started looking at that a year ago and we made one modification. I don't think it's probably enough and I think it needs to continue to develop much as this entire argument has." *Id.* at 49-50.

Witness Thill agrees with Commissioner McKissick that the establishment of a bright line standard for when depreciation begins would be beneficial to all parties involved, but he notes that it would be important for the Company to conduct a review of the issue and understand the implications of any standard that is implemented. *Id.* at 51.

Discussion and Conclusions

The Commission acknowledges that the issue of the Company's UPIS accounting practices and procedures was addressed by the Commission in the Company's rate case in 2009 in Docket No. W-218, Sub 274 after the Public Staff determined that the Company's plant records were inadequate following Aqua NC's acquisition of several disparate water and wastewater utilities. In the Sub 274 proceeding, the Public Staff and Aqua NC stipulated that the Company would take various steps to remedy this issue, including that the Company would "review its procedures for determining when projects are completed and should be closed and file its recommended changes to its procedures within 90 days of the issuance date of [the Sub 274] Order."

In its first report filed in response to the Sub 274 Order, Aqua NC stated that the Company's Accounting Department allowed 30 to 60 days after the in-service date for projects to be booked. However, as evidenced by the testimony and exhibits of Public Staff witnesses Henry and Junis in this proceeding, the Company has failed to consistently book or unitize projects within that timeframe. According to witnesses Henry and Junis, the Company's unitization of some projects more than 60 days after they are placed in service has resulted in the Company continuing, on occasion, to accrue AFUDC after the in-service date and postponing the start of depreciation. Witnesses Henry and Junis explain that this delay in unitization of projects can lead to a decrease in accumulated depreciation and a corresponding increase in rate base which can be financially beneficial to the Company and detrimental to ratepayers. The impact of delays in unitization is magnified when, as witnesses Henry and Junis demonstrated, unitization does not occur until the year after an asset is placed in service.

While Aqua NC witness Thill testifies that the number of projects identified by the Public Staff as having unitization issues was relatively small in comparison to all of its plant additions including routine replacements, WSIC/SSIC projects, and other CWIP projects, the Commission observes that inconsistency in the Company's UPIS accounting practices and procedures is a longstanding issue that may have a detrimental effect on customers, although the Commission acknowledges that the controversy as to when depreciation should begin is a relatively new development in this rate case.

In this proceeding Aqua NC requests that the Commission allow the unitization date to be the date in which depreciation begins; whereas the Public Staff maintains that the in-service date is the appropriate date. Witnesses Henry and Junis testify that ideally, the in-service date will occur in the same month as the unitization date. Although not presented in their joint prefiled testimony, at the expert witness hearing witness Junis testifies that he recently became aware that the PowerPlan asset management system contains a "completed construction not classified" or "Account 106" function that stops the accrual of AFUDC and begins depreciation when the asset is placed in service, while allowing for components of the asset to "continue to be accounted for during a designated period of time or until it is believed that all the costs have been captured." On cross-examination from the Commission, witness Thill states that it was his understanding that Aqua NC's version of PowerPlan had contained that module or functionality since Aqua NC began using the software and that other Essential Utilities subsidiaries use the module or functionality. However, witness Thill notes that knowledgeable Aqua NC staff had concerns about the viability of the "completed but not yet categorized" functionality in Aqua NC's particular case.

Based upon the record evidence in this proceeding, the Commission acknowledges that Aqua NC has operated under the PowerPlan accounting system since August 27, 2010, with unitization and recording of plant additions on a system-specific basis having been initiated in the second calendar quarter of 2010. In particular, in its Quarterly Status Reports filed in Docket No. W-218, Sub 274, Aqua NC informed the Commission that "[o]n a monthly basis the Accounting Department sends the Regional Managers a CWIP report for review, requesting that the Managers notify Accounting of projects that are complete and in service. Accounting allows 30 to 60 days for any trailing costs to be charged to these in-service activity numbers before closing the asset." Since that time, the Commission notes that Aqua NC has had three general rate cases (Subs 319, 363, and 497) prior to the Company's current Sub 526 rate case. The Commission observes that in none of those cases was an allegation raised by any party, including the Public Staff, that Aqua NC's UPIS and unitization practices and policies did not conform with the Uniform System of Accounts or that the Company's depreciation practices were deficient in any way. Nor was there any indication that the accounting issues noted by the Public Staff in the Sub 274 rate case were not fully resolved.

However, in the present proceeding, as a result of Aqua NC's novel request for aggregate deferral accounting treatment and witnesses Henry and Junis investigation of the Company's plant additions dating back to 2015, the Public Staff discovered that the Company's approach for closing CWIP projects to plant in service was not being utilized consistently. Witnesses Henry and Junis informed the Commission that there are numerous projects that have been unitized by the Company in the same month, and sometimes even the same day, as being placed in service, while others are unitized months, or even years, after being placed in service. Further, witnesses Henry and Junis explained that the delay in unitizing the plant projects also delays the start of depreciation and in some instances the conclusion of AFUDC. Witnesses Henry and Junis stated that the Company's approach, which allows 30 to 60 days for any trailing costs to be charged to projects before closing the asset, would be acceptable to the Public Staff if utilized consistently and for an overwhelming majority of its CWIP projects.

The Commission agrees with the testimony of witnesses Henry and Junis that ideally, the in-service date should occur in the same month as the unitization date such that depreciation begins with the in-service date. The Commission also agrees that, without exception, the accrual of AFUDC should end on the in-service date of an asset. The Commission finds and concludes that Aqua NC's current UPIS unitization policy with respect to the commencement of depreciation would continue to be acceptable if utilized consistently by Aqua NC with strict adherence to a period of 30 to 60 days being allowed for any trailing costs to be charged to the projects before closing the asset to plant in service. Furthermore, Aqua NC should give particular attention to plant in-service dates occurring at the end of the calendar year such that the one-half year's depreciation expense is recorded in the year the plant is placed in service to the maximum extent possible.

In order that the Commission may fully and finally resolve this issue on a prospective basis, the Commission will require Aqua NC to conduct a comprehensive review of its current procedures and policies for determining when projects are complete, in-service, and booked to plant in service and file the Company's findings with respect to its internal accounting practices and policies and any plans or recommendations regarding changes in those procedures and policies within 90 days of the date of the Order in this proceeding. The purpose of this requirement is to evaluate the merits and challenges of establishing prospective practices and policies which are understood by the Company, the Public Staff, and the Commission so that issues such as those raised in this case do not arise in the future.

Moreover, Aqua NC's comprehensive review of its UPIS practices and policies should include an analysis of whether the Company can utilize the functionality provided by PowerPlan, discussed at the expert witness hearing by witnesses Junis and Thill, to book completed but not classified costs on the in-service date and on a continual basis shortly thereafter as invoices are received and paid until the entire project can be unitized to ensure that AFUDC ends and depreciation begins on the in-service date. Aqua NC and the Public Staff should work together to fully explore and address the UPIS issues and come to a consensus settlement, if possible, such that this matter will not be a litigated issue in a future rate case proceeding. Further, Aqua NC should report to the Commission regarding the status of the Company's evaluation and its proposed implementation plan and timeframe, if applicable. Upon filing of such analysis by Aqua NC, the Commission shall issue a further order either approving a change in Aqua NC's current UPIS practices and policies or continuing the Company's current practices and policies with stricter attention to specified guidelines as discussed herein.

In the interim, the Commission concludes that within 30 to 60 days after the in-service date for CWIP projects Aqua NC should record the CWIP costs to plant in service such that the projects begin depreciating. Moreover, the Commission concludes that Aqua NC should be particularly attentive to closing assets from CWIP to plant in service in the proper calendar year such that the half year's depreciation expense that should be taken on the Company's books and records in the first year the asset is placed in service begins in the appropriate calendar year. Finally, the Company should continue its current policy of ceasing AFUDC accrual as of the plant in-service date.

In reaching these conclusions, the Commission gives significant weight to the testimony of witness Thill regarding the volume of capital project transactions that occur in a given month and that project costs can be as simple as a single invoice or as complex as hundreds of lines of activity including vendor payments, internal payroll capitalizations, inventory assignments, overhead allocations and AFUDC assessments. The Commission also gives significant weight to the testimony of witness Thill that the accounting department must work with other departments within the Company to determine the in service date, to obtain required invoice approvals, and to make appropriate accounting entries, and that such communication between departments requires some necessary period of time to accomplish. Further, the Commission acknowledges the testimony of witness Thill that the Uniform System of Accounts guides utility accounting, supplemented by orders of the Commission. The Commission gives significant weight to the testimony of witness Thill that the Uniform System of Accounts' description of CWIP states that work orders shall be cleared from the CWIP account as soon as practicable after completion of the job. Consequently, the Commission concludes that Aqua NC should clear the CWIP account to plant in service once the project is completed as soon as practicable after completion of the project.

Further, the Commission gives significant weight to the testimony of witness Junis at the expert witness hearing regarding the "completed construction not classified" or "Account 106" function of PowerPlan that stops the accrual of AFUDC and begins depreciation when the asset is placed in service, while allowing for components of the asset to "continue to be accounted for during a designated period of time or until it is believed that all the costs have been captured." The Commission gives substantial weight to the Public Staff's uncontroverted testimony that the in-service date is the objective point in time when an asset is "used and useful," is installed, constructed, functional, and providing service. As of the in-service date, the asset is being utilized (i.e., water can flow, lift station can pump, etc.) and begins to devalue with the passage of time due to wear and tear, which is accounted for through depreciation over the expected life of the asset. Therefore, the Commission agrees with the Public Staff that the in-service date is the most appropriate point in time for depreciation to begin if Aqua NC's asset management system has the capability to accomplish that result for its North Carolina operations.

The Commission finds that the evidence in this proceeding demonstrates that the PowerPlan asset management program is widely utilized by the state's larger and more sophisticated utilities and contains a "completed construction not classified" or "Account 106" function that stops the accrual of AFUDC and begins depreciation when the asset is placed in service, while allowing for components of the asset to "continue to be accounted for during a designated period of time or until it is believed that all the costs have been captured." However, the Commission acknowledges that although witness Thill stated that generally speaking witness Junis correctly described the functionality of PowerPlan's Account 106 function, witness Thill noted that "knowledgeable Aqua NC staff had concerns about the viability of the 'completed but not yet categorized' functionality in Aqua North Carolina's particular case." Consequently, the Commission finds and concludes that Aqua NC should evaluate whether the Account 106 function of PowerPlan could track asset costs, which are associated with assets that have been placed in service, and depreciate such asset costs at the general depreciation rate of the related plant for a reasonable period of time or until all vendor invoices have been received and recorded in the Company's financial accounting records and should report to the Public Staff and the Commission regarding its findings. Such findings should be included with the aforementioned report filed with the Commission within 90 days of the issuance date of this Order.

Moreover, the Commission urges Aqua NC to consult with the Public Staff regarding the findings of its review of the Company's current procedures and policies for determining when projects are complete, in-service, and booked to plant in service and to work collaboratively with the Public Staff regarding changes in those procedures and policies such that this matter will not be a litigated issue in a future rate case proceeding.

With respect to the matters identified by the Public Staff regarding the Company's May 1, 2019 WSIC/SSIC Application, the Commission finds and concludes based upon the record evidence that the adjustments recommended by the Public Staff and agreed to in Paragraph I of the Stipulation to the in-service dates and associated accumulated depreciation, rate base, and return on certain projects related to the May 1, 2019 WSIC/SSIC Application are reasonable and appropriate to include in this rate case.

In regards to the adjustments to AFUDC recommended by the Public Staff, the Commission further finds and concludes based upon the record evidence that the adjustments recommended by the Public Staff to the in service dates, AFUDC, and associated accumulated depreciation, rate base, and return on certain capital expenditures unitized by the Company in the post-test year period in the present rate case and agreed to as part of the stipulated settlement are reasonable and appropriate to include in this rate case.

With respect to Aqua NC's policy for calculating AFUDC, the Commission finds and concludes that Aqua NC should file its current AFUDC policy with the Commission within 90 days of the issuance date of this Order. Such policy should set forth Aqua NC's calculation of its current AFUDC rate upon issuance of the Commission's final Order in this proceeding and should identify the established parameters (total dollar amount of the project, length of project construction, etc.) for projects to qualify for an AFUDC accrual.

Finally, with respect to the disagreement between the stipulating parties in this proceeding concerning whether Aqua NC should, as recommended by the Public Staff, be required to track and include as a regulatory accounting adjustment in all future rate cases until the applicable assets have fully depreciated or retired the stipulated adjustments to (1) the in-service dates and associated accumulated depreciation, rate base, and return on certain projects related to the May 1, 2019 WSIC/SSIC Application and (2) the in-service dates, AFUDC, and associated accumulated depreciation, rate base, and return on certain capital expenditures unitized by the Company in the post-test year period in the present rate case, the Commission declines to require such establishment of a regulatory accounting adjustment at this time. Rather, the Commission concludes that Aqua NC should be provided an opportunity to evaluate its current procedures for determining when projects are completed, in service, and booked to plant in service, to work collaboratively with the Public Staff regarding any plans to change those procedures, including any plans to implement the Account 106 feature of PowerPlan as discussed hereinabove, prior to the Commission requiring any further adjustments to Aqua NC's accumulated depreciation levels in a future rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 63–73

Ratemaking and Revenue Requirement Issues

The evidence in support of the ratemaking and revenue requirement findings of fact is found in the Stipulation and the testimony and exhibits of Aqua NC witnesses Becker, Thill, Gearhart, D'Ascendis, Berger, Hanley, Pearce, and Kunkel and Public Staff witnesses Henry, Feasel, Junis, Boswell, Hinton, Darden, and Franklin.

The following schedules summarize the gross revenues and rate of return that the Company should have a reasonable opportunity to achieve based on the increases and decreases in revenues approved in this Order for each rate entity. These schedules, illustrating the Company's gross revenue requirements, incorporate the adjustments found appropriate by the Commission in this Order.

SCHEDULE I

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Net Operating Income for a Return
For the Twelve Months Ended September 30, 2019
Combined Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$61,272,691	$3,446,081	$64,718,772
Late payment fees	105,583	6,597	112,180
Miscellaneous revenues	1,270,926	0	1,270,926
Uncollectibles & abatements	(336,714)	(25,775)	(362,489)
Total operating revenues	62,312,486	3,426,903	65,739,389
Operating Revenue Deductions:			
Salaries & wages	10,789,168	0	10,789,168
Employee pensions & benefits	3,161,501	0	3,161,501
Purchased water/sewer treatment	2,627,732	0	2,627,732
Sludge removal	760,234	0	760,234
Purchased power	3,878,492	0	3,878,492
Fuel for power production	18,494	0	18,494
Chemicals	1,330,863	0	1,330,863
Materials & supplies	535,914	0	535,914
Testing fees	1,062,424	0	1,062,424
Transportation	1,308,389	0	1,308,389
Contractual services-engineering	22,867	0	22,867
Contractual services-accounting	218,996	0	218,996
Contractual services-legal	372,517	0	372,517
Contractual services-other	4,646,229	0	4,646,229
Rent	295,836	0	295,836
Insurance	723,202	0	723,202
Regulatory commission expense	468,294	0	468,294
Miscellaneous expense	1,801,761	0	1,801,761
Interest on customer deposits	30,734	0	30,734
Annualization & consumption adjustments	98,917	0	98,917
Contra-OH allocations	(274,679)	0	(274,679)
Total O&M and G&A expense	33,877,885	0	33,877,885
Depreciation & amortization expense	10,733,726	0	10,733,726
Property taxes	678,027	0	678,027
Payroll taxes	772,558	0	772,558
Other taxes	288,922	0	288,922
Benefit costs - Pension	(1,251)	0	(1,251)
Regulatory fee	81,007	4,455	85,462
Deferred income tax	(121,271)	0	(121,271)
State income tax	272,249	85,560	357,809
Federal income tax	2,229,709	700,747	2,930,456
Total operating revenue deductions	48,811,561	790,762	49,602,323
Net operating income for return	$13,500,925	$2,636,141	$16,137,066

SCHEDULE II

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Original Cost Rate Base
For the Twelve Months Ended September 30, 2019
Combined Operations

Plant in service	$537,364,375
Accumulated depreciation	(151,179,665)
Contributions in aid of construction	(208,059,143)
Accumulated amortization of CIAC	80,039,515
Acquisition adjustments	2,159,025
Accum. amort. of acquisition adjustments	692,794
Advances for construction	(4,091,131)
Net plant in service	256,925,770
Customer deposits	(359,356)
Unclaimed refunds & cost-free capital	(193,255)
Accumulated deferred income taxes	(27,147,850)
Materials and supplies inventory	2,790,285
Excess capacity adjustment	0
Working capital allowance	5,119,829
Original cost rate base	$237,135,423

Rates of return:	
Present	5.69%
Approved	6.81%

SCHEDULE III

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Statement of Capitalization and Related Costs
For the Twelve Months Ended September 30, 2019
Combined Operations

	Ratio %	Original Cost Rate Base	Embedded Cost %	Net Operating Income
		PRESENT RATES		
Long-Term Debt	50.00	$118,567,712	4.21	$4,991,701
Common Equity	50.00	118,567,711	7.18	8,509,224
Total	100.00	$237,135,423		$13,500,925
		APPROVED RATES		
Long-Term Debt	50.00	$118,567,712	4.21	$4,991,701
Common Equity	50.00	118,567,711	9.40	11,145,365
Total	100.00	$237,135,423		$16,137,066

SCHEDULE I-A

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Net Operating Income for a Return
For the Twelve Months Ended September 30, 2019
Aqua NC Water Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$36,559,502	$1,986,987	$38,546,489
Late payment fees	62,868	3,417	66,285
Miscellaneous revenues	759,977	0	759,977
Uncollectibles & abatements	(172,554)	(9,378)	(181,932)
Total operating revenues	37,209,793	1,981,026	39,190,819
Operating Revenue Deductions:			
Salaries & wages	7,029,367	0	7,029,367
Employee pensions & benefits	2,041,979	0	2,041,979
Purchased water	1,787,711	0	1,787,711
Purchased power	2,368,986	0	2,368,986
Fuel for power production	(1,571)	0	(1,571)
Chemicals	460,830	0	460,830
Materials & supplies	378,521	0	378,521
Testing fees	681,418	0	681,418
Transportation	885,052	0	885,052
Contractual services-engineering	9,986	0	9,986
Contractual services-accounting	135,888	0	135,888
Contractual services-legal	228,668	0	228,668
Contractual services-other	2,189,056	0	2,189,056
Rent	209,235	0	209,235
Insurance	442,138	0	442,138
Regulatory commission expense	290,858	0	290,858
Miscellaneous expense	1,086,984	0	1,086,984
Interest on customer deposits	23,936	0	23,936
Annualization & consumption adjustments	58,269	0	58,269
Contra-OH allocations	(200,909)	0	(200,909)
Total O&M and G&A expense	20,106,402	0	20,106,402
Depreciation & amortization expense	6,770,258	0	6,770,258
Property taxes	534,225	0	534,225
Payroll taxes	493,985	0	493,985
Other taxes	179,292	0	179,292
Benefit costs - Pension	(504)	0	(504)
Regulatory fee	48,373	2,575	50,948
Deferred income tax	(75,322)	0	(75,322)
State income tax	155,422	49,461	204,883
Federal income tax	1,272,902)	405,088	1,677,990
Total operating revenue deductions	29,485,032	457,124	29,942,156
Net operating income for return	$7,724,761	$1,523,902	$9,248,663

SCHEDULE II-A

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Original Cost Rate Base
For the Twelve Months Ended September 30, 2019
Aqua NC Water Operations

Plant in service	$297,497,315
Accumulated depreciation	(90,717,400)
Contributions in aid of construction	(98,979,231)
Accumulated amortization of CIAC	37,254,305
Acquisition adjustments	6,192,960
Accum. amort. of acquisition adjustments	(2,433,069)
Advances for construction	(2,748,037
Net plant in service	146,066,843
Customer deposits	(281,444)
Unclaimed refunds & cost-free capital	(46,582)
Accumulated deferred income taxes	(15,220,457)
Materials and supplies inventory	2,235,302
Excess capacity adjustment	0
Working capital allowance	3,156,148
Original cost rate base	$135,909,810

Rates of return:	
Present	5.69%
Approved	6.81%

SCHEDULE III-A

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Statement of Capitalization and Related Costs
For the Twelve Months Ended September 30, 2019
Aqua NC Water Operations

	Ratio %	Original Cost Rate Base	Embedded Cost %	Net Operating Income
		PRESENT RATES		
Long-Term Debt	50.00	$67,954,905	4.21	$2,860,902
Common Equity	50.00	67,954,905	7.16	4,863,859
Total	100.00	$135,909,810		$7,724,761
		APPROVED RATES		
Long-Term Debt	50.00	$67,954,905	4.21	$2,860,902
Common Equity	50.00	67,954,905	9.40	6,387,761
Total	100.00	$135,909,810		$9,248,663

SCHEDULE I-B

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Net Operating Income for a Return
For the Twelve Months Ended September 30, 2019
Aqua NC Sewer Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$15,607,641	$818,429	$16,426,070
Late payment fees	18,813	987	19,800
Miscellaneous revenues	32,029	0	32,029
Uncollectibles & abatements	(19,331)	(1,014)	(20,345)
Total operating revenues	15,639,152	818,402	16,457,554
Operating Revenue Deductions:			
Salaries & wages	2,424,519	0	2,424,519
Employee pensions & benefits	696,455	0	696,455
Purchased sewer	570,367	0	570,367
Sludge removal	590,239	0	590,239
Purchased power	1,054,929	0	1,054,929
Fuel for power production	19,318	0	19,318
Chemicals	520,589	0	520,589
Materials & supplies	98,861	0	98,861
Testing fees	281,394	0	281,394
Transportation	301,127	0	301,127
Contractual services-engineering	11,385	0	11,385
Contractual services-accounting	35,728	0	35,728
Contractual services-legal	64,081	0	64,081
Contractual services-other	1,430,357	0	1,430,357
Rent	42,751	0	42,751
Insurance	177,221	0	177,221
Regulatory commission expense	76,800	0	76,800
Miscellaneous expense	407,765	0	407,765
Interest on customer deposits	683	0	683
Annualization & consumption adjustments	49,804	0	49,804
Contra-OH allocations	(50,524)	0	(50,524)
Total O&M and G&A expense	8,803,849	0	8,803,849
Depreciation & amortization expense	2,434,103	0	2,434,103
Property taxes	17,637	0	17,637
Payroll taxes	205,084	0	205,084
Other taxes	47,134	0	47,134
Benefit costs - Pension	(474)	0	(474)
Regulatory fee	20,331	1,064	21,395
Deferred income tax	(19,888)	0	(19,888)
State income tax	71,017	20,433	91,450
Federal income tax	581,626	167,350	748,976
Total operating revenue deductions	12,160,420	188,847	12,349,267
Net operating income for return	$3,478,732	$629,555	$4,108,287

SCHEDULE II-B

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Original Cost Rate Base
For the Twelve Months Ended September 30, 2019
Aqua NC Sewer Operations

Plant in service	$165,414,907
Accumulated depreciation	(44,951,137)
Contributions in aid of construction	(84,910,644)
Accumulated amortization of CIAC	32,786,629
Acquisition adjustments	(4,002,509)
Accum. amort. of acquisition adjustments	3,096,868
Advances for construction	(1,287,424)
Net plant in service	66,146,690
Customer deposits	(7,128)
Unclaimed refunds & cost-free capital	(6,342)
Accumulated deferred income taxes	(7,249,727)
Materials and supplies inventory	400,302
Excess capacity adjustment	0
Working capital allowance	1,087,814
Original cost rate base	$60,371,609

Rates of return:	
Present	5.76%
Approved	6.81%

SCHEDULE III-B

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Statement of Capitalization and Related Costs
For the Twelve Months Ended September 30, 2019
Aqua NC Sewer Operations

	Ratio %	Original Cost Rate Base	Embedded Cost %	Net Operating Income
		PRESENT RATES		
Long-Term Debt	50.00	$30,185,804	4.21	$1,270,822
Common Equity	50.00	30,185,805	7.31	2,207,910
Total	100.00	$60,371,609		$3,478,732
		APPROVED RATES		
Long-Term Debt	50.00	$30,185,804	4.21	$1,270,822
Common Equity	50.00	30,185,805	9.40	2,837,465
Total	100.00	$60,371,609		$4,108,287

SCHEDULE I-C

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Net Operating Income for a Return
For the Twelve Months Ended September 30, 2019
Fairways Water Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$1,138,759	$20,949	$1,159,708
Late payment fees	1,621	30	1,651
Miscellaneous revenues	91,092	0	91,092
Uncollectibles & abatements	(2,544)	(47)	(2,591)
Total operating revenues	1,228,928	20,932	1,249,860
Operating Revenue Deductions:			
Salaries & wages	267,676	0	267,676
Employee pensions & benefits	85,115	0	85,115
Purchased water	0	0	0
Purchased power	75,588	0	75,588
Fuel for power production	(209)	0	(209)
Chemicals	24,115	0	24,115
Materials & supplies	9,810	0	9,810
Testing fees	19,827	0	19,827
Transportation	21,442	0	21,442
Contractual services-engineering	323	0	323
Contractual services-accounting	10,230	0	10,230
Contractual services-legal	17,214	0	17,214
Contractual services-other	151,349	0	151,349
Rent	14,202	0	14,202
Insurance	16,629	0	16,629
Regulatory commission expense	22,197	0	22,197
Miscellaneous expense	61,683	0	61,683
Interest on customer deposits	558	0	558
Annualization & consumption adjustments	(5,834)	0	(5,834)
Contra-OH allocations	(2,539)	0	(2,539)
Total O&M and G&A expense	789,376	0	789,376
Depreciation & amortization expense	133,475	0	133,475
Property taxes	30,683	0	30,683
Payroll taxes	14,300	0	14,300
Other taxes	13,481	0	13,481
Benefit costs - Pension	(147)	0	(147)
Regulatory fee	1,598	27	1,625
Deferred income tax	(5,748)	0	(5,748)
State income tax	4,394	522	4,916
Federal income tax	35,984	4,281	40,265
Total operating revenue deductions	1,017,396	4,830	1,022,226
Net operating income for return	$211,532	$16,102	$227,634

SCHEDULE II-C

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Original Cost Rate Base
For the Twelve Months Ended September 30, 2019
Fairways Water Operations

Plant in service	$13,024,429
Accumulated depreciation	(3,544,128)
Contributions in aid of construction	(8,239,542)
Accumulated amortization of CIAC	2,419,869
Acquisition adjustments	0
Accum. amort. of acquisition adjustments	0
Advances for construction	(69,670)
Net plant in service	3,590,957
Customer deposits	(5,931)
Unclaimed refunds & cost-free capital	(7,339)
Accumulated deferred income taxes	(380,042)
Materials and supplies inventory	21,017
Excess capacity adjustment	0
Working capital allowance	126,431
Original cost rate base	$3,345,093

Rates of return:	
Present	6.33%
Approved	6.81%

SCHEDULE III-C

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Statement of Capitalization and Related Costs
For the Twelve Months Ended September 30, 2019
Fairways Water Operations

	Ratio %	Original Cost Rate Base	Embedded Cost %	Net Operating Income
		PRESENT RATES		
Long-Term Debt	50.00	$1,672,547	4.21	$70,414
Common Equity	50.00	1,672,546	8.44	141,118
Total	100.00	$3,345,093		$211,532
		APPROVED RATES		
Long-Term Debt	50.00	$1,672,547	4.21	$70,414
Common Equity	50.00	1,672,546	9.40	157,220
Total	100.00	$3,345,093		$227,634

SCHEDULE I-D

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Net Operating Income for a Return
For the Twelve Months Ended September 30, 2019
Fairways Sewer Operations

	Present Rates	Decrease Approved	After Approved Decrease
Operating Revenues:			
Service revenues	$2,189,589	$(37,003)	$2,152,586
Late payment fees	2,833	(48)	2,785
Miscellaneous revenues	40	0	40
Uncollectibles & abatements	(6,413)	109	(6,304)
Total operating revenues	2,186,049	(36,942)	2,149,107
Operating Revenue Deductions:			
Salaries & wages	235,581	0	235,581
Employee pensions & benefits	74,007	0	74,007
Purchased sewer	5,320	0	5,320
Sludge removal	169,995	0	169,995
Purchased power	107,989	0	107,989
Fuel for power production	1,569	0	1,569
Chemicals	28,526	0	28,526
Materials & supplies	14,503	0	14,503
Testing fees	13,848	0	13,848
Transportation	23,554	0	23,554
Contractual services-engineering	207	0	207
Contractual services-accounting	6,544	0	6,544
Contractual services-legal	11,020	0	11,020
Contractual services-other	147,857	0	147,857
Rent	8,916	0	8,916
Insurance	21,869	0	21,869
Regulatory commission expense	14,142	0	14,142
Miscellaneous expense	53,820	0	53,820
Interest on customer deposits	8	0	8
Annualization & consumption adjustments	(10,321)	0	(10,321)
Contra-OH allocations	(2,807)	0	(2,807)
Total O&M and G&A expense	926,147	0	926,147
Depreciation & amortization expense	342,524	0	342,524
Property taxes	2,322	0	2,322
Payroll taxes	15,183	0	15,183
Other taxes	8,619	0	8,619
Benefit costs - Pension	(137)	0	(137)
Regulatory fee	2,842	(48)	2,794
Deferred income tax	(3,662)	0	(3,662)
State income tax	16,722	(922)	15,800
Federal income tax	136,955	(7,554)	129,401
Total operating revenue deductions	1,447,515	(8,524)	1,438,991
Net operating income for return	$738,534	($28,418)	$710,116

SCHEDULE II-D

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Original Cost Rate Base
For the Twelve Months Ended September 30, 2019
Fairways Sewer Operations

Plant in service	$20,037,782
Accumulated depreciation	(2,601,325)
Contributions in aid of construction	(7,928,978)
Accumulated amortization of CIAC	2,005,203
Acquisition adjustments	0
Accum. amort. of acquisition adjustments	0
Advances for construction	14,000
Net plant in service	11,526,682
Customer deposits	(92)
Unclaimed refunds & cost-free capital	(217)
Accumulated deferred income taxes	(1,223,091)
Materials and supplies inventory	7,306
Excess capacity adjustment	0
Working capital allowance	124,618
Original cost rate base	$10,435,206

Rates of return:	
Present	7.08%
Approved	6.81%

SCHEDULE III-D

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Statement of Capitalization and Related Costs
For the Twelve Months Ended September 30, 2019
Fairways Sewer Operations

	Ratio %	Original Cost Rate Base	Embedded Cost %	Net Operating Income
		PRESENT RATES		
Long-Term Debt	50.00	$5,217,603	4.21	$219,661
Common Equity	50.00	5,217,603	9.94	518,873
Total	100.00	$10,435,206		$738,534
		APPROVED RATES		
Long-Term Debt	50.00	$5,217,603	4.21	$219,661
Common Equity	50.00	5,217,603	9.40	490,455
Total	100.00	$10,435,206		$710,116

SCHEDULE I-E

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Net Operating Income for a Return
For the Twelve Months Ended September 30, 2019
Brookwood Water Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$5,777,200	$656,719	$6,433,919
Late payment fees	19,448	2,211	21,659
Miscellaneous revenues	387,788	0	387,788
Uncollectibles & abatements	(135,872)	(15,445)	(151,317)
Total operating revenues	6,048,564	643,485	6,692,049
Operating Revenue Deductions:			
Salaries & wages	832,025	0	832,025
Employee pensions & benefits	263,945	0	263,945
Purchased water	264,334	0	264,334
Purchased power	271,000	0	271,000
Fuel for power production	(613)	0	(613)
Chemicals	296,803	0	296,803
Materials & supplies	34,219	0	34,219
Testing fees	65,937	0	65,937
Transportation	77,214	0	77,214
Contractual services-engineering	966	0	966
Contractual services-accounting	30,606	0	30,606
Contractual services-legal	51,534	0	51,534
Contractual services-other	727,610	0	727,610
Rent	20,732	0	20,732
Insurance	65,345	0	65,345
Regulatory commission expense	64,297	0	64,297
Miscellaneous expense	191,509	0	191,509
Interest on customer deposits	5,549	0	5,549
Annualization & consumption adjustments	6,999	0	6,999
Contra-OH allocations	(17,900)	0	(17,900)
Total O&M and G&A expense	3,252,111	0	3,252,111
Depreciation & amortization expense	1,053,366	0	1,053,366
Property taxes	93,160	0	93,160
Payroll taxes	44,006	0	44,006
Other taxes	40,396	0	40,396
Benefit costs - Pension	11	0	11
Regulatory fee	7,863	837	8,700
Deferred income tax	(16,651)	0	(16,651)
State income tax	24,694	16,066	40,760
Federal income tax	202,242	131,582	333,824
Total operating revenue deductions	4,701,198	148,485	4,849,683
Net operating income for return	$1,347,366	$495,000	$1,842,366

SCHEDULE II-E

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Original Cost Rate Base
For the Twelve Months Ended September 30, 2019
Brookwood Water Operations

Plant in service	$41,389,941
Accumulated depreciation	(9,365,674)
Contributions in aid of construction	(8,000,748)
Accumulated amortization of CIAC	5,573,511
Acquisition adjustments	(31,426)
Accum. amort. of acquisition adjustments	28,995
Advances for construction	0
Net plant in service	29,594,599
Customer deposits	(64,761)
Unclaimed refunds & cost-free capital	(132,775)
Accumulated deferred income taxes	(3,074,533)
Materials and supplies inventory	126,358
Excess capacity adjustment	0
Working capital allowance	624,818
Original cost rate base	$27,073,706

Rates of return:	
Present	4.98%
Approved	6.81%

SCHEDULE III-E

Aqua North Carolina, Inc.
Docket No. W-218, Sub 526
Statement of Capitalization and Related Costs
For the Twelve Months Ended September 30, 2019
Brookwood Water Operations

	Ratio %	Original Cost Rate Base	Embedded Cost %	Net Operating Income
		PRESENT RATES		
Long-Term Debt	50.00	$13,536,853	4.21	$569,902
Common Equity	50.00	13,536,853	5.74	777,464
Total	100.00	$27,073,706		$1,347,366
		APPROVED RATES		
Long-Term Debt	50.00	$13,536,853	4.21	$569,902
Common Equity	50.00	13,536,853	9.40	1,272,464
Total	100.00	$27,073,706		$1,842,366

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 74-76

Water System Improvement Charge (WSIC) and Sewer System Improvement Charge (SSIC)

In the Company's general rate case proceeding in Docket No. W-218, Sub 363, the Commission found it to be in the public interest to authorize Aqua NC to implement and utilize a rate adjustment mechanism (WSIC/SSIC rate adjustment mechanism) to recover the incremental depreciation expense and capital costs related to eligible investments in water and sewer infrastructure projects completed and placed in service between general rate case proceedings, as provided for in the then-newly enacted G.S. 62-133.12. Thus, Aqua NC was authorized to implement a WSIC/SSIC rate adjustment mechanism for recovery of such costs applicable to all of the Company's customers.

The Ongoing Three-Year WSIC/SSIC Plan filed by Aqua NC in Docket No. W-218, Sub 497A on March 2, 2020, is reasonable and meets the requirements of Commission Rules R7-39(m) pertaining to the WSIC and R10 26(m) pertaining to the SSIC.

The Commission's previously-authorized water and sewer system improvement charge rate adjustment mechanism for Aqua NC continues in effect, although, pursuant to Commission Rules R7-39(k) and R10-26(k), it has been reset at zero as of the date this Order is issued. Aqua NC may, under the Rules and Regulations of the Commission, next apply for a WSIC/SSIC rate surcharge on November 1, 2020, to become effective January 1, 2021. 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 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 general rate case proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 77–83

Customer Concerns - Service and Water Quality Related Issues

The evidence supporting these findings of fact is contained in the testimony and exhibits of the public witnesses, the verified reports filed by Aqua NC and the Public Staff in response to the concerns testified to by the public witnesses, and the entire record in this proceeding.

A public witness hearing was held via WebEx on Monday, August 3, 2020, for the purpose of receiving the testimony of non-expert, public witnesses. A total of 24 customers testified during the hearing. Fifteen of the 24 witnesses testified that the poor quality of the water supplied by Aqua NC caused serious problems, including discoloration of fixtures, damage to appliances, and inability or difficulty using water for drinking, cooking, bathing, and cleaning. Several witnesses testified that they opposed the Company's requested rate increase. The customers' testified regarding how the secondary water quality concerns they experience at their homes causes them stress, disrupts their daily lives, causes them to incur significant expense to repair and replace damaged appliances and plumbing fixtures, and to purchase bottled water for drinking and cooking. The concerns voiced by these witnesses relate to the high concentrations of iron and manganese in their water. The secondary water quality concerns of the customer witnesses appearing before the Commission in this docket were essentially the same in nature as those of customer witnesses who testified at the public hearings held in the Sub 319, 363, and 497 dockets in 2011, 2013, and 2018, respectively. However, the number of customers filing written complaints or testifying at the public witness hearing to lodge complaints was significantly less than for prior Aqua NC rate cases.

In addition to the effects of high concentrations of iron and manganese on their personal property, some witnesses who testified in this docket expressed concerns about the potential effects of these elements on their health and the health of their families. Six witnesses testified regarding Aqua's use of flushing to reduce the effects of iron and manganese in their water. Of those six, three customers testified that they received notice of the flushing and that it helps improve secondary water quality, and three witnesses testified regarding inadequate notice of flushing, excessive flushing and the cost of water used for flushing[1]. Several witnesses testified that they had installed water filtration systems in their homes at significant cost to them because of the poor water quality supplied to their homes by the Company.

Some of the witnesses, who testified about issues related to poor water quality also testified about issues with Aqua NC's customer service. They testified about the lack of responsiveness to customer communications. It should be noted that some customers praised Aqua NC for the progress it has made in improving customer service following the Sub 497 proceeding.

Most wastewater customers expressed frustration with flat rate sewer service. Five wastewater customers testified that they would prefer metered sewer service and two other wastewater customers testified that they would be interested in exploring whether metered sewer service would cost less than the current base charge.

Aqua NC's verified reports on customer comments addressed the concerns raised by the witnesses at the public witness hearing. In its Report on Customer Comments from Public Hearings held on August 3, 2020, filed on August 24, 2020, Aqua NC reported that it spoke to, met with, or otherwise attempted to contact the witnesses who testified at the hearing to discuss their concerns, address their concerns, and provide helpful explanations and answers regarding issues they raised. Aqua NC informed customers that, with regard to secondary water quality issues, the Company has invested a great deal of time, effort, and resources trying to improve secondary water quality issues related to the presence of iron and manganese in the water supply used to serve its customers. Aqua NC explained that over the years and continuing to date, it has implemented iron and manganese removal techniques such as flushing, oxidation, sedimentation and filtration, including the installation of expensive manganese dioxide filters. Aqua NC stated that since 2015 the Company has installed 46 iron and manganese filters statewide at a cost of $16.8 million and 56 cartridge filters at a cost of $218,000. The Company's combined investment in filtration totals over $17 million. Aqua NC stated it implemented an aggressive water quality operational plan in January 2018 to ensure that water quality is addressed pending the completion of requisite capital

[1] Per Aqua NC, when flushing is conducted or suggested by the Company, customers receive a billing credit.

improvements. In addition to the filter installations, Aqua's water quality plan included the launch of a tank cleaning project, an in-house water quality monitoring program, and development of a rigorous flushing plan for those systems with the highest level of minerals causing secondary water quality complaints.

Aqua NC also addressed customer concerns regarding customer service. The Company stated that it has made several improvements to its local communications efforts since its last rate case using customer input from its customer focus group, including: (1) improved messaging regarding flushing campaigns using WaterSmart Alert; (2) increased use of local signage at community entrances and exits for awareness of flushing activities while a campaign is in progress; and (3) addition of a bit.ly link on WaterSmart text messages that links customers to a site with a comprehensive message.

Aqua NC also stated in its report that it provides a broad range of options and resources for both one-way alerts and two-way communications. These include the Company's website, call center, personal contact from field operators, and its customer experience program (CX Program). The Company explained that the CX Program is intended to highlight the Company's commitment to the core values of respect, integrity, and the pursuit of excellence. The program was formally launched at the end of 2019 and has included a formal customer survey, CX working groups focused on improving communications with customers, and residential water customer journey mapping which maps every touchpoint residential water customers have with Aqua NC from the start of service and includes every possible interaction a customer may have with Aqua NC.

The Public Staff filed its verified response to Aqua's report on customer concerns on September 4, 2020, noting that it is concerned that customers contacting Aqua regarding an unreasonably high water bill cannot obtain a printout of the AMR 40 daily meter readings. In Aqua's verified reply comments filed on September 11, 2020, the Company states that 40-day AMR history is currently available for review with customers, but this read history had "only recently been made available, and Aqua[NC]'s Customer Service Representatives . . . are early in the learning curve." The Company further stated that while its daily reads are available for customers, the platform for customer use is not currently available. The Public Staff expressed frustration with Aqua's lack of progress in making this data available to its customers despite prior assurances that such a platform would be developed.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 84–91

Quality, Remediation Efforts, Environmental Compliance and Communication

The evidence supporting these findings of fact is contained in the testimony and exhibits of Aqua NC witnesses Becker and Berger, Public Staff witness Franklin, the determinations in the Sub 363 and Sub 497 Orders, the filings in the Sub 497A docket, and the record in this proceeding.

Quality and Remediation Efforts

As demonstrated by Becker Direct Exhibit 3, filed on December 31, 2019, Aqua NC's annual spend has ranged from $14 million in 2013 to a projected high of nearly $39 million through the end of 2019. The Company has invested heavily in infrastructure necessary to meet service and regulatory compliance standards within its nearly one thousand water and wastewater treatment, distribution, and collection systems across the state. Aqua NC has strengthened its focus on water quality improvement through its operation of the Company's Water Quality Plan, as described by witness Berger, which has required significant investment in filtration and water treatment to address naturally-occurring components of groundwater in efforts to improve service.

Witness Berger testified that since 2015 and through December 31, 2019, the Sub 526 Rate Case Application filing date, Aqua NC has installed forty-one manganese dioxide filters for a total capital investment spend of just under $15 million. The average removal rate by the manganese dioxide filters is 99.97% for iron removal and 99.95% for removal of manganese. In 2020, Aqua plans to install an additional eight (8) filters at Group 1 locations[1] with a capital expenditure of approximately $2.7 million. Witness Berger testified that while work remains to be done, water quality has improved and both notices of deficiencies and customer complaints have been reduced. The Water Quality Plan initiated in 2018 identified 92 wells as Group 1 locations. Tr. vol. 8, 24.

Witness Berger testified that currently Aqua has 67 Entry Points statewide that are listed as Group 1 (Fe + Mn > 1.0 mg/L or Mn> 0.3 mg/L). Of those:

- Three (3) have filters scheduled to be installed in 2020
- Three (3) have filters currently in engineering design
- Eight (8) are awaiting Public Staff concurrence and support
- Two (2) are in draft Executive Summary form for future submittal to the Public Staff for review
- Fifteen (15) are offline and are not providing water to the systems
- Twelve (12) have alternative treatment or other sources of supply
- The remaining 23 are all undergoing prudency evaluation for future Executive Summaries and consideration for manganese dioxide filtration
- Thirteen (13) filters have been installed since 2018 (inception of Secondary Water Quality Program) on sites identified as Group 1 (Fe + Mn > 1.0 mg/L: Mn > 0.3 mg/L)

Id. at 16

Aqua NC witness Becker testified that in the eighteen months since the post-test-year ended in Aqua's last rate case filing (June 30, 2018), Aqua has installed twelve new iron and manganese ("Fe/Mn") filters along with thirteen cartridge filters at a cost of nearly $4.6 million to help address secondary water quality issues in various systems. Tr. vol. 2, 122.

Aqua NC witness Berger addressed water and wastewater compliance for the Company, focusing on the Company's Water Quality Plan, including secondary water quality and emerging

[1] The highest priority for filtration.

contaminants. She updated Dr. Christopher Crockett's discussion from the Company's last rate case which addressed Aqua NC's Water Quality Plan and the Company's goal to prioritize infrastructure improvements necessary to address secondary water quality issues. Aqua NC utilizes a combination of increased capital and operational process improvement to address secondary water quality issues within the Company's Water Quality Plan. The Company's Plan identifies capital and process needs to address each system's water quality issues and establishes a prioritization methodology. Examples of capital and process improvement needs include (but are not limited to) treatment options or filtration along with tank cleaning. This Plan works to develop a common framework to address secondary water quality issues with support from the DEQ, thereby collaboratively engaging regulatory stakeholders. Tr. vol. 8, 17.

Witness Berger explained that Aqua NC's continued collaboration with the Public Staff on the development and submission of "Executive Summaries" is an important part of the process for evaluation and recovery through the Water System Improvement Charge ("WSIC") of installation of secondary water quality treatment filters. The Public Staff and Aqua NC collaborate on a review of these requests. The Executive Summaries are voluminous documents that include detailed data requests from the Public Staff and are the subject of meetings between the parties for purposes of review. *Id.* at 16.

Finally, witness Berger testified that customer complaints, as measured by the quantity of Lab D (Discolored Water) and Lab A (Aerated Water) work orders that are issued when a customer calls (during business and after hours) regarding a discolored water complaint, have declined over the past several years. *Id.* at 25. Data gathered on these water quality work orders between 2017 – 2019 demonstrates a 24.5% decline statewide, in 2019, from 2017 numbers. Additionally, the water quality work orders related to the Bayleaf master system decreased by 49% over this same period of time and Aqua NC projects a 76% decline in that system from 2017 to 2020. Berger Revised Rebuttal Exhibit 3.

Witness Berger further testified that Aqua NC has upgraded its operational efforts to address secondary water quality issues by the addition of a dedicated staff member to facilitate the handling of discolored water calls captured via the issuance of Lab D Work Orders, resulting in a decline in those work orders. Lab D Work Orders are now assigned to the Technical Services Specialist, who is the liaison between the customer and operations Field Service Representative. Tr. vol. 8, 16.

With respect to Aqua NC's flushing plan for those systems with the highest level of minerals causing secondary water quality complaints, witness Berger testified in response to questions from Commissioner Brown-Bland that COVID-19 prompted the Company to temporarily suspend certain flushing activities "until life resumes a little bit more normal". *Id.* at 180. The Commission finds that Aqua NC should strive to return to its pre-COVID-19 level of flushing activities as soon as reasonably possible to improve water quality for its customers experiencing secondary water quality issues.

Environmental Compliance—Water

A significant change in 2016 to DEQ standards concerning iron and manganese produced a profusion of Notices of Deficiency ("NODs") for Aqua which were triggered by exceedances in secondary limitations for iron and manganese. Aqua received a total of 68 NODs for all three qualitative tiers. Prior to February 2016, Aqua had only received NODs for exceeding sMCLs for iron and manganese five times since 2011. Tr. vol. 8, 22-23. Witness Berger testified on rebuttal that Aqua NC had achieved success in obtaining DEQ rescission of 55 of the 68 NODs issued in 2016 totaling an 81% reduction. Aqua NC's performance in reducing the levels of iron and manganese was commended in writing by the former Raleigh Regional Supervisor, DEQ. Tr. vol. 8, 134.

Additionally, witness Berger testified that calls from Aqua NC customers regarding discolored water increased 23% during the first quarter of 2020 as compared with the first quarter of 2019. *Id.* at 42.

Environmental Compliance—Wastewater

In 2018, eleven individual Aqua NC systems received 36 NOVs. Twenty-four of the NOVs were for Neuse Colony based on monitoring reporting frequency. These violations were the result of a permit being issued late in the compliance period and changes in terms from the permit between its drafting and its issuance. Additionally, the violations were issued near the time Hurricane Florence struck the area. Aqua NC confirmed that the operator overlooked the permit and essentially missed some sampling during that period of time. Following that incident, Aqua NC instituted Quality Control checks that jointly involved Operations and Compliance to prevent future recurrence of a similar incident. While Aqua NC did commit the error, there was no environmental impact from the violations. Additionally, witness Berger testified that the Quality Control measures implemented helped formalize the permit receipt and implementation schedule. *Id.* at 43-44.

In 2019, twenty-eight individual systems were issued a total of 66 NOVs. Twelve were paperwork errors, caused by software that Aqua NC utilized to generate Discharge Monitoring Reports. Aqua NC corrected the error and resubmitted the reports; however, the violation stands. Thirty-two of the violations were associated with the Neuse Colony wastewater treatment plant. During the January through April 2019 time period, the plant was at capacity and Aqua NC had difficulty maintaining the biology of the wastewater treatment plant due to cold weather, impacts from Hurricane Florence and working to complete the Johnston County interconnect. Since the Johnston County interconnect was completed in April 2019, the Company has been in compliance at Neuse Colony. *Id.* at 45-46.

Witness Berger also described the unique environmental issues associated with Wildwood Green. A permit was issued in early-2018 which assigned not only lower Neuse River Basin nutrient loading, but also nutrient loading for Falls Lake to one plant. The plant was never designed for nutrient removal and thus it was very difficult to meet permit limits. Aqua NC and DEQ collaborated on a pilot project to make some minor alterations to the treatment systems, which accomplished some nutrient removal, and a bubble permit, which combined the nutrient limit for both Hawthorne and Wildwood Green which are both within the same basin. The pilot program and bubble permit allowed Aqua NC to avoid the expense of upgrading the facility. The eleven NOVs that were issued in January 2019, were essentially rescinded by DEQ through the issuance of the new permit. *Id.* at 46-47.

Aqua NC received three violations in early 2020 for its Olde Beau plant. These violations were the result of an unauthorized third-party dumping chemicals into the waste stream which impacted the biological activity at the plant. Because the Olde Beau plant is a smaller facility, correcting the biological balance is very difficult. *Id.* at 47-48.

In early 2020, Aqua NC received an NOV for Chapel Ridge based on a sanitary sewer overflow caused by an electrical malfunction at a lift station. Aqua NC has requested rescission of the NOV and the related civil penalty. The bases for rescission of the NOV are that the electrical malfunction could not have been prevented. Aqua NC took immediate remedial action; and the Company made upgrades at its other facilities to ensure that the failure could not be replicated. *Id.* at 48-49.

Communications

Company witness Becker testified that to further focus on communications with its customers, especially as it relates to better communications about water quality issues, Aqua NC developed and implemented its communications plan called "Close the Loop" which ensures that an Aqua NC employee contacts every customer who calls with a complaint as a means of follow-up after the customer's call or complaint has been addressed. Tr. vol. 3, 52-53.

Witness Berger testified that Aqua NC's Communications Plan improves its ability to effectively convey to customers news of its water quality remediation efforts, timing, and education. The February 2018 roll-out of a project website for customers to learn more about the program and Aqua NC's actions deployed a useful resource, www.ncwaterquality.com. The website combines with other modes of communication to allow the Company to share ongoing updates about progress. Witness Berger stated that it is actively utilized and regularly updated to provide a status of current capital filtration projects being considered and includes copies of letters sent to communities identifying water quality improvement projects completed in those communities. Additionally, Aqua NC utilizes this site to better inform Bayleaf customers of the flushing schedule for the Bayleaf System. In addition to calling, emailing, or texting customers, the use of an updated weekly schedule on the website has resulted in positive feedback from customers and a significant decline in Lab D work orders related to flushing activities received during this time, compared to previous years. Tr. vol. 8, 25-26.

Regarding communication and outreach, witness Berger testified that in May of 2019, Aqua NC established the Bayleaf Advisory Group for its largest and most complex public water system. The group is comprised of Aqua NC staff and nine Bayleaf customers. To date, Aqua NC has held three meetings and discussed various topics from water quality, operations, flushing efforts, educational materials, and other items. The feedback from customers has been utilized to update processes and improve communications. Tr. vol. 8, 26. In her consumer statement of position filed on June 9, 2020, Bayleaf customer, Ms. Becky Daniel, confirmed Aqua NC's improved performance in Bayleaf, including reference to the Advisory Group and to generally improved responses.

Discussion and Conclusions

The Commission finds that though some customer concerns persist, particularly in certain parts of Aqua NC's service territory regarding secondary water quality, including odor and staining attributes when the secondary elements exist at high levels in the water, the ~~Company's~~ evidence showed significantly increased investment and operational attention to these issues. The Commission concludes that the Company's efforts are responsive to customer concerns, reflect additional investment and operational diligence, and, if sustained, should support continued improvement in secondary water quality and service. No party presented any evidence in this proceeding contrary to this conclusion.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 92–100

Regulatory Oversight and Compliance – Reporting Requirements

Aqua NC Witness Becker

During his direct testimony Company witness Becker testified regarding issues related to Aqua's water quality, customer service, and communications. He also introduced Aqua NC's concerns regarding the filing and reporting requirement prescribed in the Sub 497 Order. He provided an overview of the filings and reports that Aqua NC has completed under the terms of the Sub 363 and Sub 497 rate case Orders in his pre-filed direct testimony. Tr. vol. 2, 122-133. The table below lists each reporting requirement and identifies the source of the requirements. The table also includes the number of filings made by the Company pursuant to each requirement.

WATER AND SEWER – RATE INCREASE

Reporting Requirement	Ordering Document	Date of First Filing[1]	Number of Filings
Bi-monthly Report on Water Quality Issues	Sub 363, OP 8	May 2014	34
Semiannual Report Regarding Secondary Water Quality Concerns	Sub 363, OP 11 and 497, OP 10	August 2014	13
DEQ Quarterly Notice of Deficiency	Sub 497, OP 11	January 2019	16
Three Year WSIC/SSIC Plan	Sub 363 and 497; Commission Rules R7-39(m) and R10-26(m)	April 2015	6
Aqua NC Quarterly Earnings, WSIC/SSIC Revenue and Construction Status Reports	Sub 363 OP 10, Sub 497; Commission Rules R7-39(n) and R10-26(n)	May 2014	28
Application for Water, Sewer System Improvement Charge Rate Adjustments	Sub 363A; N.C.G.S. § 62-133.12 and Commission Rules R7-39 and R10-26	October 2014	12
Annual Heater Acquisition Incentive Account Report	Sub 319 and 497	June 2012	9
Secondary Water Quality Filtration Request Executive Summary	Sub 497, OP 11		30[2]
Amendments to Tariffs Detailing Connection/ Capacity Fees	Sub 497, OP 24	May 2019	1
Future Accounting Treatment of Johnston County Transmission and Capacity Fees	Sub 497, OP 25	March 2019	1
NC Water Quality Plan and Customer Communication Plan	Sub 497, OP 15 and OP 16	March 2019	1
Report on Investigation and Evaluation of Possibility of Entering into Agreements with Vendors of Home Filtration Water Systems and Replacement Filters for a Discount	Sub 497, OP 17	March 2019	2
Aqua NC Proposed Policy and Procedure of Providing Customers a Bill Credit	Sub 497, OP 20	June 2019	1

[1] Based on filings in Docket Nos. W-218, Sub 316, Sub 363A, and Sub 497A as of August 13, 2020.

[2] Based on prefiled direct testimony of Aqua NC witness Becker.

Reporting Requirement	Ordering Document	Date of First Filing[1]	Number of Filings
Aqua NC Flushing Plan	Sub 497, OP 18	June 2019	1
Aqua NC Report of Specific Benefits of AMR Technology	Sub 497, OP 27	June 2019	1
Bi-Monthly Report on Secondary Water Quality Issues[1]	Sub 497, OP 9	January 2020	4
Application for Approval to Implement Secondary Water Quality System Improvement Projects[3]	N.C.G.S. § 62-133.12 and Commission Rule R7 -39	December 2014	12
WSIC/SSIC Annual Report and Calculations[3]	N.C.G.S. § 62-133.12 and Commission Rules R7-39(j) and (l) and R10-26(j) and (l)	February 2016	5

Witness Becker divided the reporting requirements into two groups: (1) pre- Sub 497 requirements and (2) requirements established in the Sub 497 Order. He testified that some of the reports are no longer relevant because the underlying issues either have been resolved or are well on the way to management and improvement and that the costs of preparation of these reports are significant to the Company. Witness Becker testified that the Company expended 588 work hours to file nine of the new reports established in the Sub 497 Order. According to his testimony, these 588 hours are in addition to the time required to comply with the Company's other filing and reporting obligations. *Id.* at 130-31.

Witness Becker asked the Commission to revisit Aqua NC's reporting requirements and modify them "given recent measurable progress plus the cost/benefit ratio of their continuance at the current level." *Id.* at 144. Witness Becker testified that some of the requirements should be revised, reduced, or restructured because the underlying circumstances supporting the need for the reports have changed and conditions have improved over time. *Id.* at 130-31. Witness Becker testified that (1) Aqua NC supports reporting requirements that are relevant and useful to the Commission as it carries out its oversight mission and (2) Aqua NC is interested in participating in discussions to "assess whether the current reporting requirements should be revised." *Id.* at 131.

Witness Becker elaborated on his views on reporting requirements with some level of specificity while responding to questions from Commissioner McKissick during the evidentiary hearing. He indicated that Aqua NC lacks a clear understanding of the information the Commission is interested in receiving and is concerned that the information the Commission receives is repetitive. Witness Becker outlined three changes that he deems appropriate: (1) eliminating reporting requirements for water systems that presently have "very reduced water quality complaints"; (2) modifying the thresholds used to determine whether Aqua NC must include a water

[1] Not included in witness Becker's prefiled direct testimony.

system in its reports; and (3) lengthening the reporting interval so that reports are due annually, rather than semiannually. Tr. vol. 3, 76-77.

Public Staff Witness Franklin

The Public Staff's views on Aqua NC's reporting requirements were presented by witness D. Michael Franklin. His testimony touched on six topics: (1) the Company's request to discontinue bi-monthly reporting on 16 of the 18 water systems about which customers complained in earlier rate cases, (2) the appropriateness and reasonableness of the thresholds used to determine whether Aqua NC must prepare and submit bi-monthly reports about the water quality in an individual water system, (3) the frequency with which Aqua NC must submit written water quality reports about water systems for which bi-monthly reporting is no longer required, (4) reporting oral communications between Aqua NC and DEQ, (5) the requirement that Aqua NC provide copies of select documents exchanged with DEQ, and (6) the parties' differing interpretations of the requirements of Paragraph 14 of the Sub 497 Order.

Witness Franklin testified that the Public Staff agreed with Aqua NC's request to discontinue bi-monthly reporting required by Ordering Paragraph 8 of the Sub 363 Order and Ordering Paragraph 9 of the Sub 497 Order for the following water systems: Meadow Ridge, Olde South Trace, Sedgemoor Village of Wynchester, Westmoor, Stonebridge, Sussex Acres, Swans Mill, Wood Valley, Castelli, High Grove, Medfield, Saddleridge, Upchurch Place, Waterfall Plantation, and Yorkwood Park. However, witness Franklin testified that the Public Staff does not support Aqua NC's request to discontinue bi-monthly reporting on the Coachman's Trail system because the system "continues to experience operational and equipment issues directly affecting water quality." Tr. vol. 8, 86-87.

Witness Franklin addressed the thresholds used to determine whether Aqua NC must prepare and submit bi-monthly reports about the water quality in an individual water system in his testimony. Ordering Paragraph 11 in the Sub 363 Order established the thresholds as follows: semiannually written reporting is required if a particular secondary water quality concern has affected or is affecting 10 percent of the customers in an individual subdivision service area or 25 billing customers, whichever is less. This requirement was continued under the terms of Ordering Paragraph 10 of the Sub 497 Order and witness Franklin recommended that it remain in place going forward. *Id.* at 95. Witness Franklin testified that "the current threshold of 10 percent or 25 billing customers is appropriate and reasonable because it ensures secondary water quality concerns affecting both large and small utility systems are properly identified." *Id.* at 100.

Witness Franklin also provided testimony about the frequency with which Aqua NC must provide the semiannual report concerning secondary water quality concerns. Aqua NC requested that the interval between submission of its written reports for those water systems be lengthened from semiannual reporting to annual reporting. Witness Franklin testified that "the semiannual frequency is also appropriate and reasonable because it provides sufficient time for data collection and the timely development of corrective actions to address the issues identified." *Id.* Witness Franklin elaborated during his examination by Commissioner Brown-Bland stating "we believe the annual time frame is too long and it doesn't allow enough time for the Public Staff to reach out while the information is still fresh to customers." *Id.* at 112.

Witness Franklin's testimony included a discussion of the two reporting requirements related to Aqua NC's communications with DEQ. Ordering Paragraph 14 in the Sub 497 Order requires Aqua NC to provide the Public Staff with written summaries of all meetings and conversations with, reports to, and the recommendations of DEQ regarding the water quality concerns being evaluated and addressed in Aqua NC's systems. Witness Franklin initially recommended continuing this requirement, but he changed his recommendation based upon Aqua NC's assertions that its communications with DEQ have been negatively impacted by those reporting obligations. *Id.* at 102. Aqua NC witnesses Becker and Berger both testified that the reporting requirements are burdensome and cumbersome and, as such, Aqua NC's oral exchanges with DEQ have declined significantly. Witness Franklin testified that the Public Staff has changed its recommendation because it "does not want to suppress communications between Aqua NC and DEQ . . . with the understanding that written communications will continue and be provided to the Public Staff." *Id.* Witness Franklin explained that the Public Staff is now recommending that written summaries of Aqua NC's oral communications with DEQ are no longer required, but the Public Staff's position assumes that Aqua NC will not materially alter the way in which it communicates with DEQ such that most communications are oral, rather than written. *Id.* at 103.

While Public Staff witness Franklin indicated that the Public Staff was recommending a that the Commission forego the reporting requirement related to oral exchanges with DEQ, he testified that the Public Staff was recommending that the Commission continue the requirement that Aqua NC provide the Public Staff with copies of its written correspondence with DEQ. *Id.* at 95. As such, witness Franklin recommended that Aqua NC continue to provide the Public Staff with copies of:(1) Aqua NC's reports and letters to DEQ concerning water quality in its systems; (2) responses from DEQ concerning reports, letters, or other oral or written communications; and (3) DEQ's specific recommendations to Aqua NC, by system, concerning each of the water quality concerns being evaluated by DEQ. *Id.* This requirement was originally instituted by Ordering Paragraph 12 in the Sub 363 Order and was extended in Ordering Paragraph 14 of the Sub 497 Order.

Witness Franklin explained the Public Staff's interpretation of the requirements of Ordering Paragraph 14 in the Sub 497 Order on cross-examination. He stated that the "Public Staff views Ordering Paragraph 14 to be specifically related to all water quality issues, with the exception of paragraph (d)," which is restricted to secondary water quality issues. *Id.* at 106.

Aqua NC Witness Berger Rebuttal

Witness Berger testified on rebuttal that the Company recognizes that some level of reporting to the Commission on secondary water quality concerns may be desired and warranted and recommended that in lieu of the current bi-monthly and semiannual reporting, that the Commission establish an Annual Secondary Water Quality Report to be filed by March 31st of each year. She suggested the annual report provide an accounting of the progress made in the previous calendar year and include a summary of systems that experienced secondary water quality concerns that have affected 10 percent of the customers in an individual subdivision area or 25 billing customers in an individual service area, whichever is less, in a semiannual period; a secondary water quality data update on the number of entry points that have consistent water quality results greater than factors for Group 1with a status of each system; a secondary water quality project update that provides an update on filter projects; and Executive Summary updates from the WSIC/SSIC docket. *Id.* at 137-38.

Witness Berger testified that her recommendations align with other environmental regulatory reports and provide relevant information that can assist the Commission and Aqua's customers in assessing the Company's progress toward correcting secondary water quality concerns. She also recommended that the Commission stop its requirement that the Company provide DEQ communications for primary and secondary water quality concerns beyond the Company's NOD responses stating that Aqua NC does not have a poor compliance track record with its environmental regulators and asserting that the Public Staff did not present adequate justification in support of its proposal for a continued reporting requirement. *Id.* at 138.

Witness Berger also testified about Aqua NC's understanding of Ordering Paragraph 14 in the Sub 497 Order. She explained that based on the Findings of Fact, and the summary paragraphs related to Ordering Paragraphs 11 through 14, Aqua NC interprets the reporting requirements to relate only to secondary water quality issues. *Id.* at 144.

Additionally, witness Berger testified that the Company should not be required to report on primary water quality issues because Aqua's primary drinking water standards for the past three years were 0.7% while the national average of non-compliant public water systems was 38% and the average of non-compliant public water systems across the state was 33% for the same time period. She stated that Aqua NC is concerned that the Public Staff's reporting expectations and recommendations have become punitive versus productive given that the Company's primary drinking water compliance record is historically very good when compared across North Carolina systems and other similarly sized and regulated systems. She also stated that reporting requirements are extensive and expensive, and Aqua NC requests the Commission to carefully review the question of whether they are, as constituted, productive of information that is necessary to sound regulatory review, or whether they are unproductively excessive and can be modified or eliminated. *Id.* at 132-33.

Witness Berger also testified that secondary water quality issues are not an Aqua-only issue. Iron and manganese are found in amounts greater than the sMCLs (Fe> 0.3 mg/L, Mn>0.05 mg/L) in groundwater throughout the state. Witness Berger testified that despite Aqua NC's significant demonstrated improvement to address water quality issues through investment in filtration and operational attention, the resultant decline in water quality complaints, and its leading compliance record for primary contaminants, the Public Staff continues to recommend heightened reporting requirements. These reporting requirements for Aqua NC come at the cost of the Company staff's time and energy that could be re-allocated toward maintaining the historically good compliance record on primary drinking water standards and continuing significant improvement with regard to secondary water quality standards. *Id.* at 135-36. Additionally, witness Berger testified that reporting on both primary and secondary water quality issues would be extremely burdensome to the Company because of the level of detail required to track all communications throughout all locations among the 700 public water systems in North Carolina. *Id.* at 148-49. As a solution to reduce this burden, witness Berger suggested that provision of primary and secondary Notices of Violation and of Deficiency would meet the Commission's needs. *Id.* at 107.

Public Staff Witness Franklin Redirect

Witness Franklin testified on redirect examination that it was the Public Staff's position that the reporting requirements set out in subparagraphs (a) through (c) of Ordering Paragraph 14 of the Commission's Sub 497 apply to both primary and secondary water quality concerns. He testified that primary water concerns are addressed by regulatory limits on contaminants and could implicate health concerns. Witness Franklin further testified that, if Aqua NC does not have many primary water quality concerns, the reporting requirements associated with those concerns would not be onerous. *Id.* at 109.

When asked by Commissioner Brown-Bland why the Public Staff believed the semiannual reporting frequency should not be reduced to annual, witness Franklin testified that an annual reporting frequency could prevent the Public Staff from being able to contact customers regarding water quality issues until long after they have occurred and the details surrounding the issues may have been forgotten. To illustrate his point, witness Franklin noted that, pursuant to Aqua NC's recommended revision to the semiannual reporting requirement, a water quality issue experienced in January would not be reported on by the Company until March of the following year. In addition to the concern that the details of the issue would no longer be fresh in the customer's mind if the Public Staff were to follow-up on the issue, witness Franklin noted that the passage of time between the occurrence of an issue and Public Staff follow-up might give a customer the impression that their concern was not important to the Public Staff. *Id.* at 112.

Witness Berger Rebuttal Cross-Examination

On cross-examination on her rebuttal testimony, witness Berger testified that requiring the Company to report on both primary and secondary water concerns would be burdensome to the Company. She appeared to suggest that the Public Staff should instead obtain this information directly from DEQ. *Id.* at 151.

Discussion and Conclusions

The evidence of record establishes that the overall quality of water service provided by Aqua NC is adequate. While the volume of customer complaints regarding water quality and customer service issues was substantially reduced in this case as compared to the Sub 497 rate case, the Commission notes that the nature of the complaints was largely unchanged and customers testified that long standing secondary water quality and customer service issues had improved, they remain unresolved.

Having carefully evaluated the evidence, the Commission concludes that the bi-monthly reporting requirement should continue for the Coachman's Trail, Barton's Creek Bluffs, and Lake Ridge Aero Park subdivisions.

The Commission further concludes that the semiannual reporting requirement regarding water quality issues should not be altered at this time. These requirements should remain in place so long as the Company continues to experience water quality complaints akin to those raised in the Sub 363 and Sub 497 dockets, and in the present case. This conclusion is supported by evidence that reports of discolored water increased during the first quarter of 2020 as compared to the previous year. The Commission further concludes that lengthening the interval between reports would impair the Commission's oversight of Aqua NC and, as witness Franklin testified, the Public Staff's ability to serve the interests of the using and consuming public.

Regarding the reporting requirements set out in subparagraphs (a) through (c) of Ordering Paragraph 14 of the Sub 497 Order, the Commission concludes that these requirements apply solely to secondary water quality concerns. A review of the Sub 363 Rate Case Order reveals that, in reference to Ordering Paragraphs 8, 11, and 12, the term "water quality" was used approximately 52 times with each reference either specifically or by context referring to secondary water quality. A review of the Sub 497 Rate Case Order reveals that, in reference to Ordering Paragraphs 9, 10, and 14, the term "water quality" was used 57 times with all but two uses referencing, either specifically or by context, secondary water quality. Additionally, as noted by witness Berger in her testimony, Finding of Fact 34 and the supporting discussion regarding reporting requirements within the text of the Sub 497 Order are clear that the term "water quality" relates solely to secondary water quality. The same is true for the Findings of Fact and the supporting discussion regarding the reporting requirements within the text of the Sub 363 Order. The Public Staff's assertion otherwise is simply not supported by the language contained in either the Sub 363 or Sub 497 Order. Accordingly, the Commission concludes that Aqua NC's reporting requirements as previously elucidated in Ordering Paragraph 14 of the Sub 497 Order shall apply only to secondary water quality issues and additionally, shall from this point forward, only apply to written reports to DEQ; written communications between Aqua NC and DEQ; and the recommendations of DEQ regarding secondary water quality concerns, being evaluated and addressed in Aqua NC's systems. Oral communications shall no longer be subject to the reporting requirements discussed in this Order or previously required under the Sub 497 Order.

Aqua NC shall henceforth provide the Public Staff copies of: (a) Aqua NC's reports and letters to DEQ concerning secondary water quality concerns in its systems; (b) responses from DEQ concerning reports, letters, or other written communication received from Aqua NC concerning secondary water quality concerns in its systems; and (c) DEQ's specific recommendations to Aqua NC, by system, concerning each of the secondary water quality concerns being evaluated by DEQ.

In reaching these conclusions, the Commission recognizes that the Public Staff has an obligation to ensure the using and consuming public is properly represented not only in rate cases but also in between rate case proceedings. The Commission greatly appreciates the care the Public Staff takes to ensure consumers are treated fairly. The Commission also recognizes that the Public Staff must have access to sufficient and relevant data and documentation to uphold its duty to fully analyze a utility's sound and prudent management. Additionally, the time and effort required to comply with reporting requirements and the usefulness of the information are also relevant concerns and should be considered when formulating reporting requirements. The Commission notes that the amount of staff time and effort required to satisfy reporting requirements going forward should be appreciably less than the staff time and effort required to satisfy the filing and reporting requirements ordered in the Sub 497 Order for several reasons. First, Ordering Paragraphs 15, 16, 17, 18, 20, 24, and 25 required one-time or non-recurring filings, and Aqua NC has fully complied with the requirements set forth in those paragraphs. Second, the reporting requirements of Ordering Paragraph 14 of the Sub 497 rate case order have been clarified to relate only to secondary water quality issues. Third, Aqua NC will no longer be required to provide notification of oral communications with DEQ to the Public Staff. Finally, the Commission finds that it is appropriate to eliminate 15 of 16 previously required bi-monthly reports from existing requirements.

Regarding the provision of AMR meter data to customers, the Commission notes that its determination in the Sub 497 Order that it was appropriate to include Aqua NC's investment in AMR technology in rates was premised in part on the Commission's finding that the functionalities of AMR technology were being utilized to the benefit of ratepayers and benefits would incrementally increase to ratepayers as Aqua NC fully deployed the technology. As such, the Commission concludes that the Company shall, upon the filing of this Order, share the 40-day meter read history collected by its AMR technology with its AMR-metered customers upon request. Furthermore, in its effort to stay apprised of the development of customers' access to AMR data, the Commission concludes that the Company shall file its Strategic Plan for Meter Data Management and Advanced Analytics referred to in the Company's filings in accordance with Ordering Paragraph 27 in Docket No. W-218, Sub 497A.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation between Aqua NC and Public Staff is hereby approved in its entirety;

2. That all of the findings, conclusions, and decisions reflected in this Order are hereby affirmed and are so ordered for compliance purposes;

3. That the Schedules of Rates, attached hereto as Appendices A-1, A-2, A-3, and A-4, are hereby approved and deemed to be filed with the Commission pursuant to N.C.G.S. § 62-138;

4. That the attached Schedules of Rates are hereby authorized to become effective for service rendered on and after the issuance date of this Order;

5. That the Notices to Customers, attached hereto as Appendices B-1, B-2, and B-3 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;

6. That Aqua NC shall file the attached Certificate of Service, properly signed and notarized, not later than 45 days after the issuance of this Order;

7. That the Commission considers neither the Partial Settlement Agreement and Stipulation filed on July 1, 2020, nor the parts of this Order pertaining to the contents thereof, as having precedential value with respect to future proceedings and the same shall not be cited, argued, or treated as such;

8. That all late-filed exhibits filed by Aqua NC and the Public Staff in this docket are hereby admitted in evidence;

9. That the Chief Clerk shall establish Docket No. W-218, Sub 526A as the reporting requirement docket for Commission-required reports as ordered herein and also for WSIC/SSIC filings;

10. That Aqua NC shall file a copy of its updated AFUDC policy in Docket No. W-218, Sub 526 within 60 days of the issuance date of this Order;

11. That Aqua NC shall conduct a comprehensive review of its current procedures and policies for determining when projects are complete, in-service, and booked to plant in service and file the Company's findings with respect to its internal accounting practices and policies and any plans or recommendations regarding changes in those procedures and policies within 90 days of the issuance date of this Order. Aqua NC shall consult with the Public Staff regarding the findings of its review and shall work collaboratively with the Public Staff regarding changes in those procedures and policies;

12. That Aqua NC should file annual reports described herein concerning the effect of the implementation of metered sewer rates on the monthly bills of residential customers in the Aqua NC Sewer and Fairways Sewer Rate Divisions with the Commission within 45 days after the calendar year ends, beginning with the calendar year ending December 31, 2021;

13. That Aqua NC shall compile monthly consumption data of customer accounts by blocks of per 1,000 gallons to properly design and evaluate a tiered inclining block rate structure;

14. That Aqua NC shall file quarterly reports with the Commission on its Conservation Pilot Program that, at a minimum, include monthly historical and current consumption by blocks of 1,000 gallons and the corresponding number of bills and revenues for each customer group, and such reports shall be filed within 30 days of the end of each calendar quarter, beginning with the quarter ending March 31, 2021. The semiannual reconciliation report on the Conservation Pilot Program indicating the amount to date of any surcharge or surcredit to customers shall be filed within 30 days of the reporting period, beginning with the reporting period ending June 30, 2021;

15. That the annual revenue reconciliation request by Aqua NC and the supporting calculation and data for an annual adjustment shall be filed with the Commission at least 45 days prior to the annual adjustment effective date;

16. That Aqua NC and the Public Staff shall develop a mutually-agreeable purchased water loss standard based upon the methodology for purchased water systems set forth in Aqua NC's Pearce and Kunkle rebuttal testimony for implementation in the Company's next general rate case and report on the progress of those discussions to the Commission within nine months of this Order;

17. That Aqua NC shall continue to file bi-monthly reports addressing secondary water quality concerns raised by customers in the Coachman's Trail, Barton's Creek Bluffs, and Lake Ridge Aero Park subdivisions in situations where the iron and manganese concerns remain pending further Order of the Commission. Such reports shall describe measures taken by Aqua NC to address water quality issues and shall include summaries of customer concerns raised,

results of water laboratory analyses (including soluble and insoluble concentration levels of iron and manganese) to measure baseline concentration levels and the effectiveness of chemical sequestration treatment, flushing regimens, and cost estimates to install filtration systems (greensand or other filtration options deemed appropriate) or to procure alternate water sources;

18. That Aqua NC and the Public Staff shall continue to work together regarding the development of appropriate recommendations and solutions to improve secondary water quality as impacted by the levels of iron and manganese at the Company's affected water systems;

19. That the Public Staff and Aqua NC are required to file a written report with the Commission, on March 1 and September 1 each year in which the WSIC is in effect, on secondary quality concerns that are affecting its customers. If a particular secondary water quality concern has affected or is affecting 10% of the customers in an individual subdivision service area or 25 billing customers in an individual service area, whichever is less, the customers affected and the estimated expenditures that are necessary to eradicate to the extent practicable water quality issues related to iron and manganese through the use of projects that are eligible for recovery through the WSIC shall be detailed in the written report. The written report shall also contain a recommendation as to whether the Commission should order Aqua NC to pursue such corrective action and an underlying reason why the action should or should not be undertaken. If there are no secondary water issues or if the secondary water quality issues are below the 10%/25 threshold previously set forth, Aqua NC and the Public Staff shall so inform the Commission, but they need not report secondary water quality issues resolved by Aqua NC without the assistance or expectation of assistance of the WSIC;

20. That Aqua NC shall also continue to file its annual Three-Year WSIC and SSIC Plan, as well as its Quarterly Earnings, WSIC/SSIC Revenues, and Construction Status reports, its Annual Heater Acquisition Incentive Account Report, the DEQ Quarterly Notice of Deficiency filings, and the DEQ Secondary Water Quality Filtration Request Executive Summary;

21. That Aqua NC shall continue to promptly provide to and share with the Public Staff written reports to DEQ, written communication between Aqua NC and DEQ; and the written recommendations of DEQ regarding secondary water quality concerns being evaluated and addressed in Aqua NC's systems. Such communication to the Public Staff shall not be considered or treated as a formal report authored by Aqua NC, but rather as notification of the occurrence of written communications between the Company and DEQ and shall continue to contain a description of the salient topic and content points, shall be in a written format and shall be provided, at a minimum, on a bi-monthly basis until otherwise ordered by the Commission. Without limitation on the foregoing, Aqua NC shall provide the Public Staff copies of: (a) Aqua NC's reports and letters to DEQ concerning secondary water quality concerns in its systems; (b) written responses from DEQ concerning reports, letters, or other written communication received from Aqua NC concerning secondary water quality issues; (c) DEQ's specific written recommendations to Aqua NC, by system, concerning each of the secondary water quality concerns being evaluated by DEQ; and (d) written communications from DEQ to Aqua NC indicating DEQ's dissatisfaction with Aqua NC's response to DEQ's concerns, directions or recommendations concerning water quality affected by iron and manganese;

22. That Aqua NC shall strive to return to its pre-COVID-19 level of flushing activities as soon as reasonably possible to improve water quality for its customers experiencing secondary water quality issues; that Aqua NC's general flushing plan filed on June 17, 2019, in Docket No W-218, Sub 497, shall be subordinate to the manufacturer's recommended flushing schedule whenever a sequestering agent, including SeaQuest® is introduced into a Company water system. Aqua NC shall follow the manufacturer's recommended flushing schedule, and any time Aqua NC does not follow the manufacturer's recommendation, the Company shall make a filing with the Commission if the recommended flushing does not occur within 60 days of the recommended time for flushing; such filing shall be made within 60 days of departing from the original recommended schedule, explaining the reasons the flushing schedule could not be followed;

23. That at any time after a year from the issuance of this Order, Aqua NC may request that the Commission revise or eliminate the regular and periodic reporting requirements ordered herein due to demonstrated and significant progress in customer satisfaction with improvements made in water quality related to levels of iron and manganese;

24. That Aqua NC shall take the appropriate measures to share the 40-day meter read history collected by the Company's AMR technology with the AMR-metered customers upon request and shall track when such information is being shared, including how such information is being provided to customers. This tracked information should be made available in a timely manner at the request of either the Commission or the Public Staff;

25. That, upon its completion, Aqua NC shall file with the Commission the Strategic Plan for Meter Data Management and Advanced Analytics;

26. That Aqua NC shall refund all partial, temporary rates and charges in excess of the final rates and charges found to be appropriate by the Commission, if any, in the Aqua NC Water, Aqua NC Sewer, and Brookwood Water Rate Divisions with interest at 10% compounded annually;

27. That Aqua NC shall file a refund plan for the excess partial, temporary rates and charges collected from the customers, if any, in the Aqua NC Water, Aqua NC Sewer, and Brookwood Water Rate Divisions within 30 days of the date of this Order and the Public Staff shall file a response to said refund plan no later than 60 days from the date of this Order; and

28. That the Chief Clerk shall close Docket No. W-218, Sub 497A.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of October, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

Commissioner Kimberly W. Duffley did not participate in this decision.
Commissioner Daniel G. Clodfelter concurring in part and dissenting in part.

WATER AND SEWER – RATE INCREASE

DOCKET NO. W-218, SUB 497

Commissioner Daniel G. Clodfelter, concurring in part and dissenting in part:

I join in the Commission's decision and opinion as to all save one group of issues, and to those items only I dissent. In Findings of Fact 9, 11, and 22, the Commission determines that the Stipulation between the Company and the Public Staff is just and reasonable and should be accepted in its entirety. Public Staff witness Feasel in her original prefiled testimony proposed disallowing 50% of the total compensation of the Company's top five executives, 50% of the expenses of the Aqua America board of directors allocated to North Carolina, 50% of the stock options allocated to the Company's North Carolina employees, and that portion of employee bonuses that is tied to an increase in earnings per share for the Company's ultimate parent entity. (The details of these items are discussed in the Commission's opinion at pages 50 through 56.) In paragraphs LL and MM of the proposed Stipulation the Public Staff has now abandoned these positions. For the same reasons set forth in my dissenting opinion in the Sub 497 Rate Case Order, believe the Public Staff's original position is the better and more persuasive one as a matter of sound policy, and I would therefore decline to accept the proposed Stipulation to the extent, but only to the extent, it withdraws these proposed adjustments and allows full recovery of these expenses from the Company's ratepayers.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

WATER AND SEWER – RATE INCREASE

SCHEDULE OF RATES

for

AQUA NORTH CAROLINA, INC.

for providing water and sewer utility service in

ALL ITS SERVICE AREAS IN NORTH CAROLINA AND THE EMERGENCY OPERATION OF MOBILE HILL ESTATES

WATER UTILITY SERVICE

► *All Aqua NC systems except as noted below*

Monthly Metered Service (residential and commercial customers):

Base facility charge (zero usage, based on meter size)

<1" meter	$ 20.70
1" meter	$ 51.75
1½" meter	$ 103.50
2" meter	$ 165.60
3" meter	$ 310.50
4" meter	$ 517.50
6" meter	$1,035.00

Usage charge, per 1,000 gallons $ 6.38
All service areas unless noted differently below

For bulk purchased water system usage charges see attached Appendix A-2

Conservation Pilot Program
Arbor Run, Bayleaf, Merion and Pebble Bay Subdivisions

Tiered usage charge, per 1,000 gallons (residential)

1 - 4,000 gallons	$ 4.14
4,001 - 8,000 gallons	$ 6.21
8,001 - 15,000 gallons	$ 9.32
15,001+ gallons	$ 12.42

Tiered usage charge, per 1,000 gallons (irrigation meters)

1 - 15,000 gallons	$ 9.32
15,001+ gallons	$ 12.42

Monthly Unmetered Service (flat rate): 1/

Residential customers	$ 46.22
Commercial customers, per residential equivalent unit (REU)	$ 73.63

▶ *Brookwood and LaGrange Service Areas Cumberland and Hoke Counties*

Monthly Metered Service (residential and commercial customers):

Base facility charge (zero usage, based on meter size)

<1" meter	$ 16.01
1" meter	$ 40.03
1½" meter	$ 80.05
2" meter	$ 128.08
3" meter	$ 240.15
4" meter	$ 400.25
6" meter	$ 800.50

Usage charge, per 1,000 gallons $ 4.57

For bulk purchased water system usage charges see attached Appendix A-2

Monthly Unmetered Service (flat rate): 1/

Residential customers	$ 37.24
Commercial customers (per REU)	$ 52.56

▶ *Fairways and Beau Rivage Service Area – New Hanover County*

Monthly Metered Service (residential and commercial customers):

Base facility charge (zero usage, based on meter size)

<1" meter	$ 8.56
1" meter	$ 21.40
1½" meter	$ 42.80
2" meter	$ 68.48
3" meter	$ 128.40
4" meter	$ 214.00
6" meter	$ 428.00

Usage charge, per 1,000 gallons $ 1.55

Monthly Unmetered Service (flat rate): [1/]

Residential customers	$ 17.91
Commercial customers (per REU)	$ 23.61

OTHER MATTERS

Specific Service Area Connection Charges and Capacity Fees: [2/]
(see attached Appendix A-3)

Connection Fee in All Other Service Areas: [2/]

<1" meter	
For taps made to existing mains installed inside franchised service area	$800.00
For individual connections installed outside franchised service area[3/]	Actual cost of installation [4/]
1" meter or larger	120% of actual cost of making tap, including setting meter and box

Water Capacity Fee per GPD – Flowers Plantation Development (Buffalo Creek and Neuse Colony):
(See Docket No. W-218, Sub 526)

Water capacity fee per GPD	$ 6.25

The bulk water capacity fee was changed by Johnston County, effective October 1, 2020. Such rates per GPD are subject to change based on future schedules of rates and fees issued by Johnston County.

Meter Installation Fee: $70.00
(The fee will be charged only where cost of meter installation is not otherwise recovered through connection charges.)

Production and Storage Contribution in Aid of Construction Fee: [3/]

For individual connections outside franchised service areas where lot owner has made no contribution in aid of construction toward production and storage facilities	$1,700 per residential equivalent unit (REU)

Reconnection Charges: [5/]

If water service cut off by utility for good cause	$35.00
If water service discontinued at customer's request	$15.00

Billing Service Charge: [6/] $2.00 per month per bill

New Customer Account Fee: $20.00
(If customer receives both water and sewer utility service from Aqua NC, then the customer shall only be charged a new account fee for water.)

SEWER UTILITY SERVICE

▶*All Aqua systems except as noted below*

Monthly Unmetered Service (flat rate):

Residential customers	$ 75.38
Commercial customers (per REU)	$ 105.53

STEP system flat rate (Monticello, Holly Brook, Saddleridge) $ 32.00

Monthly Metered Service (residential and commercial customers):

Base facility charge (zero usage, based on meter size)

<1" meter	$ 60.43
1" meter	$ 151.08
1½" meter	$ 302.15
2" meter	$ 483.44
3" meter	$ 906.45
4" meter	$1,510.75
6" meter	$3,021.50

Usage charge, per 1,000 gallons $ 2.99

For bulk purchased sewer system charges see attached Appendix A-2

Carolina Meadows, Inc. will be charged 50% of the sum of all contributory water meter base facility charges, which is currently 186 REUs or 50% of 372 REUs.

► *Fairways and Beau Rivage Service Area – New Hanover County*

Monthly Unmetered Service (flat rate):

Residential customers	$ 54.11
Commercial customers (per REU)	$ 73.25

Monthly Metered Service (residential and commercial customers):

Base facility charge (zero usage, based on meter size)

<1" meter	$ 46.49
1" meter	$ 116.23
1½" meter	$ 232.45
2" meter	$ 371.92
3" meter	$ 697.35
4" meter	$1,162.25
6" meter	$2,324.50

Usage charge, per 1,000 gallons $ 1.83

OTHER MATTERS

Specific Service Area Connection Charges and Capacity Fees: [2/]
(See attached Appendix A-3)

Connection Fee in All Other Service Areas:

None when tap and service line installed by developer.

Actual Cost if Aqua NC makes tap or installs service line.

Sewer Plant Capacity Fee per GPD (DEQ Design Requirements) – River Park Development:

Sewer Plant Capacity Fee per GPD $ 10.00
(See Docket No. W-218, Sub 143)

Wastewater Capacity Fee per GPD – Flowers Plantation Development (Buffalo Creek):
(See Docket No. W-218, Sub 526)

Wastewater capacity fee per GPD	$ 11.00
(Combined transmission and treatment capacity fee)	

The bulk wastewater capacity fee was changed by Johnston County, effective July 1, 2020. Such rates per GPD are subject to change based on future schedules of rates and fees issued by Johnston County.

Sewer Plant Capacity Fee per GPD – Flowers Plantation Development (Neuse Colony):
(See Docket No. W-218, Subs 497 and 520)

Sewer plant capacity fee per GPD	$ 9.47

The sewer plant capacity fee may change in the future as a result of additional improvements or further expansion by Aqua NC to the Neuse Colony wastewater treatment plant.

Developer Contribution to Aqua NC – 50% Aqua NC's Cost of Buffalo Creek Pump Station and Force Main – Flowers Plantation Development (Buffalo Creek):
(See Docket No. W-218, Sub 497)

Pursuant to Amended Purchase Agreement dated May 14, 2002, between River Dell Utilities, Inc., Rebecca Flowers Finch (d/b/a River Dell Company), and Heater Utilities, Inc. (See Docket No. W-274, Sub 538 and Docket No. W-218, Sub 497)

$440,816 divided equally among the first 2,000 single-family residential equivalents (SFREs) or $220.41 per SFRE

Reconnection Charges: [5/]

If sewer service cut off by utility for good cause	Actual Cost

Grease Traps:

The Utility may require installation and/or proper operation of grease traps on grease producing commercial facilities. Failure to properly operate grease traps will result in disconnection of service pursuant to Commission Rule R10-16.

New Customer Account Fee:	$ 20.00

(If customer receives both water and sewer utility service from Aqua NC, then the customer shall only be charged a new account fee for water.)

Grinder Pump Installation Fee – Governors Club Subdivision: Actual Cost
(See Docket No. W-218, Sub 277)

The homeowner or house builder shall be required to prepay in full to the outside contractor installing the grinder pump the entire cost of the installation, including the applicable engineering inspection fee, as specified in Aqua NC's Grinder Pump Installation In-house Procedures, a copy of which is filed with the Commission.

Once the grinder pump is initially installed, it will be the responsibility of Aqua NC to maintain, repair, and replace the grinder pump. However, if damage to a grinder pump is shown to be due to homeowner negligence, the homeowner will be liable for the cost of the repair or replacement of the grinder pump.

Returned Check Charge:	$25.00
Bills Due:	On billing date
Billing Frequency:	Monthly for service in arrears
Bills Past Due:	15 days after billing date
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

Availability Rates:

Woodlake Subdivision:

Water	$5.00 per month
Sewer	$3.75 per month

Governors Village Subdivision, Governors Forest Subdivision, Governors Village Townhomes:

Sewer only	$12.50 per month

Governors Club:

Sewer only	$20.00 per month

Notes:

1/ The Utility, at its expense, may install a meter and charge the metered rate.

2/ In most areas, connection charges do not apply pursuant to contract and only the $70.00 meter installation fee will be charged to the first person requesting service (generally the builder). Where Aqua NC must make a tap to an existing main, the charge will be $800.00, and where main extension is required, the charge will be 120% of the actual cost.

3/ Individual connections outside franchised service areas may be made pursuant to this tariff in the following circumstances: (1) upon request of a bona fide customer as that term is defined in Commission Rule R7-16(a)(1); (2) the customer shall be located either within 100 ft. of a Franchised Service Area or located within 100 ft. of an existing Aqua NC main; and (3) the request may come from no more than two customers located in the same area (requests for more than two connections require an application for a new franchise or a request for approval of a contiguous extension). To connect such a customer, Aqua NC shall file a notice with the Commission in Docket No. W-218, Sub 177, at least 30 days before it intends to make the tap. This notice shall include an explanation of the circumstances requiring the tap and an 8.5" x 11" map showing the location of the tap in relation to Aqua NC's existing main. If the Public Staff does not object to the tap within the 30-day period, or upon written notice within that period from the Public Staff that it will not object, Aqua NC may proceed with the connection.

4/ Actual cost for such a connection shall include installation of a 6" or smaller main extension (if necessary), tap of the main, service line, road bore (if necessary), meter box, meter, backflow preventer (if necessary), and Aqua NC's direct labor costs. Aqua NC shall give a written cost quote to the customer(s) applying for connection before actually beginning the installation work.

5/ When service is disconnected and reconnected by the same unit owner within a period of less than nine months, the entire flat rate and/or base charge rate will be due and payable before the service will be reconnected.

If sewer disconnection is required, after all reasonable efforts by the Utility to encourage the customer to comply with the provisions of the tariff have been made, the Utility may install a valve or other device appropriate to cut off or block the customer sewer line.

Prior to disconnection, the Utility shall give the customer written notice at least seven days prior to disconnection. Said notice shall include, at the minimum, a copy of this reconnect provision, the estimated cost to make the cut off, and install the valve or other device.

In the event that an emergency or dangerous condition is found or fraudulent use is detected, sewer service may be cut off without notice. In such an event, notice as described above, will be given as soon as possible.

Upon payment of outstanding balance, actual cost of termination and reconnection and other fees (for example, deposit if required by the Utility), the Utility shall restore the service no later than the next business day.

6/ Aqua NC is authorized to include on its monthly water bill the charges resulting from sewer service provided by the Town of Cary, the Town of Fuquay-Varina, Wake County, and various Commission appointed emergency operators where specifically approved by the Commission. Aqua NC will bill the Town of Cary, the Town of Fuquay-Varina, Wake County, or appointed emergency operator $2.00 per month per bill for providing this service.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-218, Sub 526, on this the 26th day of October, 2020.

AQUA NORTH CAROLINA, INC.
BULK PURCHASED WATER SYSTEM USAGE RATES

Usage charge, per 1,000 gallons where water purchased for resale

Service Area	Water Provider	Usage Charge/ 1,000 gallons
Aqua North Carolina Service Areas		
Twin Creeks	City of Asheville	$ 4.96
Heather Glen and Highland	City of Belmont	$14.40
Southpoint Landing	City of Belmont	$14.40
Park South	City of Charlotte	$ 2.19
Parkway Crossing	City of Charlotte	$ 2.19
Springhill / Springdale	City of Concord	$ 5.42
Hoopers Valley	City of Hendersonville	$ 3.47
Crystal Creek	City of Hendersonville	$ 3.47
Rambling Ridge	City of Hendersonville	$ 3.47
Brookwood	City of Hickory (outside city)	$ 3.25
Heritage Farms	City of Hickory (inside city)	$ 3.25
Cedarwood Estates	City of Hickory (inside city)	$ 3.25
Hill-N-Dale	City of Lincolnton	$ 9.21
East Shores	City of Morganton	$ 2.51
Greenfield	City of Mount Airy	$ 6.69
Bett's Brook	City of Newton	$ 3.29
Crestwood	Davidson Water, Inc.	$ 4.76
Lancer Acres	Davidson Water, Inc.	$ 4.76
Beard Acres	Davidson Water, Inc.	$ 4.76
Woodlake Development	Harnett County	$ 2.78
Beechwood Cove	Chatham County	$ 7.04
Chatham	Chatham County	$ 7.04
Cole Park Plaza Shopping Center	Chatham County	$ 9.98
Hidden Valley	Chatham County	$ 7.04
Polks Landing	Chatham County	$ 7.04
Chapel Ridge	Town of Pittsboro	$13.69
Laurel Ridge	Town of Pittsboro	$13.69

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Service Area	Water Provider	Usage Charge/ 1,000 gallons
The Parks at Meadowview	Town of Pittsboro	$13.69
River Hill Heights	Iredell Water Corp.	$ 3.61
Bedford at Flowers Plantation	Johnston County	$ 2.66
Bennett Place	Johnston County	$ 2.66
Chatham	Johnston County	$ 2.66
Cottages at Evergreen	Johnston County	$ 2.66
Cottonfield Village	Johnston County	$ 2.66
Creekside Place	Johnston County	$ 2.66
Eastlake at Flowers Plantation	Johnston County	$ 2.66
Evergreen	Johnston County	$ 2.66
Flowers Crest	Johnston County	$ 2.66
Flowers Shopping Center	Johnston County	$ 2.66
Forge Creek	Johnston County	$ 2.66
Longleaf	Johnston County	$ 2.66
Magnolia	Johnston County	$ 2.66
Magnolia Place/Village	Johnston County	$ 2.66
Mill Creek North	Johnston County	$ 2.66
Mill Creek West	Johnston County	$ 2.66
Neuse Colony	Johnston County	$ 2.66
North Farm	Johnston County	$ 2.66
North Farm Cottages	Johnston County	$ 2.66
North Village	Johnston County	$ 2.66
Parkway Center/Village	Johnston County	$ 2.66
Peachtree	Johnston County	$ 2.66
Pineville Club	Johnston County	$ 2.66
Pineville East	Johnston County	$ 2.66
Pineville East Cottages/Palmetto Pl.	Johnston County	$ 2.66
Pineville East Estates	Johnston County	$ 2.66
Pineville West	Johnston County	$ 2.66
Plantation Park	Johnston County	$ 2.66
Plantation Pointe	Johnston County	$ 2.66
Poplar Woods	Johnston County	$ 2.66
River Dell East	Johnston County	$ 2.66

WATER AND SEWER – RATE INCREASE

APPENDIX A-2
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Service Area	Water Provider	Usage Charge/ 1,000 gallons
River Dell Townes	Johnston County	$ 2.66
Riverdell Elementary School	Johnston County	$ 2.66
Ross Landing	Johnston County	$ 2.66
South Plantation	Johnston County	$ 2.66
South Quarter	Johnston County	$ 2.66
Southgate	Johnston County	$ 2.66
Summerset Place	Johnston County	$ 2.66
Sun Ridge Farms	Johnston County	$ 2.66
Sweetgrass	Johnston County	$ 2.66
The Gardens at Flowers Plantation	Johnston County	$ 2.66
The Meadows	Johnston County	$ 2.66
The Nine	Johnston County	$ 2.66
The Woodlands	Johnston County	$ 2.66
Trillium	Johnston County	$ 2.66
Village at Flowers Plantation	Johnston County	$ 2.66
Walker Woods	Johnston County	$ 2.66
Watson's Mill	Johnston County	$ 2.66
West Ashley	Johnston County	$ 2.66
Whitfield at Flowers Plantation	Johnston County	$ 2.66
Wilders Woods and Extension	Johnston County	$ 2.66
Holly Hills	Town of Forest City	$ 5.63
Pear Meadows	Town of Fuquay-Varina	$ 5.18
Swiss Pine Lake	Town of Spruce Pine	$ 5.96
Brookwood/Lagrange Service Areas		
Kelly Hills	Fayetteville PWC	$ 2.92
Bretton Woods	Fayetteville PWC	$ 2.92
Raintree	Fayetteville PWC	$ 2.92
Colony Village	Fayetteville PWC	$ 2.92
Windsong	Fayetteville PWC	$ 2.92
Porter Place	Fayetteville PWC	$ 2.92
Thornwood	Fayetteville PWC	$ 2.92
County Walk	Fayetteville PWC	$ 2.92
Lands Down West	Fayetteville PWC	$ 2.92

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Service Area	Water Provider	Usage Charge/ 1,000 gallons
S & L Estates	Fayetteville PWC	$ 2.92
Tarleton Plantation	Fayetteville PWC	$ 2.92
Springdale	Fayetteville PWC	$ 2.92
Ridge Manor	Fayetteville PWC	$ 2.92
Forest Lake	Fayetteville PWC	$ 2.92
Arden Forest	Fayetteville PWC	$ 2.92
Wendemere	Fayetteville PWC	$ 2.92
Jena-Shane	Fayetteville PWC	$ 2.92
Stoney Point	Fayetteville PWC	$ 2.92
Woodland Run	Town of Linden	$ 5.23

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AQUA NORTH CAROLINA, INC.
PURCHASED SEWER RATES

Aqua North Carolina Service Areas

Monthly Metered Service where bulk service purchased from Charlotte (Park South Station and Parkway Crossing residential and commercial):

Base facility charge, zero usage (based on meter size)	Same as commercial charges listed on Appendix A-1, Page 4
Usage charge, per 1,000 gallons	$ 6.45

Hawthorne at the Greene Apartments, Woodland Farm, and Beaver Farms Subdivision – Mecklenburg County: (See Docket No. W-899, Sub 37 and Docket No. W-218, Subs 357, 517, and 526)

Base facilities charge (to be collected and delivered to Carolina Water Service, Inc. of North Carolina[1] for treatment of the wastewater), per month	$ 47.94 per REU [2]

Each apartment building at Hawthorne at the Greene Apartments (formerly Vista Park Apartments) will be considered 92.42% occupied on an ongoing basis for billing purposes as soon as the certificate of occupancy is issued for the apartment building.

Collection service/commodity charge (based on City of Charlotte's master meter reading), per 1,000 gallons	$ 6.75

[1] On August 17, 2016, in Docket No. W-1044, Sub 24, et al., the North Carolina Utilities Commission issued an Order Approving Merger. In accordance with the Order, and pursuant to the Articles of Merger filed with the North Carolina Department of the Secretary of State on August 30, 2016, Bradfield Farms Water Company was merged into Carolina Water Service, Inc. of North Carolina effective August 30, 2016.

[2] Residential Equivalent Unit.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-218, Sub 526, on this the 26th day of October, 2020.

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AQUA NORTH CAROLINA, INC.
SCHEDULE OF CONNECTION FEES

SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE – SEWER
Alan Acres	$ 800.00	
Allendale	$ 500.00	
Altice Estates	$ 800.00	
Amy Acres	$ 500.00	
Apple Grove	$ 500.00	
Applegate	$ 500.00	
Arbor Run	$ 500.00	
Armfield, Phases 1A, 1B, 2, 3, 4, 5	$ 500.00	
Ashe Plantation	$ 725.00	
Ashebrook Woods	$ 500.00	
Ashton Park	$ 500.00	
Auburndale	$ 500.00	
Autumn Acres	$ 800.00	
Avendale		$3,500.00
Avocet, Phases1A, 1B, 1C, 1D, 1E, 2, 3, 4, 5	$ 500.00	$ 500.00
Bakersfield	$ 500.00	
Ballard Farm	$ 500.00	
Ballentine Place	$ 500.00	
Balls Creek	$ 800.00	
Barkwood Lane	$1,200.00	
Bayberry	$ 800.00	
Beacon Hill	$ 500.00	
Beacon Hills	$ 800.00	
Beau Rivage	$ 969.00	$ 822.00
Beau Rivage Market Place Shopping Center	$1,000.00	
Beechwood Cove	$ 500.00	
Belews Landing	$ 500.00	
Bella Port		$2,500.00
Bells Crossing, Phases 1, 2, 3, 4	$1,000.00	
Bennett Place		$1,000.00
Berklee Reserve	$ 500.00	
Bethel Forest	$ 500.00	
Betts Brook	$ 500.00	
Beverly Acres	$ 800.00	

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SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Bexley Place	$ 500.00	
Birkhaven	$ 500.00	
Blue Water Cove	$ 500.00	
Bogue Watch		$2,500.00
Bonaire	$ 500.00	
Brafford Farms	$ 800.00	
Briar Creek	$ 500.00	
Brickfield	$ 400.00	
Bridgeport	$ 800.00	
Bridle Wood	$ 500.00	
Brights Creek	$ 500.00	$ 500.00
Brinley's Cove	$ 500.00	
Brook Forest	$ 800.00	
Buck Springs Plantation	$1,000.00	
Carolina Marina		$10,000.00
Cameron Point	$ 500.00	
Candy Creek	$ 500.00	
Cane Bay	$ 500.00	$ 500.00
Cannonsgate		$2,500.00
Canterbury Trails	$ 500.00	
Capeside Village	$ 750.00	$1,000.00
Carmel Hills	$ 800.00	
Carmel Park	$ 800.00	
Cassimir Commons	$ 750.00	$1,000.00
Castle Bay	$ 500.00	$ 500.00
Castlewood	$ 800.00	
Catawba Shores	$ 800.00	
Cedar Chase	$ 500.00	
Cedar Creek	$ 500.00	
Cedar Grove	$ 800.00	
Cedar Valley	$ 800.00	
Chapelwood Acres	$ 800.00	
Charles Place at Arbor Run	$ 500.00	
Chatham	$ 500.00	
Clarendon Gardens (includes main extension)	$1,125.00	
Cliftwood West	$ 800.00	

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SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE – SEWER
Clear Meadow	$ 175.00	
Clubview Estates 1	$ 800.00	
Collybrooke, Phases 1, 1A, 2	$ 500.00	
Colvard Farms, Phase 9		$ 500.00
Copperfield (Gaston)	$ 800.00	
Coral Ridge	$1,000.00	$2,500.00
Country Acres	$ 800.00	
Country Acres MHP	$ 800.00	
Country Crossing, Phases I, II, and III	$ 750.00	
Country Crossing, Phases IV and V	$ 670.50	
Country Knolls	$ 800.00	
Country Meadows	$ 800.00	
Country Valley Ext (Lots 7G, 8G, 9G, 12E, 13E, 14E, 15E, 16E, 17F)	$2,500.00	
Country Woods	$ 800.00	
Countryside	$ 500.00	
Crabtree II	$ 500.00	
Craig Gardens	$ 800.00	
Creedmoor Village Shopping Center	$ 500.00	
Creekside	$ 500.00	
Creekside Shores	$1,000.00	
Crestview (Rowan County)	$ 500.00	
Crestview (Cabarrus County)	$ 800.00	
Cross Creek	$ 500.00	
Crutchfield Farms	$ 500.00	
Dalewood/Monteray	$ 800.00	
Deer Path	$ 500.00	
Deerwood	$ 500.00	
Dolphin Bay		$1,000.00
Dorsett Downs	$ 500.00	
Eagle Landing	$ 500.00	
East Bank	$ 750.00	$1,000.00
East Chestnut	$ 800.00	
East Gaston MHP	$ 500.00	
Eastlake	$ 850.00	$1,000.00
Edgewood Acres I & II	$ 800.00	
El Camino	$ 800.00	

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SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Emerald Plantation		Actual Cost
Enoch Turner	$ 500.00	
Epes Trucking	$ 500.00	
Estates at Meadow Ridge	$ 500.00	
Ethan's Gate	$ 500.00	
Ethan's Glen	$ 500.00	
Fairfax	$ 800.00	
Fairview Park	$ 800.00	
Fairview Wooded Acres	$ 800.00	
Falls Creek	$ 500.00	
Fallscrest	$ 800.00	
Farmwood	$ 800.00	
Ferguson Village	$ 500.00	
Fleetwood Acres I	$ 800.00	
Fleetwood Falls; Fleetwood Falls, Sect 15	$ 500.00	
Flowers Plantation Development (Buffalo Creek)	$6.25 / gpd of capacity	$11.00 / gpd of capacity
Flowers Plantation Development (Neuse Colony)	$6.25 / gpd of capacity	$9.47 / gpd of capacity
Fontain Village	$ 800.00	
Forest Acres	$ 800.00	
Forest Cove	$ 800.00	
Forest Pines	$ 500.00	
Forest Ridge	$ 500.00	
Fountain Trace	$ 800.00	
Fox Fire	$ 800.00	
Fox Ridge	$ 800.00	
Fox Run (Gaston)	$ 800.00	
Foxbury	$ 500.00	
Foxbury Meadows	$ 500.00	
Freemont Park	$ 500.00	
Gallagher Trails	$ 800.00	
Gates at Ethan's Glen	$ 500.00	
Glennburn (Sub 385)	$1,500.00	
Glencroft (Catawba)	$ 500.00	
Governors Club		$4,500.00
Governors Forest		$4,500.00
Governors Village		$4,500.00

Grayson Park	$ 500.00	
Graystone Forest	$ 500.00	$ 350.00

SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Green Acres MHP	$ 800.00	
Green Meadows	$ 800.00	
Greenwood	$ 500.00	
Hanover Downs	$ 800.00	
Happy Valley	$ 500.00	
Hartman Farms	$ 500.00	
Hasentree, Phases 1-3, 4A, 4B, 4C, 5, 6A, 6B, 6C, 7, 8, 9, 10, 11, 15A, 15B, 15E		$2,500.00
Heartwood	$ 500.00	
Heather Acres	$ 800.00	
Heather Glen	$ 200.00	
Heritage Farms	$ 500.00	
Heritage West	$ 500.00	
Herman Acres	$ 800.00	
Hickory Creek (Houses on Basswood Way Only)	$ 500.00	
Hickory Ridge	$ 500.00	
Hidden Creek	$ 500.00	
Hidden Hills	$ 500.00	
Hidden Valley (Chatham County)	$ 500.00	
Hidden Valley (Catawba County)	$ 800.00	
High Grove, Phase 3	$ 500.00	
High Meadows	$ 725.00	
Hillsboro	$ 500.00	
Hilltop	$ 500.00	
Holiday Hills	$ 500.00	
Hollywood Acres	$ 800.00	
Homestead-Catawba	$ 500.00	
Hoyles Creek	$ 500.00	
Huntcliff	$ 500.00	
Hunters Mark	$ 500.00	
Hunters Ridge	$ 500.00	
Hunting Ridge	$ 500.00	
Huntley Glen Townhomes, Phase 2	$ 700.00	

Huntwood	$ 500.00	
Idlewild Park	$ 800.00	
Ingram Estates	$ 500.00	
Inlet Point Harbor	$ 750.00	$1,000.00

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SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE – SEWER
Inlet Point Harbor Extension	$1,000.00	
Inlet Watch	$ 750.00	$1,000.00
Inlet Watch-irrigation meters	$ 300.00	
Interlaken	$ 500.00	
Island Bridge Way	$ 750.00	$1,000.00
Jack's Landing	$1,000.00	
Jamestowne	$ 500.00	
Keltic Meadows	$ 800.00	
Kendale Woods	$ 940.00	
Kimberly Courts	$ 500.00	
Kings Acres	$ 500.00	
Knob Creek	$ 500.00	
Knolls Phases I and II only	$ 500.00	
Knollview	$ 500.00	
Knollwood	$1,500.00	
Knoxhaven	$ 500.00	
Kynwood	$ 500.00	
Lakeridge	$ 500.00	
Lakewood	$ 800.00	
Lamar Acres	$ 800.00	
Lancer Acres	$ 500.00	
Laurel Acres	$ 500.00	
Laurel Woods	$ 500.00	
Lazy S	$ 800.00	
Lea Landing	$1,000.00	$2,500.00
Lennox Woods	$ 500.00	
Lighthouse Village	$ 750.00	$1,000.00
Linville Oaks	$ 500.00	
Little River Run	$ 800.00	

WATER AND SEWER – RATE INCREASE

Long Shoals	$ 800.00	
Love Point	$ 500.00	
Lynmore	$ 800.00	
MacGregor Downs	$ 800.00	
Magnolia Place	$ 850.00	$1,000.00
Magnolia Springs	$ 800.00	
Mallard Crossing	$ 500.00	
Mallardhead	$ 500.00	
Maplecrest	$ 800.00	

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SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Mariners Pointe, Phase 1	$ 450.00	
Mar-Lyn Forest	$ 500.00	
Meadow Creek	$ 500.00	
Meadow Ridge	$ 500.00	
Meadow Run	$ 500.00	
Meadowbrook	$ 500.00	
Mill Creek Landing	$1,000.00	
Mineral Springs	$ 500.00	
Monticello Estates	$ 500.00	
Montreaux f/k/a Montrose	$ 500.00	
Moorlands Reserve	$1,333.00	
Moratuck Manor	$1,000.00	
Morningside Park	$ 800.00	
Morris Grove	$ 500.00	
Morristown	$1,000.00	
Moss Haven	$ 800.00	
Mount Vernon Crossing, Phase 3	$ 500.00	
Mountain Creek	$ 500.00	
Mountain Point	$ 350.00	
Mountainbrook	$ 800.00	
Murray Hills	$ 800.00	
Myrtlewood	$ 800.00	
Nantucket Village	$ 500.00	
Nautical Green	$ 750.00	$1,000.00
Neuse Colony	$2,000.00	$1,000.00

Neuse River Village	$ 500.00	$ 500.00
New Chartwell	$ 500.00	
Normandy Glen	$ 500.00	
Norwood Place	$1,333.00	
Oak Harbor (excludes Knox Realty)	$1,750.00	
Oak Hill	$ 800.00	
Oakley Park	$ 800.00	
Old Cape Cod	$ 750.00	$1,000.00
Old Providence	$ 800.00	
Papillon, Phase 2	$ 500.00	
Paradise Point	$ 800.00	
Park South Station	$ 700.00	
Parkway Crossing	$ 700.00	
Parkwood	$ 500.00	

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SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Peabody Forest	$ 500.00	
Pearman Estates	$ 500.00	
Pepper Ridge	$ 500.00	
Pheasant Ridge	$ 500.00	
Phillips Landing	$ 800.00	
Piedmont Estates	$ 500.00	
Pilot's Ridge, Lots 22 through 29	$1,000.00	
Pine Knolls	$ 500.00	
Pine Meadows	$ 500.00	
Pineview	$ 500.00	
Pinewood Acres	$ 800.00	
Pleasant Gardens	$ 500.00	
Polk's Landing	$ 500.00	
Polk's Trail	$ 500.00	
Ponderosa	$ 500.00	
Providence Acres	$ 800.00	
Providence North	$ 500.00	
Quail Meadows	$ 500.00	
Quail Oaks	$ 500.00	
Quail's Nest	$ 500.00	
Raintree	$ 800.00	

Red Mountain	$ 500.00	
Regency Village	$ 500.00	
Richwood Acres	$ 500.00	
Ridgecrest	$ 500.00	
Ridgeview Park	$ 800.00	
Ridgeway Courts	$ 500.00	
Ridgewood	$ 500.00	
River Oaks (Guilford County)	$ 500.00	
River Oaks (New Hanover County)	$ 750.00	
River Oaks, Phase 8 (New Hanover County)	$1,000.00	$2,500.00
River Park	$1,500.00	$10.00 / gpd of capacity
River Point at Beau Rivage	$ 969.00	$ 822.00
River Ridge Run	$ 500.00	
River Run	$ 500.00	

SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Riverside at Oak Ridge	$ 500.00	
Riverton Place	$ 800.00	
Riverview	$ 500.00	
Riverwoods	$ 800.00	
Robinfield	$ 800.00	
Roland Place	$ 750.00	$1,000.00
Roland Place extension	$1,000.00	
Rolling Hills	$ 500.00	
Rolling Meadows	$ 800.00	
Round Tree Ridge		$2,500.00
Rustic Trials	$ 800.00	
Saddlewood	$ 800.00	
Sailors Lair	$1,000.00	$2,500.00
Sanford's Creek	$ 500.00	
Seabreeze	$ 750.00	$1,000.00
Seabreeze Sound Extension	$1,000.00	$2,500.00
Seagate I	$ 500.00	
Seagate IV	$ 500.00	
Sedgley Abby	$ 750.00	$1,000.00
Shade Tree	$ 500.00	

WATER AND SEWER – RATE INCREASE

Shadow Oaks	$ 500.00	
Shangri-la (Catawba)	$ 800.00	
Shangri-la (Gaston)	$ 800.00	
Shaw Hill Estates	$ 500.00	
Sherwood Forest (Catawba County)	$ 500.00	
Shiloh	$ 500.00	
Shipwatch	$ 750.00	$1,000.00
Silverstone	$ 800.00	
Skyland Drive	$ 800.00	
Smoke Ridge	$ 500.00	
Smokerise	$ 500.00	
Snow Creek	$ 500.00	
Sopanos Point	$ 750.00	$1,000.00
South Bourne	$ 500.00	
South Forest	$ 800.00	
South Fork (Catawba)	$ 500.00	
South Fork (Gaston)	$ 800.00	
South Hill	$ 800.00	

SYSTEM NAME	**CONNECTION FEE - WATER**	**CONNECTION FEE - SEWER**
South Hill Estates	$ 800.00	
South Point Landing	$ 800.00	
Southampton	$ 800.00	
Southgate	$ 800.00	
Southwood (Wake)	$ 800.00	
Spencer Road Acres	$ 800.00	
Spinnaker Bay	$ 800.00	
Spinnaker Pointe	$1,000.00	
Spring Hill/Springdale	$ 800.00	
Spring Shores	$ 800.00	
Spring Valley	$ 800.00	
Springdale (Guilford)	$ 500.00	
Springfield Estates	$ 500.00	
Springhaven (Wake)	$ 800.00	
Sprinkle	$ 500.00	
Stanleystone Estates	$1,000.00	

WATER AND SEWER – RATE INCREASE

Starland Park	$ 800.00	
Sterlingshire	$ 500.00	
Stonehouse Acres	$1,000.00	
Stonebridge	$ 500.00	
Stoneridge	$ 500.00	
Stoney Brook	$ 800.00	
Sturbridge Village	$ 500.00	
Summerfield Farms	$ 500.00	
Summerwind	$ 500.00	
Sunset Bay (3 digit lot #s on Roundstone Road)	$2,500.00	
Sunset Hills	$ 800.00	
Sunset Park	$ 800.00	
Swiss Pine Lake	$ 800.00	
Tablerock	$ 800.00	
Telfair Forrest	$ 750.00	$1,000.00
The Cape, Section A	$ 750.00	$1,000.00
The Cape, Section B	$ 750.00	$1,000.00
The Gardens at Flowers	$ 850.00	$1,000.00
The Reserve at Falls Lake, Phases 1, 2, 3	$ 500.00	
The Sanctuary	$ 750.00	$1,000.00
The Village at Motts Landing, Phases 1&2	$1,000.00	
The Vineyards	$ 500.00	

SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Thornton Ridge	$ 400.00	
Tidelands on the River	$1,000.00	
Timberlake	$ 400.00	
Timberline	$ 500.00	
Timberline Shores	$1,000.00	
Tralee Place	$1,000.00	
Triple Lakes	$ 500.00	
Tuxedo	$ 800.00	
Twelve Oaks	$ 500.00	
Twelve Oaks Cadet Drive Extension	$1,700.00	
Twin Creek	$3,000.00	
Twin Oaks	$ 500.00	

WATER AND SEWER – RATE INCREASE

Valley Acres	$ 500.00	
Valley Dale	$ 500.00	
Village Woods	$ 500.00	
Walker Estates	$ 500.00	
Waterford		$2,500.00
Watts	$ 800.00	
Weatherstone	$ 350.00	
Wellington	$ 500.00	
Wesley Acres	$ 800.00	
West View at River Oaks	$1,000.00	$2,500.00
Westfall – 100 foot wide lots (47 lots)		$2,750.00
Westfall – 80 foot wide lots (60 lots)		$2,565.00
Westfall – 60 foot wide lots (69 lots)		$2,250.00
Westfall – Estate Lots (64 lots)		$3,150.00
Westfall – Amenities		$2,000.00
Westside Hills	$ 500.00	
Willard Run/San Siro	$ 500.00	
Willow Creek		$ 500.00
Willow Glen at Beau Rivage	$ 500.00	$ 500.00
Willow Oaks	$ 800.00	
Wilson Farm	$ 500.00	
Wimbledon	$1,500.00	
Winding Forest	$ 500.00	
Windspray	$ 750.00	$1,000.00
Windswept, Phase 1	$ 750.00	$1,000.00

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SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Windswept, Phases 2 & 3		$ 500.00
Windwood Acres	$ 800.00	
Woodbridge	$ 500.00	
Woodford (Hawks Ridge)	$ 500.00	
Woodlake	$ 800.00	$ 800.00
Woodlake – Irrigation Meter	$ 300.00	
Woodland Hills	$ 500.00	
Woodland Shores	$1,000.00	
Woodlawn	$ 800.00	
Woodleigh	$ 800.00	
Wright Beaver	$ 500.00	
Yorkwood Park	$ 800.00	

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-218, Sub 526, on this the 26th day of October, 2020.

APPENDIX A-4

AQUA NORTH CAROLINA, INC.
WATER AND SEWER SYSTEM IMPROVEMENT CHARGES

WATER SYSTEM IMPROVEMENT CHARGE

All Aqua NC water systems except as noted below	0.00% 1/ and 2/
Water systems in Brookwood and LaGrange service areas	0.00% 1/ and 2/
Water systems in Fairways and Beau Rivage service areas	0.00% 1/ and 2/

SEWER SYSTEM IMPROVEMENT CHARGE

WATER AND SEWER – RATE INCREASE

All Aqua NC sewer systems except as noted below	0.00% [1/ and 3/]
Sewer systems in Fairways and Beau Rivage service areas	0.00% [1/ and 3/]

1/ Reset to zero pursuant to the Commission's Order in Docket No. W-218, Sub 526.

2/ Upon approval by further order of the Commission, the Water System Improvement Charge will be applied to the total water utility bill of each customer under the Company's applicable rates and charges.

3/ Upon approval by further order of the Commission, the Sewer System Improvement Charge will be applied to the total sewer utility bill of each customer under the Company's applicable rates and charges.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-218, Sub 526, on this the 26th day of October, 2020.

APPENDIX B-1
PAGE 1 OF 7

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 526

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	
202 MacKenan Court, Cary, North Carolina	)	NOTICE TO CUSTOMERS IN
27511, for Authority to Increase Rates for Water	)	AQUA NORTH CAROLINA
and Sewer Utility Service in All of Its Service	)	SERVICE AREAS
Areas in North Carolina	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Aqua North Carolina, Inc. (Aqua NC), to increase its rates for water and sewer utility service in its service areas in North Carolina. The new approved water and sewer rates for Aqua NC customers, excluding the Brookwood and LaGrange service areas in Cumberland and Hoke Counties and the Fairways and Beau Rivage service areas in New Hanover County, are as follows:

WATER UTILITY SERVICE

Monthly Metered Service (Residential and Commercial customers)

Base facility charge (zero usage, based on meter size)

<1" meter	$ 20.70
1" meter	$ 51.75
1-1/2" meter	$103.50
2" meter	$165.60
3" meter	$310.50
4" meter	$517.50
6" meter	$1,035.00

Usage charge, per 1,000 gallons	$ 6.38

All service areas unless noted differently below

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PAGE 2 OF 7

Conservation Pilot Program
Arbor Run, Bayleaf, Merion and Pebble Bay Subdivisions

Tiered usage charge, per 1,000 gallons (residential)

1 - 4,000 gallons	$	4.14
4,001 - 8,000 gallons	$	6.21
8,001 - 15,000 gallons	$	9.32
15,001+ gallons	$	12.42

Tiered usage charge, per 1,000 gallons (irrigation meters)

1 - 15,000 gallons	$	9.32
15,001+ gallons	$	12.42

Bulk Purchased Water Systems
Monthly base facility charge same as above

WATER AND SEWER – RATE INCREASE

Usage charge per 1,000 gallons, where water purchased for resale as shown below:

Service Area	Water Provider	Usage Charge
Twin Creeks	City of Asheville	$ 4.96
Heather Glen and Highland	City of Belmont	$14.40
Southpoint Landing	City of Belmont	$14.40
Park South	City of Charlotte	$ 2.19
Parkway Crossing	City of Charlotte	$ 2.19
Springhill / Springdale	City of Concord	$ 5.42
Hoopers Valley	City of Hendersonville	$ 3.47
Crystal Creek	City of Hendersonville	$ 3.47
Rambling Ridge	City of Hendersonville	$ 3.47
Brookwood	City of Hickory (outside city)	$ 3.25
Heritage Farms	City of Hickory (inside city)	$ 3.25
Cedarwood Estates	City of Hickory (inside city)	$ 3.25
Hill-N-Dale	City of Lincolnton	$ 9.21
East Shores	City of Morganton	$ 2.51
Greenfield	City of Mount Airy	$ 6.69
Bett's Brook	City of Newton	$ 3.29
Crestwood	Davidson Water, Inc.	$ 4.76
Lancer Acres	Davidson Water, Inc.	$ 4.76
Beard Acres	Davidson Water, Inc.	$ 4.76
Woodlake Development	Harnett County	$ 2.78
Beechwood Cove	Chatham County	$ 7.04

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Service Area	Water Provider	Usage Charge
Chatham	Chatham County	$ 7.04
Cole Park Plaza Shopping Center	Chatham County	$ 9.98
Hidden Valley	Chatham County	$ 7.04
Polks Landing	Chatham County	$ 7.04
Chapel Ridge	Town of Pittsboro	$13.69
Laurel Ridge	Town of Pittsboro	$13.69
The Parks at Meadowview	Town of Pittsboro	$13.69
River Hill Heights	Iredell Water Corp.	$ 3.61
Bedford at Flowers Plantation	Johnston County	$ 2.66
Bennett Place	Johnston County	$ 2.66
Chatham	Johnston County	$ 2.66
Cottages at Evergreen	Johnston County	$ 2.66

WATER AND SEWER – RATE INCREASE

Cottonfield Village	Johnston County	$ 2.66
Creekside Place	Johnston County	$ 2.66
Eastlake at Flowers Plantation	Johnston County	$ 2.66
Evergreen	Johnston County	$ 2.66
Flowers Crest	Johnston County	$ 2.66
Flowers Shopping Center	Johnston County	$ 2.66
Forge Creek	Johnston County	$ 2.66
Longleaf	Johnston County	$ 2.66
Magnolia	Johnston County	$ 2.66
Magnolia Place/Village	Johnston County	$ 2.66
Mill Creek North	Johnston County	$ 2.66
Mill Creek West	Johnston County	$ 2.66
Neuse Colony	Johnston County	$ 2.66
North Farm	Johnston County	$ 2.66
North Farm Cottages	Johnston County	$ 2.66
North Village	Johnston County	$ 2.66
Parkway Center/Village	Johnston County	$ 2.66
Peachtree	Johnston County	$ 2.66
Pineville Club	Johnston County	$ 2.66
Pineville East	Johnston County	$ 2.66
Pineville East Cottages/Palmetto Pl.	Johnston County	$ 2.66
Pineville East Estates	Johnston County	$ 2.66
Pineville West	Johnston County	$ 2.66
Plantation Park	Johnston County	$ 2.66
Plantation Pointe	Johnston County	$ 2.66
Poplar Woods	Johnston County	$ 2.66
River Dell East	Johnston County	$ 2.66
River Dell Townes	Johnston County	$ 2.66

Service Area	Water Provider	Usage Charge
Riverdell Elementary School	Johnston County	$ 2.66
Ross Landing	Johnston County	$ 2.66
South Plantation	Johnston County	$ 2.66
South Quarter	Johnston County	$ 2.66
Southgate	Johnston County	$ 2.66
Summerset Place	Johnston County	$ 2.66
Sun Ridge Farms	Johnston County	$ 2.66
Sweetgrass	Johnston County	$ 2.66
The Gardens at Flowers Plantation	Johnston County	$ 2.66

WATER AND SEWER – RATE INCREASE

The Meadows	Johnston County	$ 2.66
The Nine	Johnston County	$ 2.66
The Woodlands	Johnston County	$ 2.66
Trillium	Johnston County	$ 2.66
Village at Flowers Plantation	Johnston County	$ 2.66
Walker Woods	Johnston County	$ 2.66
Watson's Mill	Johnston County	$ 2.66
West Ashley	Johnston County	$ 2.66
Whitfield at Flowers Plantation	Johnston County	$ 2.66
Wilders Woods and Extension	Johnston County	$ 2.66
Holly Hills	Town of Forest City	$ 5.63
Pear Meadows	Town of Fuquay-Varina	$ 5.18
Swiss Pine Lake	Town of Spruce Pine	$ 5.96

Monthly Unmetered service (flat rate)

Residential customers	$ 46.22
Commercial customers (per *REU)	$ 73.63
*(REU = Residential Equivalent Unit)	

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PAGE 5 OF 7

SEWER UTILITY SERVICE

Monthly Unmetered Service (flat rate)
All service areas unless noted differently below

Residential customers	$ 75.38
Commercial customers (per *REU)	$ 105.53
*(REU = Residential Equivalent Unit)	

STEP system flat rate (Monticello, Holly Brook, Saddleridge) $ 32.00

Residential and Commercial Monthly Metered Service and all the Park South Station and Parkway Crossing Service Areas (based on metered water usage)

Base facility charge (zero usage, based on water meter size)
All service areas unless noted differently below

WATER AND SEWER – RATE INCREASE

<1" meter	$ 60.43
1" meter	$ 151.08
1½" meter	$ 302.15
2" meter	$ 483.44
3" meter	$ 906.45
4" meter	$1,510.75
6" meter	$3,021.50

Usage charge, per 1,000 gallons $ 2.99
All service areas unless noted differently below

Carolina Meadows, Inc. will be charged 50% of the sum of all contributory water meter base facility charges, which is currently 186 REUs or 50% of 372 REUs.

Park South Station and Parkway Crossing Service Areas

Base facility charge:	As shown above
Usage charge, per 1,000 gallons	$ 6.45

Hawthorne Green Apartments, Woodland Farm, and Beaver Farms Subdivision

Base facility charge per REU	$ 47.94
Usage charge, per 1,000 gallons	$ 6.75

APPENDIX B-1
PAGE 6 OF 7

IMPACT ON AVERAGE RESIDENTIAL BILL

The impact on the average monthly metered residential bill including the reset of the water and sewer system improvement charge (WSIC and SSIC) is as follows:

	Metered Water	Sewer
Average bill under prior rates	$49.70	$72.87 (flat)
Average bill under approved rates	$52.60	$75.38 (metered)

The average monthly residential bills are based on the uniform rates for non-purchased water and sewer systems based on an approximate average usage of 5,000 gallons per month. The average residential bills for the bulk purchased water and sewer systems will vary.

WATER AND SEWER – RATE INCREASE

RATE ADJUSTMENT MECHANISM:

The Commission-authorized WSIC and SSIC rate adjustment mechanisms continue in effect. These charges have been reset to zero in the Docket No. W-218, Sub 526 rate case, but Aqua NC may, under the Rules and Regulations of the Commission, apply for a rate surcharge on November 1, 2020, to become effective January 1, 2021. The WSIC/SSIC mechanisms are designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for water and sewer system improvements. The WSIC/SSIC mechanisms are subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanisms may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding.

CREDIT/REFUNDS DUE TO REDUCTIONS IN CORPORATE FEDERAL AND STATE INCOME TAX RATES:

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 previous rate case proceeding, the Commission reduced Aqua NC's revenue requirement to reflect the reduction in the federal corporate income tax rate from 35% to 21%, on the Company's ongoing federal income tax expense.

With respect to excess deferred income taxes (EDIT) resulting from reductions in the corporate federal and state income tax rates, the Commission is requiring that: (a) Aqua NC's Protected Federal EDIT shall continue to be flowed back to customers following the tax normalization rules utilizing the average rate assumption method (ARAM) as required by the rules of the Internal Revenue Service; (b) Aqua NC's Unprotected Federal EDIT shall continue to be returned to ratepayers through a levelized rider; and (c) Aqua NC's State EDIT shall continue to be returned to customers through a levelized rider. The Unprotected Federal EDIT and State EDIT refund riders will expire once the entire balances are appropriately returned to customers by the end of the three-year period that began on December 18, 2018.

Aqua NC will provide the applicable dollar amounts concerning the federal and state EDIT riders (refunds) shown as separate line items on individual customers' monthly bills, along with explanatory information.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of October, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 526

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	
202 MacKenan Court, Cary, North Carolina	)	NOTICE TO CUSTOMERS
27511, for Authority to Increase Rates for	)	IN BROOKWOOD AND
Water and Sewer Utility Service in All of Its	)	LAGRANGE SERVICE AREAS
Service Areas in North Carolina	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Aqua North Carolina, Inc. (Aqua NC), to increase its rates for water utility service in its Brookwood and LaGrange service areas in Cumberland and Hoke Counties. The new approved water rates are as follows:

Monthly Metered Service (Residential and Commercial customers)

Base facility charge, per month (zero usage, based on meter size)

<1" meter	$ 16.01
1" meter	$ 40.03
1½" meter	$ 80.05
2" meter	$ 128.08
3" meter	$ 240.15
4" meter	$ 400.25
6" meter	$ 800.50

Usage charge, per 1,000 gallons	$ 4.57

All service areas unless noted differently below

Bulk Purchased Water Systems

Monthly base facility charge same as above

WATER AND SEWER – RATE INCREASE

APPENDIX B-2
PAGE 2 OF 4

Usage charge per 1,000 gallons, where water purchased for resale as shown below

Service Area	Water Provider	Usage Charge
Kelly Hills	Fayetteville PWC	$ 2.92
Bretton Woods	Fayetteville PWC	$ 2.92
Raintree	Fayetteville PWC	$ 2.92
Colony Village	Fayetteville PWC	$ 2.92
Windsong	Fayetteville PWC	$ 2.92
Porter Place	Fayetteville PWC	$ 2.92
Thornwood	Fayetteville PWC	$ 2.92
County Walk	Fayetteville PWC	$ 2.92
Lands Down West	Fayetteville PWC	$ 2.92
S & L Estates	Fayetteville PWC	$ 2.92
Tarleton Plantation	Fayetteville PWC	$ 2.92
Springdale	Fayetteville PWC	$ 2.92
Ridge Manor	Fayetteville PWC	$ 2.92
Forest Lake	Fayetteville PWC	$ 2.92
Arden Forest	Fayetteville PWC	$ 2.92
Wendemere	Fayetteville PWC	$ 2.92
Jena-Shane	Fayetteville PWC	$ 2.92
Stoney Point	Fayetteville PWC	$ 2.92
Woodland Run	Town of Linden	$ 5.23

Monthly Unmetered Service/REU (flat rate)	
Residential Rate	$ 37.24
Commercial customers (per *REU)	$ 52.56
*(REU = Residential Equivalent Unit)	

IMPACT ON AVERAGE RESIDENTIAL BILL

The impact on the average monthly metered residential bill including the reset of the WSIC is as follows:

	Water
Average bill under prior rates	$34.00
Average bill under approved rates	$38.86

The average monthly residential bills are based on the rates for non-purchased water systems based on an approximate average usage of 5,000 gallons per month. The average residential bills for the bulk purchased water systems will vary.

APPENDIX B-2
PAGE 3 OF 4

RATE ADJUSTMENT MECHANISM:

The Commission-authorized WSIC and SSIC rate adjustment mechanisms continue in effect. These charges have been reset to zero in the Docket No. W-218, Sub 526 rate case, but Aqua NC may, under the Rules and Regulations of the Commission, apply for a rate surcharge on November 1, 2020, to become effective January 1, 2021. The WSIC/SSIC mechanisms are designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for water and sewer system improvements. The WSIC/SSIC mechanisms are subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanisms may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding.

CREDIT/REFUNDS DUE TO REDUCTIONS IN CORPORATE FEDERAL AND STATE INCOME TAX RATES:

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 previous rate case proceeding, the Commission reduced Aqua NC's revenue requirement to reflect the reduction in the federal corporate income tax rate from 35% to 21%, on the Company's ongoing federal income tax expense.

With respect to excess deferred income taxes (EDIT) resulting from reductions in the corporate federal and state income tax rates, the Commission is requiring that: (a) Aqua NC's Protected Federal EDIT shall continue to be flowed back to customers following the tax normalization rules utilizing the average rate assumption method (ARAM) as required by the rules of the Internal Revenue Service; (b) Aqua NC's Unprotected Federal EDIT shall continue to be returned to ratepayers through a levelized rider; and (c) Aqua NC's State EDIT shall continue to be returned to customers through a levelized rider. The Unprotected Federal EDIT and State EDIT refund riders will expire once the entire balances are appropriately returned to customers by the end of the three-year period that began on December 18, 2018.

APPENDIX B-2
PAGE 4 OF 4

Aqua NC will provide the applicable dollar amounts concerning the federal and state EDIT riders (refunds) shown as separate line items on individual customers' monthly bills, along with explanatory information.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of October, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

APPENDIX B-3
PAGE 1 OF 4

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 526

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	
202 MacKenan Court, Cary, North Carolina	)	NOTICE TO CUSTOMERS
27511, for Authority to Increase Rates for	)	IN FAIRWAYS AND
Water and Sewer Utility Service in All of	)	BEAU RIVAGE SERVICE AREAS
Its Service Areas in North Carolina	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Aqua North Carolina, Inc. (Aqua NC), to increase its rates for water utility service and decrease its rates for sewer utility service in its Fairways and Beau Rivage service areas in New Hanover County. The new approved water and sewer rates are as follows:

WATER UTILITY SERVICE

Monthly Metered Service (Residential and Commercial customers)

Base charge, per month (zero usage, based on meter size)	
<1" meter	$ 8.56
1" meter	$ 21.40
1½" meter	$ 42.80
2" meter	$ 68.48
3" meter	$ 128.40
4" meter	$ 214.00
6" meter	$ 428.00
Usage charge, per 1,000 gallons	$ 1.55

Monthly Unmetered Service/REU (flat rate)

Residential Rate	$ 17.91
Commercial customers (per *REU)	$ 23.61
*(REU = Residential Equivalent Unit)	

SEWER UTILITY SERVICE

Monthly Metered Service (Residential and Commercial customers)

Base facility charge (zero usage, based on water meter size)

<1" meter	$ 46.49
1" meter	$ 116.23
1 1/2" meter	$ 232.45
2" meter	$ 371.92
3" meter	$ 697.35
4" meter	$1,162.25
6" meter	$2,324.50
Usage charge, per 1,000 gallons	$ 1.83

Monthly Unmetered Service (flat rate)

Residential customers	$ 54.11
Commercial customers (per *REU)	$ 73.25

*(REU = Residential Equivalent Unit)

IMPACT ON AVERAGE RESIDENTIAL BILL

The impact on the average monthly metered residential bill including the reset of the WSIC and SSIC is as follows:

	Metered Water	Sewer
Average bill under prior rates	$18.26	$58.60 (flat)
Average bill under approved rates	$18.64	$58.39 (metered)

The average monthly residential bills listed above are based on an approximate average usage of 6,500 gallons per month.

APPENDIX B-3
PAGE 3 OF 4

RATE ADJUSTMENT MECHANISM:

The Commission-authorized WSIC and SSIC rate adjustment mechanisms continue in effect. These charges have been reset to zero in the Docket No. W-218, Sub 526 rate case, but Aqua NC may, under the Rules and Regulations of the Commission, apply for a rate surcharge on November 1, 2020, to become effective January 1, 2021. The WSIC/SSIC mechanisms are designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for water and sewer system improvements. The WSIC/SSIC mechanisms are subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanisms may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding.

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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 previous rate case proceeding, the Commission reduced Aqua NC's revenue requirement to reflect the reduction in the federal corporate income tax rate from 35% to 21%, on the Company's ongoing federal income tax expense.

With respect to excess deferred income taxes (EDIT) resulting from reductions in the corporate federal and state income tax rates, the Commission is requiring that: (a) Aqua NC's Protected Federal EDIT shall continue to be flowed back to customers following the tax normalization rules utilizing the average rate assumption method (ARAM) as required by the rules of the Internal Revenue Service; (b) Aqua NC's Unprotected Federal EDIT shall continue to be returned to ratepayers through a levelized rider; and (c) Aqua NC's State EDIT shall continue to be returned to customers through a levelized rider. The Unprotected Federal EDIT and State EDIT refund riders will expire once the entire balances are appropriately returned to customers by the end of the three-year period that began on December 18, 2018.

APPENDIX B-3
PAGE 4 OF 4

Aqua NC will provide the applicable dollar amounts concerning the federal and state EDIT riders (refunds) shown as separate line items on individual customers' monthly bills, along with explanatory information.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of October, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief 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-218, Sub 526, and the Notices were mailed or hand delivered by the date specified in the Order.

This the _____ day of ___________________, 20___.

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-218, Sub 526.

Witness my hand and notarial seal, this the ____ day of _______________, 20____.

____
Notary Public

____
Printed or Typed Name

(SEAL) My Commission Expires: ____________________________
Date

WATER AND SEWER – RATE INCREASE

DOCKET NO. W-1314, SUB 4

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Pluris Webb Creek, LLC,	)	ORDER APPROVING
5950 Berkshire Lane, Suite 800, Dallas, Texas,	)	AGREEMENT AND
75225 for Authority to Increase Rates for Sewer	)	STIPULATION, GRANTING
Utility Service in All Service Areas in Onslow	)	RATE INCREASE, AND
County, North Carolina	)	REQUIRING CUSTOMER NOTICE

HEARD: Wednesday, September 23, 2020, at 6:30 p.m., remotely via Webex

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

APPEARANCES:

For Pluris Webb Creek, LLC:

Daniel C. Higgins, Burns, Day & Presnell, P.A., Post Office Box 10867, Raleigh, North Carolina 27605

For the Using and Consuming Public:

William E. H. Creech, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On March 17, 2020, in the above-captioned docket, Pluris Webb Creek, LLC (Pluris Webb Creek or Company), filed with the North Carolina Utilities Commission (Commission or NCUC) pursuant to Commission Rule R1-17(a), notice of its intent to file an application for a general rate case. On April 27, 2020, the Company filed its verified Application for a general rate increase for sewer utility service rates in all its service areas in Onslow County, North Carolina. Along with its Application, Pluris Webb Creek prefiled the direct testimony of Maurice W. Gallarda, PE, Managing Member, Pluris Holdings, LLC, and Daniel J. Winters, Chief Financial Officer, Pluris Holdings, LLC, and certain information and data required by NCUC Form W-1.

On May 26, 2020, the Commission issued its Order Establishing General Rate Case and Suspending Rates.

On August 6, 2020, Pluris Webb Creek filed Revised Pluris Schedule 10f, a revised schedule of present and proposed rates.

On August 10, 2020, the Commission issued an Order Scheduling Hearings and Requiring Customer Notice. On August 17, 2020, the Company filed a certificate of service demonstrating that Pluris Webb Creek provided notice of this general rate case proceeding to customers as required by the Commission's August 10, 2020 Order.

On August 24, 2020, Pluris Webb Creek filed an update to its operating expenses and rate base. On August 25, 2020, the Company filed a Revised Pluris Schedule 7, which provided updated information concerning development systems acquired or operated since the last rate case.

On September 23, 2020, a remote public hearing was held for the purpose of receiving customer testimony in this matter via Webex, as provided for in the Commission's Order issued August 10, 2020. Testimony from six sworn witnesses was heard by the Commission.

On September 25, 2020, the Public Staff prefiled the testimony and exhibits of Public Staff witnesses D. Michael Franklin, Utilities Engineer, Water, Sewer, and Telephone Division and Benjamin P. Lozier, Financial Analyst, Economic Research Division. The Public Staff also prefiled the affidavit and exhibit of Mary A. Coleman, Staff Accountant, Accounting Division.

On September 29, 2020, Pluris Webb Creek filed a Report Relating to Customer Hearing stating that no quality of service issues were raised by any customer testifying at the public hearing. In its report, Pluris Webb Creek responded to several non-quality of service concerns expressed by customers.

On October 9, 2020, the Public Staff and Pluris Webb Creek filed an Agreement and Stipulation of Settlement (Joint Stipulation), which reflected the parties' agreement on settlement.

On October 21, 2020, the Commission issued an Order Canceling Expert Witness Hearing, Requiring Notice to Customers, Admitting Evidence Into The Record, and Allowing the Filing of Proposed Orders and Briefs.

On November 23, 2020, the Public Staff and Pluris Webb Creek filed a Joint Proposed Order.

On the basis of the Application, the testimony, the affidavit, the Joint Stipulation, and the other evidence of record, the Commission now makes the following

FINDINGS OF FACT

General Matters

1. Pluris Webb Creek is a limited liability company duly organized under the laws of and authorized to do business in the State of North Carolina. Pluris Webb Creek is a franchised public utility providing sewer utility service to customers in North Carolina.

2. Pluris Webb Creek is properly before the Commission, pursuant to Chapter 62 of the General Statutes of North Carolina, for determination of the justness and reasonableness of its proposed rates and charges for its wastewater services provided in its Commission-assigned service area.

3. The appropriate test year for purposes of establishing rates in this docket is the 12-month period ended December 31, 2019, updated through July 31, 2020, for certain changes in plant, revenues, and costs that were not known at the time the Application was filed.

4. Pluris Webb Creek's present rates for sewer service have been in effect since August 2016, pursuant to the Commission's Order dated August 8, 2016, (EO Order) in Docket No. W-864, Sub 11 (EO Docket).

5. Pluris Webb Creek's present and proposed rates are as follows:

	Present Rates	Proposed Rates
Monthly Residential Flat Rate:	$ 37.69	$ 73.38 (1)

(1) All residential customers

	Present Rates	Proposed Rates
Monthly Commercial Metered Rates:		
Base charge, zero usage (minimum charge)		
< 1"	$ 28.34	$ 10.00
1"	$ 28.34	$ 25.00
1.5"	$ 28.34	$ 50.00
2"	$ 25.24	$ 80.00
4"	$ 25.24	$250.00
Usage charge, per 1,000 gallons	$ 9.04	$ 16.50

6. As of the 12-month period ended December 31, 2019, Pluris Webb Creek served approximately 1,354 residential flat rate sewer customers and eight metered commercial sewer customers in its service areas in Onslow County, North Carolina.

The Joint Stipulation

7. The Joint Stipulation is an agreement between the Public Staff and Pluris Webb Creek (the Stipulating Parties), who are the only parties to this docket.

8. The Joint Stipulation resolves all matters in controversy in this docket as between the Stipulating Parties to the case.

9. The Joint Stipulation is the product of 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 who testified at the public witness hearing.

WATER AND SEWER – RATE INCREASE

Acceptance of Stipulation

10. The revenue requirement agreed upon in the Joint Stipulation will provide Pluris Webb Creek and its ratepayers just and reasonable rates.

11. The provisions of the Joint Stipulation are just and reasonable to all parties to this proceeding, as well as Pluris Webb Creek's ratepaying customers, and serve the public interest.

12. It is appropriate to approve the Joint Stipulation in its entirety.

Customer Concerns and Service

13. A total of six customers testified at the public hearing on September 23, 2020. In general, the public witnesses objected to the proposed rate increase relating to Pluris Webb Creek's new membrane bioreactor (MBR) wastewater treatment plant (WWTP). None of the customers voiced any complaint regarding the quality of the service provided by Pluris Webb Creek.

14. Pluris Webb Creek served as the Commission-appointed emergency operator of the Webb Creek Water and Sewage, Inc. (Webb Creek) service area beginning in August 2016 until March 26, 2019, when Pluris Webb Creek became the franchise owner of the service area pursuant to Order dated March 26, 2019, in Docket No. W-864, Subs 11 and 14 and Docket No. W-1314, Sub 1.

15. As emergency operator, Pluris Webb Creek spent more than $900,000 during the period 2016-2019 in an effort to address issues in the Webb Creek sequencing batch reactor (SBR) plant and collection system and the Company was able to achieve reasonable compliance with the North Carolina Department of Environmental Quality (DEQ) requirements.

16. Despite Pluris Webb Creek's investment and efforts to achieve compliance with DEQ's requirements, lingering issues with the SBR plant and collection system continued due to continuing compliance issues that could not be adequately addressed, as well as crucial concerns about the integrity of the existing WWTP. During its site visit on December 4, 2019, the Public Staff observed the worsening condition of the then-operating aged SBR WWTP. Primary concerns included direct discharge from leaking tank vessels and the presence of enterococci in discharge effluent following treatment.

17. Pluris Webb Creek has built a new MBR WWTP 350,000 gallons per day (gpd) treatment capacity to replace the old deteriorated SBR WWTP. The new plant went into service on approximately June 16, 2020. The new MBR plant is sized to serve the legacy Webb Creek service area, a nearby development known as The Pines, and the general vicinity.

18. The overall quality of service provided by Pluris is good.

WATER AND SEWER – RATE INCREASE

Rate Base

19. It is appropriate to treat the letter of credit proceeds of $100,000 obtained by the Commission through forfeiture of Webb Creek's bond security in Docket No. W-864, Sub 11, and disbursed to Pluris Webb Creek in 2019 as cost-free capital and as a reduction to rate base.

20. The appropriate level of rate base used and useful in providing sewer utility service is $6,132,257 for Pluris Webb Creek's operations, consisting of the following components:

Item	Amount
Plant in service	$6,784,276
Accumulated depreciation	(242,905)
Net plant in service	6,541,371
Contributions in aid of construction	(54,000)
Accumulated amortization – CIAC	1,026
Prepaid tap on fees	(128,898)
Customer deposits	(29,175)
Accumulated deferred income taxes - ADIT	(164,156)
Cost free capital	(100,000)
Cash working capital	67,451
Average tax accruals	(1,362)
Original cost rate base	$6,132,257

Operating Revenues

21. The appropriate level of operating revenues under present rates for use in this proceeding is $628,499, consisting of service revenues of $606,592 and miscellaneous revenues of $24,490, reduced by uncollectible accounts of $2,583.

22. Pluris Webb Creek requested an increase in rates that would produce $575,464 in additional total operating revenues after Public Staff adjustments, an increase of 92% over present annual total operating revenues.

Maintenance and General Expense

23. The appropriate level of operation and maintenance expense for Pluris Webb Creek's operations for use in this proceeding is $539,607.

24. It is appropriate for Pluris Webb Creek to recover total rate case expenses of $85,000 related to the current proceeding which is comprised of $37,500 in legal fees, $42,500 in capitalized labor, and $5,000 in postage and printing to mail customer notices, the rate case filing fee, and miscellaneous expenses.

25. It is appropriate to amortize the total rate case expenses for the current proceeding over five years, resulting in an annual level of rate case expense of $17,000, as agreed to by the Stipulating Parties.

Depreciation, Amortization Expense, Regulatory Fee and Taxes

26. The appropriate level of depreciation expense for use in this proceeding is $197,847 and the appropriate level of amortization expense - CIAC for use in this proceeding is ($898).

27. The appropriate level of payroll taxes for use in this proceeding is $6,811.

28. It is reasonable and appropriate to calculate regulatory fee expense using the regulatory fee rate of 0.13% effective July 1, 2019, pursuant to the Commission's June 18, 2019 Order issued in Docket No. M-100, Sub 142. The appropriate level of regulatory fee for use in this proceeding is $1,565.

29. It is reasonable and appropriate to use the current North Carolina corporate income tax rate of 2.50% to calculate Pluris Webb Creek's revenue requirement. The appropriate level of state income taxes for use in this proceeding is $7,990.

30. It is reasonable and appropriate to use the federal corporate income tax rate of 21.00% to calculate Pluris Webb Creek's revenue requirement. The appropriate level of federal income taxes for use in this proceeding is $65,439.

31. It is appropriate to calculate income taxes for ratemaking purposes based on the adjusted level of revenues and expenses and the tax rates for utility operations.

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

32. The cost of capital and revenue increase approved in this Order is intended to provide Pluris Webb Creek, through sound management, the opportunity to earn an overall rate of return of 6.28%. This overall rate of return is derived from applying an embedded cost of debt of 4.11%, and a rate of return on common equity of 8.98%, to a capital structure consisting of 55.32% long-term debt and 44.68% common equity.

33. An 8.98% rate of return on common equity for Pluris Webb Creek is just and reasonable in this general rate case.

34. A 44.68% equity and 55.32% debt ratio is a reasonable and appropriate capital structure for Pluris Webb Creek in this case.

35. A 4.11% cost of debt for Pluris Webb Creek is reasonable and appropriate for the purpose of this case.

36. The rate of return on common equity and capital structure approved by the Commission appropriately balances the benefits received by Pluris Webb Creek's customers from

Pluris Webb Creek's provision of safe, adequate, and reliable wastewater utility service with the difficulties that some of Pluris Webb Creek's customers may experience in paying the Company's increased rates.

37. The 8.98% rate of return on common equity and the 44.68% equity capital structure approved by the Commission balance Pluris Webb Creek's need to obtain equity and debt financing with its customers' need to pay the lowest possible rates.

38. The authorized levels of overall rate of return and rate of return on common equity set forth above are supported by competent, material, and substantial record evidence; are consistent with the requirements of N.C. Gen. Stat. § 62-133; and are fair to Pluris Webb Creek's customers generally and in light of the impact of changing economic conditions.

Revenue Requirement

39. The rate base method is the appropriate method to be used in this proceeding for determining fair and reasonable rates for sewer service as allowed by N.C.G.S. § 62-133.

40. The appropriate level of operating revenues under stipulated rates for use in this proceeding is $1,203,963, consisting of service revenues of $1,182,056 and miscellaneous revenues of $24,490, reduced by uncollectible accounts of $2,583.

41. Pluris Webb Creek's rates should be changed by amounts which, after all pro forma adjustments, will produce service revenues of $1,182,056. These rate increases will allow Pluris Webb Creek the opportunity to earn a 6.28% overall rate of return, which the Commission has found to be reasonable upon consideration of the findings in this Order.

42. The stipulated rates and charges listed below and included in Appendix A, attached to this Order, are just and reasonable and should be approved.

	Stipulated Rates
Monthly Residential Flat Rate:	$ 73.38 per unit
Monthly Commercial Metered Rates:	
Base charge, zero usage:	
<1" meter	$ 10.00
1" meter	$ 25.00
1.5 " meter	$ 50.00
2" meter	$ 80.00
3" meter	$ 250.00
Usage charge, per 1,000 gallons	$ 16.50

43. Pluris Webb Creek's current rates were authorized subject to true-up based on a final accounting of its emergency utility operations of the Webb Creek wastewater system and the subsequent granting of a certificate of public convenience and necessity (CPCN) with provisional interim rates. Pluris Webb Creek filed its final accounting as part of this rate case and should be allowed to recover from customers as rate base over time to mitigate rate impacts the amount of $202,877 under recovered during its time as emergency operator.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-6

General Matters

The evidence supporting these findings of fact is found in the verified 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. 7–12

The Joint Stipulation and Acceptance of Stipulation

The evidence supporting these findings of fact is found in the Joint Stipulation, the testimony of both Pluris Webb Creek's and the Public Staff's witnesses, and Joint Stipulation Exhibit I.

On October 9, 2020, Pluris Webb Creek and the Public Staff filed the Joint Stipulation, which resolves all issues in this proceeding between the Stipulating Parties. Pluris Webb Creek and the Public Staff are the only parties to this proceeding. Attached to the Joint Stipulation is Stipulation Exhibit 1, which demonstrates the impact of the Stipulating Parties' agreements on the calculation of Pluris Webb Creek's gross revenue for the test year ended December 31, 2019, updated to July 31, 2020, and adjusted for certain changes based upon circumstances occurring or becoming known through October 9, 2020.

Based upon the foregoing and the entire record herein, the Commission finds that the Joint Stipulation represents a negotiated settlement of all issues in this proceeding and that the provisions agreed to by the Stipulating Parties are reasonable and appropriate for purposes of this proceeding. In making this finding, the Commission gives substantial weight to the testimony of Pluris Webb Creek witnesses Gallarda and Winters, the affidavit and supporting exhibit of Public Staff witness Coleman, and the testimony and supporting exhibits of Public Staff witnesses Franklin and Lozier. The Commission finds that the resulting rates are just and reasonable to both Pluris Webb Creek and its ratepayers. In addition, the Commission finds that the provisions of the Joint Stipulation are just and reasonable to all parties to this proceeding and serve the public interest, and that it is appropriate to approve the Joint Stipulation in its entirety.

WATER AND SEWER – RATE INCREASE

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13–18

Customer Concerns and Service

The evidence supporting these findings of fact is found in the testimony of the public witnesses appearing at the hearing, the Application, the testimony of Public Staff witness Franklin, and the testimony and exhibits of Pluris Webb Creek witness Gallarda.

On April 27, 2020, Pluris filed an application for a general rate increase, which was verified by Pluris Webb Creek's Managing Member. In the Application, the Company states that as of the end of the test year ended December 31, 2019, Pluris Webb Creek served approximately 1,354 residential and eight commercial sewer customers in Onslow County, North Carolina.

In his prefiled testimony, Public Staff witness Franklin testifies that he reviewed approximately seven position statements from Pluris customers. He states that all of the customers expressed concern about the amount of the proposed rate increase; none of the customers had any service-related issues.

Six customers testified during the remote public hearing held Wednesday, September 23, 2020. All six customers expressed concern about the amount of the proposed rate increase, in particular relating to the scale of the new plant and the magnitude of the proposed rate increase. None of the public witnesses expressed any concerns regarding the quality of service provided by Pluris. The overall quality of service provided by Pluris is good, as supported by the Joint Stipulation.

In his prefiled testimony, Pluris Webb Creek witness Gallarda states that the Commission appointed Pluris Webb Creek as emergency operator of the Webb Creek wastewater system in August 2016 by the EO Order issued August 8, 2016. He further states that as detailed in the EO Order, and the Public Staff's Petition for Appointment of Emergency Operator and Approval of Rate Increase filed on August 3, 2016, in the EO Docket, there were numerous serious issues with the Webb Creek system. Witness Gallarda notes that the most significant issues concerned the condition of the plant, missing and non-operational equipment, ownership of system assets, outstanding liens, and serious environmental compliance issues with Webb Creek's operations.

Witness Gallarda next testifies that the majority of the Webb Creek system was more than 30 years old and due to years of neglect, much of it was beyond its practical design life. He also notes that lack of capital investment and periodic maintenance necessary to meet regulatory compliance contributed to the over 400 Notice of Violations (NOVs) issued to Webb Creek by North Carolina Department of Environmental Quality (DEQ). Witness Gallarda states that Pluris Webb Creek ultimately spent more than $900,000 over the next 2½ years in an effort to address issues in the Webb Creek SBR plant and collection system and the Company was able to achieve substantial compliance with the DEQ requirements. He states that as to the situation with the DEQ certifications necessary for military personnel to buy and sell homes in the Webb Creek service area, with assistance from Senator Thom Tillis' office, Pluris Webb Creek was able to work with the Veterans Administration and DEQ to enable military personnel to buy and sell homes during Pluris Webb Creek's tenure as emergency operator.

Witness Gallarda then testifies that Pluris Webb Creek acquired the WWTP, the collection systems and the land and assets that comprise the Webb Creek system through Onslow County's tax foreclosure proceedings. He states that although Pluris Webb Creek was able to achieve substantial compliance with DEQ's requirements within a few months of being appointed emergency operator as a result of the Company's infusion of significant capital to address many of the problems at the Webb Creek WWTP, there are continuing compliance issues that cannot be adequately addressed, as well as significant concerns with the integrity of the existing WWTP. Primary concerns include direct discharge from leaking tank vessels and the presence of enterococci in discharge effluent following treatment.

Witness Gallarda further testifies that Pluris Webb Creek has undertaken the construction, on the existing WWTP site, of a new MBR wastewater treatment plant with a 350,000 gpd treatment capacity. He further states that the new MBR plant is sized to serve the legacy Webb Creek service area, a nearby development known as The Pines, and the general vicinity.

In his prefiled testimony, Witness Franklin provides a brief history of Pluris Webb Creek and its relationship to Webb Creek, the prior franchise owner of the service area. He states that Webb Creek was the original developer-owned utility providing wastewater service in this area since the 1980s.[42] The owner-developer comingled development and utility property, which, due to financial problems, resulted in liens on property used to provide utility service. On August 8, 2016, in Docket No. W-864, Sub 11, the Commission issued its Order Appointing Emergency Operator, Approving Increased Rates, and Requiring Customer Notice, whereby Pluris Webb Creek was appointed emergency operator of Webb Creek's wastewater system. The Commission's Finding of Fact No. 12 in its August 8, 2016 Order provides additional context regarding the state of affairs, the plight of customers, and the wastewater system at that time:

> A real emergency exists regarding the Webb Creek wastewater utility system, as Webb Creek does not have and has no prospect of obtaining the funds for necessary operations, system replacements and upgrades, and is in material non-compliance with G.S. 143-215.1, its NPDES Permit, and its Collection Permit, and its customers are in imminent danger of losing adequate wastewater utility service.

In this proceeding, through his prefiled testimony witness Franklin testifies that Pluris Webb Creek was able to acquire ownership the property necessary to operate the wastewater system, and to establish reasonable compliance with state requirements. Witness Franklin further testifies that on March 26, 2019, in Docket Nos. W-864, Sub 11 and 14, and Docket No. W-1314, Sub 1, the Commission canceled the franchises of Webb Creek and granted franchises for the same service areas to Pluris Webb Creek. He noted that the Commission's Finding of Fact No. 1 from its March 26, 2019 Order states as follows:

> 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

[42] *See* Docket No. W-864.

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.

Witness Franklin further testifies that the Webb Creek WWTP also treats the wastewater of customers previously served by Pine Utilities, Inc., as the wastewater system of Pine Utilities, Inc., was transferred to Pluris Webb Creek pursuant to Commission Order issued on November 14, 2019, in Docket Nos. W-1314, Sub 0 and 2, and Docket No. W-822, Sub 3.

Witness Franklin next testifies that Pluris Webb Creek has built a new MBR WWTP to replace the old deteriorated WWTP. The new plant went into service on approximately June 16, 2020. Witness Franklin describes Pluris Webb Creek's wastewater system as consisting of a new 350,000 gallons per day MBR WWTP and a collection network comprised of approximately three miles of force main, twelve miles of gravity main, and eight duplex lift stations.

Witness Franklin also testifies that the Public Staff has made two recent visits to the Pluris Webb Creek WWTP and the Company's call center (owned and operated by its parent company, Pluris Holdings, LLC) located in Sneads Ferry. Witness Franklin states that on December 4, 2019, he and David Furr, Director of the Public Staff Water, Sewer, and Telephone Division accompanied by Messrs. Maurice Gallarda, Randy Hoffer, and Michael Gallant, representatives from Pluris Webb Creek, visited and visually inspected the then-operating WWTP built by the prior operator as well as the Pluris Webb Creek WWTP being constructed, and toured the call center. He notes that during the December 4, 2019 visit, the Public Staff observed the worsening condition of the then-operating aged WWTP and discussed with Pluris Webb Creek the improvements made by the Company since its appointment as emergency operator. Witness Franklin further testifies that on June 11, 2020 the Public Staff toured the new MBR WWTP, which was in operation after recently completing operational testing. He states that he observed that the MBR WWTP appears to be operating extremely well, including producing clear effluent.

Based upon the foregoing, and after careful review of the testimony of the customers at the public hearing and the Public Staff's engineering and service quality investigation, the Commission concludes that, consistent with the statutory requirements of N.C.G.S. § 62-131(b), the overall quality of service provided by Pluris Webb Creek is adequate, efficient, and reasonable.

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

Rate Base

The evidence supporting these findings of fact is found in the verified Application and the accompanying NCUC Form W-1, the testimony of Company witness Winters, the affidavit of Public Staff witness Coleman, the testimony of Public Staff witness Franklin, the Joint Stipulation, the EO docket, and the records of the Commission.

Stipulation Exhibit I, Schedule 2, provides as follows:

Item	Amount Per Application	Public Staff Adjustments	Amount Per Public Staff
Plant in service	$6,784,276	$0	$6,784,276
Accumulated depreciation	(242,905)	0	(242,905)
Net plant in service	6,541,371	0	6,541,371
Contributions in aid of constr.	(54,000)	0	(54,000)
Accumulated amortization – CIAC	1,026	0	1,026
Prepaid tap on fees	(128,898)	0	(128,898)
Customer deposits	(29,175)	0	(29,175)
Accum. def. income taxes	(164,156)	0	(164,156)
Cost free capital	0	(100,000)	(100,000)
Cash working capital	68,077	(626)	67,451
Average tax accruals	0	(1,362)	(1,362)
Original cost rate base	$6,234,245	($101,988)	$6,132,257

In Docket No. W-864, Sub 11 and Sub 14 and W-1314, Sub 1, the Commission concluded that

> "[g]iven 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.

Consequently, the Commission finds that it is appropriate to treat the $100,000 proceeds from the forfeiture of Webb Creek's bond security and previously disbursed to Pluris Webb Creek as cost-free capital and as a reduction to rate base in this proceeding, as agreed to by the Stipulating Parties.

Stipulation Exhibit I reflects the agreement between the Stipulating Parties concerning all components of rate base. Therefore, based on the evidence in the record, the Commission finds that the adjustments to rate base provided for in the Joint Stipulation are appropriate for use in this proceeding. Accordingly, the appropriate level of rate base for combined operations for use in this proceeding is as follows:

Item	Amount
Plant in service	$6,784,276
Accumulated depreciation	(242,905)
Net plant in service	6,541,371
Contributions in aid of construction	(54,000)
Accumulated amortization – CIAC	1,026
Prepaid tap on fees	(128,898)
Customer deposits	(29,175)
Accumulated deferred income taxes - ADIT	(164,156)
Cost free capital	(100,000)
Cash working capital	67,451
Average tax accruals	(1,362)
Original cost rate base	$6,132,257

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 21-22

Operating Revenues

The evidence supporting these findings of fact is found in the testimony of Pluris witness Winters and Public Staff witness Franklin, and the Affidavit of Public Staff witness Coleman. 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	Amount Per Application	Public Staff Adjustments	Amount Per Public Staff
Service revenues	$605,021	$1,571	$606,592
Miscellaneous revenues	24,490	0	24,490
Uncollectible accounts	(2,583)	0	(2,583)
Total operating revenues	$626,928	$1,571	$628,499

The adjustments are supported by the testimony of Public Staff witness Franklin, including Franklin Exhibit 2, and the affidavit and exhibit of Public Staff witness Coleman. Based on the Joint Stipulation and the revisions agreed upon in Stipulation Exhibit I, the Company does not dispute the Public Staff adjustment to reflect pro forma level of service revenues under present rates.

In his prefiled testimony, witness Franklin testifies that he calculated revenues based on the billing data provided by the Company for the test year ended December 31, 2019. He notes that the billing data showed an increase of approximately 20 residential customers in the second half of the test year. Witness Franklin further explains that there is little to no growth in the Pluris Webb Creek service area but due to the large military family presence in the area, the variations in the number of active customers is typically due to transfers and deployments. As a result, he states that he determined the number of active residential customers by taking the average number of active residential customers during the second half of the test year. He further testifies that during the test year, there was no change in the number of active commercial customers. Witness Franklin also states that he calculated the total consumption for the commercial customers for each meter size.

For reasons agreed to by the parties in the Joint Stipulation and as reflected in Findings of Fact 9-11, the Commission has found that the adjustment listed above is appropriate to be made to operating revenues under present rates in this proceeding. The Commission further finds that the Public Staff's adjustment to operating revenues under present rates stipulated by the parties are appropriate. 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	$606,592
Miscellaneous revenues	24,490
Uncollectible accounts	(2,583)
Total operating revenues	$628,499

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 23-25

Maintenance and General Expense

The evidence for these findings of fact is found in the verified Application and the accompanying NCUC Form W-1, the testimony of Pluris witness Winters and Public Staff witness Franklin, the Affidavit of Public Staff witness Coleman, and Stipulation Exhibit I.

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:

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WATER AND SEWER – RATE INCREASE

Item	Amount Per Application	Public Staff Adjustments	Amount Per Public Staff
Salaries and wages	$108,253	$0	$108,253
Employee benefits	23,339	0	23,339
Sludge removal expense	44,640	(6,000)	38,640
Purchased power	54,062	17,383	71,445
Chemicals	7,977	0	7,977
Materials and supplies (M&R)	15,758	(151)	15,607
Contract services - Engineering	0	0	0
Contract services - Accounting	0	0	0
Contract services - Legal	982	0	982
Contract serv. - Manage. Fees	128,732	0	128,732
Contract serv. - Direct utility fees	36,534	0	36,534
Contract services - Testing	31,208	(6,850)	24,358
Contract services - Other	6,719	0	6,719
Rent expense	0	0	0
Insurance – General Liability	142	0	142
Insurance – Workers Comp.	176	0	176
Insurance – Other	9,108	0	9,108
Miscellaneous expenses	50,595	0	50,595
Regulatory commission expense	17,000	0	17,000
Total O&M expenses	$535,225	$4,382	$539,607

The adjustments are supported by the testimony of Public Staff witness Franklin, and the Affidavit and Exhibit of Public Staff witness Coleman. In his prefiled testimony, Witness Franklin testifies that he removed $6,000 included by the Company for sludge removal expense because these amounts were incurred outside of the test year. Witness Franklin further testifies that he adjusted purchased power expense to reflect the increased power usage of the MBR plant as compared to the SBR plant. He next states that since the MBR plant went into service in June 2020, the Public Staff was provided the purchased power invoices for the months of July and August 2020. He further explains that while there is some fluctuation in WWTP power usage from month to month, the fluctuations are not seasonal and usage is relatively steady. He further testifies that the Public Staff used the July and August 2020 purchased power invoices provided by Pluris Webb Creek for the MBR WWTP and determined an average monthly purchased power expense amount. Thus, witness Franklin states that he calculated an increase to purchased power expense of $17,383. Witness Franklin also testifies that he adjusted materials and supplies expense to exclude an amount not incurred in the test year and amounts for which supporting documentation was not provided by the Company. Finally, Witness Franklin states that he adjusted testing fees to exclude testing performed outside of the test year and an amount of $6,250 that was proposed for by Pluris Webb Creek in its Application but later withdrawn in response to a Public Staff data request.

On the basis of the Joint Stipulation and revisions made by the Public Staff in the Affidavit of Public Staff Accountant Coleman Exhibit I, and Stipulation Exhibit I, the Company and the Public Staff are in agreement concerning all adjustments recommended by the Public Staff to maintenance and general expenses. The Commission finds that the uncontested adjustments to maintenance and general expenses recommended by the Public Staff are appropriate adjustments to be made in this proceeding.

WATER AND SEWER – RATE INCREASE

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
Salaries and wages	$108,253
Employee benefits	23,339
Sludge removal expense	38,640
Purchased power	71,445
Chemicals	7,977
Materials and supplies (M&R)	15,607
Contract services - Engineering	0
Contract services - Accounting	0
Contract services - Legal	982
Contract serv. - Manage. Fees	128,732
Contract serv. - Direct utility fees	36,534
Contract services - Testing	24,358
Contract services - Other	6,719
Rent expense	0
Insurance – General Liability	142
Insurance – Workers Comp.	176
Insurance – Other	9,108
Miscellaneous expenses	50,595
Regulatory commission expense	17,000
Total O&M expenses	$539,607

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26-31

Depreciation, Amortization Expense, Taxes and Regulatory Fee

The evidence supporting these findings of fact is found in the verified Application and the accompanying NCUC Form W-1, the testimony of Company witness Winters the testimony of Public Staff witness Franklin, the affidavit of Public Staff witness Coleman, and Stipulation Exhibit I.

The following table summarizes the differences between the Company's level of depreciation and amortization expenses, taxes and regulatory fee from its Application and the amounts recommended by the Public Staff:

Item	Amount Per Application	Public Staff Adjustments	Amount Per Public Staff
Depreciation expense	$197,847	$0	$197,847
Amortization of CIAC	(898)	0	(898)
Franchise and other taxes	0	0	0
Property taxes	0	0	0
Payroll taxes	6,811	0	6,811
Regulatory fee	850	(33)	817
State income tax	0	0	0
Federal income tax	0	0	0
Total depreciation and taxes	$204,610	($33)	$204,577

With respect to Pluris Webb Creek's regulatory fee expense, in light of the Joint Stipulation and revisions recommended by the Public Staff in its witnesses' testimony and reflected in Stipulation Exhibit I, the Company does not dispute the adjustment recommended by the Public Staff to regulatory fee expense. The Commission finds that the adjustment recommended by the Public Staff to regulatory fee expense, which is not contested, is an appropriate adjustment to be made to operating revenue deductions in this proceeding. Based on the foregoing, the Commission concludes that the appropriate level of depreciation, amortization expense, taxes, and regulatory fee for use in this proceeding is as follows:

Item	Amount
Depreciation expense	$197,847
Amortization of CIAC	(898)
Franchise and other taxes	0
Property taxes	0
Payroll taxes	6,811
Regulatory fee	817
State income tax	0
Federal income tax	0
Total depreciation and taxes	$204,577

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 32 - 38

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

The evidence supporting these findings of fact is found in the verified Application and the accompanying NCUC Form W-1, the testimony and exhibits of Company witness Gallarda, the testimony and exhibits of Public Staff witness Lozier, and the Joint Stipulation.

In its Application, the Company requests approval for its rates to be set using a rate of return on common equity of 9.60%, which would yield an overall rate of return on rate base for Pluris Webb Creek of 6.56%. In his prefiled testimony, Witness Gallarda testifies that these rates would yield a rate of return on rate base for the Company that would be less than what the Commission set in recent rate cases for Carolina Water Service, Inc. of North Carolina (Docket

No. W-354, Sub 364) and for Aqua North Carolina, Inc. (Docket No. W-218, Sub 497). Witness Gallarda further testifies that Pluris Webb Creek advocated for this approach to avoid increasing the amount of rate case expense that will be passed through to Pluris Webb Creek's ratepayers by employing an expert witness to address this issue in this docket. Witness Gallarda also testifies that the Company's current capital structure is 56% debt and 44% equity.

In his prefiled testimony, Public Staff witness Lozier recommends an overall rate of return of 6.29%, based on the Company's capital structure as of June 30, 2020, that is composed of 55.32% long-term debt, 44.68% common equity. This recommended overall rate of return recommendation is based on a cost rate of long-term debt of 4.11%, and a cost rate for common equity of 9.00%.

In the Joint Stipulation, the Public Staff and the Company agree on the capital structure of 55.32% long-term debt and 44.68% common equity and a cost of long-term debt of 4.11%, and reached a compromise on the rate of return on common equity solely for purposes of this settlement. In consideration of several factors, including the impacts of the Coronavirus pandemic on customers and changing economic conditions, the Stipulating Parties further agree to make use of a rate of return on common equity of 8.98% in setting rates in this proceeding. The Stipulating Parties note that their compromise on this issue yields a rate of return on equity that is lower than the 9.50% rate of return on equity that the Commission found to be appropriate in a recent rate case involving Carolina Water Service (Docket No. W-354, Sub 364), where this issue was vigorously litigated.

Having carefully reviewed the evidence related to the stipulated capital structure, the rate of return on common equity and the overall rate of return, the Commission finds that the stipulated and agreed-upon capital structure of 55.32% debt and 44.68% equity, the long-term debt cost rate of 4.11%, a return on common equity of 8.98%, and the opportunity to earn an overall rate of return of 6.28%, is just and reasonable. The Commission further finds that this return will allow the Company, by sound management, the opportunity to produce a fair return for its shareholders, to maintain its facilities and services in accordance with the reasonable requirements of customers, and to compete in the market for capital on terms that are reasonable and fair to its customers and to its shareholders.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 39-42

Revenue Requirement

The evidence supporting these findings of fact is found in testimony of Public Staff witnesses Franklin and Lozier, the Affidavit of witness Coleman, and in Stipulation Exhibit I.

In her affidavit, Public Staff affiant Coleman states that she used the rate base method pursuant to N.C.G.S. § 62-133, to calculate the Public Staff's recommended revenue requirement in this proceeding. Through the Joint Stipulation, the Stipulating Parties agree that Pluris Webb Creek's rates should be adjusted by amounts which, after all pro forma adjustments, will produce revenues of $1,182,056. These rate increases will allow Pluris Webb Creek the opportunity to earn a 6.28% overall rate of return, as stipulated. The stipulated rate increases represent an increase of

$575,464 or 105% in total sewer operating revenues. Under the stipulated rates, the monthly flat sewer rate for a residential customer would increase from $37.69 to $73.38, or 95%.

Based upon the evidence of record, the Commission concludes that the stipulated rates and charges are just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 43

Final Accounting of Provisional Rates

The evidence supporting this finding of fact is found in testimony of Company witness Winters, the EO Docket, and the records of the Commission.

Pluris Webb Creek's current rates were authorized subject to true-up based on a final accounting of its emergency utility operations of the Webb Creek wastewater system and the subsequent granting of a CPCN with provisional interim rates. Pluris Webb Creek filed its final accounting as part of this rate case to demonstrate the investment of $900,000 to address issues and problems with the system during its time as emergency operator. Pluris states that it is currently earning a 2.41% return and is unable to cover its operating costs and earn a reasonable return on its investment. As discussed in witness Winters' prefiled testimony the final accounting provided with the Application shows that Pluris Webb Creek under-recovered $202,877 during its time as emergency operator. Witness Winters states that Pluris Webb Creek proposes to recover this under recovery as rate base over time to mitigate rate impacts. Pluris Webb Creek provided its proposed adjustment in Pluris Schedule 10b filed with the Application and updated on August 24, 2020, to reflect its updates to rate base as of July 31, 2020. Stipulation Exhibit I, Schedule 2, Original Cost Rate Base, includes the Company's $202,877 adjustment to rate base in this proceeding to reflect the calculated under recovery.

The Commission concludes that the adjustment recommended by Pluris Webb Creek in this proceeding to account for the under recovered $202,277 during the Company's time as emergency operator, which has been included by the Stipulating Parties in Stipulation Exhibit I, Schedule 2, is an appropriate adjustment to be made in this proceeding and should be accepted as the required final accounting of the provisional rates charged by Pluris Webb Creek.

IT IS, THEREFORE, ORDERED as follows:

1. That the Joint Stipulation is incorporated herein by reference and is hereby approved in its entirety;

2. That the Joint Stipulation and the parts of this Order pertaining to the contents of the Joint Stipulation shall not be cited or treated as precedent in future proceedings;

3. That the Schedule of Rates, attached hereto as Appendix A, is hereby approved and deemed to be filed with the Commission pursuant to N.C.G.S. § 62-138, and the rates set forth therein are hereby authorized to become effective for service rendered on and after the date of this Order;

4. That the Notice to Customers, attached hereto as Appendix B, 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; and

5. That Pluris Webb Creek shall file the attached Certificate of Service, properly signed and notarized, not later than 45 days after the issuance of this Order.

ISSUED BY ORDER OF THE COMMISSION
This the 17th day of December, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Joann R. Snyder, Deputy Clerk

APPENDIX A
PAGE 1 OF 3

SCHEDULE OF RATES

for

PLURIS WEBB CREEK, LLC

for providing sewer utility service

in

ALL OF ITS SERVICE AREAS SERVED BY THE
PLURIS WEBB CREEK WASTEWATER UTILITY SYSTEM
Onslow County, North Carolina

Monthly Residential Flat Rate:	$ 73.38 per unit
Monthly Commercial Metered Rates:	
Base charge, zero usage:	
<1" meter	$ 10.00
1" meter	$ 25.00
1.6 " meter	$ 50.00
2" meter	$ 80.00
3" meter	$ 250.00
Usage charge, per 1,000 gallons	$ 16.50

Customers who ask to be reconnected at the same service location within nine months of disconnection, will be charged the entire flat rate or base monthly charge for the periods they were disconnected.

Reconnection Charge:

If sewer service cut off by utility for good cause:	Actual cost

(Customers shall be given a written estimate of the actual costs prior to disconnection. An actual invoice of the costs shall be given to the customer following disconnection.

APPENDIX A
PAGE 2 OF 3

Connection Fee:

Residential:	$3,200 per SFE
Each additional bedroom beyond three per residence	$1,607
Commercial:	$3,200 per SFE

A single family equivalent (SFE) for a detached single family residence is three or less bedrooms.

A SFE for a commercial connection is determined by taking the design flow capacity for each non-residential commercial customer, as set forth in Administrative Code 15A NCAC 2 T .0114, and dividing the design flow by 360.

Road Bore Charge:

The road bore charge shall be the actual costs of labor and materials for the road boring. This charge shall be in addition to the connection fee. The customer may, choose to have a licensed contractor perform the road bore at the customer's sole expense, provided that the road bore and all related work shall be in accordance with Pluris's standards.

The above connection fees, and Road Bore Charge do not apply to future connections for which prepaid connection fees have been received prior to the date of this Order.

WATER AND SEWER – RATE INCREASE

Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Return Check Fee:	$25.00
Billing Frequency:	
Flat Rate Residential Customers	Shall be monthly for service in advance
Metered Commercial Customers	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 the billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1314, Sub 4, on this the 17th day of December, 2020.

APPENDIX B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

NOTICE TO CUSTOMERS
DOCKET NO. W-1314, SUB 4
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Notice is hereby given that the North Carolina Utilities Commission has issued an Order authorizing Pluris Webb Creek, LLC, to increase sewer rates in its service areas in Onslow County, North Carolina. The new approved rates are as follows:

Monthly Residential Flat Rate:	$ 73.38 per unit
Monthly Commercial Metered Rates:	
Base charge, zero usage:	
<1" meter	$ 10.00
1" meter	$ 25.00
1.5 " meter	$ 50.00
2" meter	$ 80.00
3" meter	$ 250.00
Usage charge, per 1,000 gallons	$ 16.50

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of December, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Joann R. Snyder, Deputy Clerk

WATER AND SEWER – RATE INCREASE

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 No. W-1314, Sub 4 and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ___________________, 2020.

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 _______________, 2020, in Docket No. W-1314, Sub 4.

Witness my hand and notarial seal, this the ______ day of ___________________, 2020.

____
Notary Public

____
Printed or Typed Name

(SEAL) My Commission Expires: ______________________________________
Date

DOCKET NO. W-1305, SUB 12

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Pluris Hampstead, LLC, 5950 Berkshire Lane, Suite 800, Dallas, Texas, 75225 for Authority to Increase Rates for Sewer Utility Service in All of Its Service Areas in Pender County, North Carolina	) ORDER APPROVING AGREEMENT AND STIPULATION OF SETTLEMENT, GRANTING PARTIAL RATE INCREASE, AND REQUIRING CUSTOMER NOTICE

HEARD: Monday, August 17, 2020, at 7:00 p.m., remotely via Webex.

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

APPEARANCES:

For Pluris Hampstead, LLC:

Daniel C. Higgins, Burns, Day & Presnell, P.A., Post Office Box 10867, Raleigh, North Carolina 27605

For the Using and Consuming Public:

William E. H. Creech, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On November 21, 2019, in the above-captioned docket, Pluris Hampstead, LLC, (Pluris Hampstead or Company) filed with the North Carolina Utilities Commission (Commission or NCUC) pursuant to Commission Rule R1-17(a) notice of its intent to file an application for a general rate case.

On January 22, 2020, the Company filed its verified Application for a general rate increase for sewer utility service rates in all its service areas in Pender County, North Carolina. Along with its Application, Pluris Hampstead prefiled the direct testimony of Maurice W. Gallarda, PE, Managing Member, Pluris Holdings, LLC, and Daniel J. Winters, Chief Financial Officer, Pluris Holdings, LLC.

On February 17, 2020, the Commission issued its Order Establishing General Rate Case and Suspending Rates.

On March 18, 2020, the Commission issued an Order Scheduling Hearings, Establishing Discovery Guidelines, and Requiring Customer Notice.

On April 15, 2020, Pluris Hampstead filed an Update to its operating expenses and rate base.

On June 2, 2020, the Commission issued an Order Canceling Public Witness Hearing in light of the COVID-19 pandemic.

On July 1, 2020, the Commission issued an Order Scheduling Hearings and Requiring Customer Notice.

On July 14, 2020, the Public Staff prefiled the testimony and exhibits of Public Staff witnesses Gina Y. Casselberry, Utilities Engineer, Water, Sewer, and Telephone Division; Jenny Li, Staff Accountant, Accounting Division; and Calvin Craig, III, Financial Analyst, Economic Research Division.

On August 17, 2020, a public hearing was conducted via Webex; testimony from six sworn witnesses was heard by the Commission.

On August 19, 2020, the Public Staff and Pluris Hampstead filed an Agreement and Stipulation of Settlement (Stipulation), which reflected the parties' agreement on settlement.

On September 2, 2020, the Commission issued an Order Rescheduling Expert Witness Hearing and Requiring Verified Information.

On September 4, 2020, the Public Staff filed the Supplemental Testimony of Public Staff witness Casselberry.

On September 9 and 10, 2020, the Public Staff and Pluris Hampstead filed their respective verified response (Verified Responses) to the questions posed to them in the Commission's September 2, 2020 Order.

On September 16, 2020, the Public Staff and Pluris Hampstead filed a Joint Response indicating that neither had any comments on the responses filed by the other party to the questions posed by the Commission in its September 2, 2020, Order.

On September 16, 2020, the Commission issued an Order Cancelling Expert Witness Hearing and Admitting Evidence into the Record.

The Public Staff and Pluris Hampstead filed a Joint Proposed Order on October 16, 2020.

On the basis of the Application, the testimony, the Stipulation, the Verified Responses, and other evidence of record, the Commission now makes the following:

WATER AND SEWER – RATE INCREASE

FINDINGS OF FACT

1. Pluris Hampstead is a limited liability company duly organized under the laws of and authorized to do business in the State of North Carolina. Pluris Hampstead is a franchised public utility providing sewer utility service to customers in North Carolina.

2. Pluris Hampstead is properly before the Commission, pursuant to Chapter 62 of the General Statutes of North Carolina, for determination of the justness and reasonableness of its proposed rates and charges for its wastewater services provided in its Commission-assigned service areas.

3. The appropriate test year for purposes of establishing rates in this docket is the 12-month period ended September 30, 2019, updated to March 31, 2020.

4. Pluris Hampstead's present rates for sewer service have been in effect since November, 2015, pursuant to the Commission's Order dated November 5, 2015, in Docket No. W-1305, Sub 0.

5. Pluris Hampstead's present and proposed rates are as follows:

	Present Rates	Proposed Rates
Monthly Residential Flat Rate:	\$ 63.95	\$ 84.42 (1)
(1) All residential flat rate customers		
Monthly Commercial Metered Rates:		
Base charge, zero usage (minimum charge)		
< 1"	\$ 25.24	\$ 10.00
1"	\$ 25.24	\$ 25.00
1.5"	\$ 25.24	\$ 50.00
2"	\$ 25.24	\$ 80.00
4"	\$ 25.24	\$250.00
6"	\$ 25.24	\$500.00
Usage charge, per 1,000 gallons	\$ 9.68	\$ 16.50

6. As of the end of the updated test year period, March 31, 2020, Pluris Hampstead served approximately 639 residential flat rate sewer customers and 59 metered commercial sewer customers in its service areas in Pender County, North Carolina. The Public Staff reclassified 203 residential flat rate customers from Sparrows Bend Apartments to ten 2-inch metered commercial customers, resulting in Pluris Hampstead serving 436 flat rate residential customers and 69 metered commercial customers. Pluris Hampstead and the Public Staff agree that Sparrows Bend Apartments should be reclassified as a commercial customer with ten 2-inch meters.

The Stipulation

7. The Stipulation is the subject of the agreement between the Public Staff and Pluris Hampstead (Stipulating Parties), who are the only parties to this docket.

8. The Stipulation resolves all matters in controversy in this docket as between these two parties to the case.

Acceptance of Stipulation

9. The revenue requirement agreed upon in the Stipulation will result in just and reasonable rates.

10. The provisions of the Stipulation are just and reasonable to all parties to this proceeding, as well as Pluris Hampstead's ratepaying customers, and serve the public interest.

11. It is appropriate to approve the Stipulation in its entirety.

Customer Concerns and Service

12. A total of six customers testified at the public hearing on August 17, 2020. In general, the public witnesses objected to the magnitude of the proposed rate increase, with some voicing concern regarding flat rate residential sewer rates. No customers voiced any complaint regarding the quality of the service provided by Pluris Hampstead.

13. The overall quality of service provided by Pluris Hampstead is good.

Rate Base

14. The appropriate level of rate base used and useful in providing sewer utility service is $1,999,795 for Pluris Hampstead's operations, consisting of the following components:

Item	Amount
Plant in service	$8,272,634
Accumulated depreciation	(840,214)
Net plant in service	7,432,419
Cash working capital	57,471
Contributions in aid of construction (CIAC)	(1,757,964)
Accumulated amortization	99,253
Prepaid tap on fees	(3,453,160)

Item	Amount
Customer deposits	(20,750)
Accumulated deferred income taxes (ADIT)	(356,023)
Average tax accruals	(1,451)
Original cost rate base	$1,999,795

Operating Revenues

15. The appropriate level of operating revenues under present rates for use in this proceeding is $664,188, consisting of service revenues of $648,647 and miscellaneous revenues of $17,684, reduced by uncollectible accounts of $2,143.

16. Pluris Hampstead requested an increase in rates that would produce $266,278 in additional total operating revenues after Public Staff adjustments, an increase of 40% over present annual total operating revenues.

Maintenance and General Expense

17. The appropriate level of operation and maintenance expense for Pluris Hampstead's operations for use in this proceeding is $459,771.

18. It is appropriate for Pluris Hampstead to recover total rate case expenses of $91,883 related to the current proceeding which is comprised of $18,108 in legal fees, $1,500 in contract labor, $67,275 in capitalized labor, and $5,000 in postage and printing to mail customer notices, the rate case filing fee, and miscellaneous expenses.

19. It is appropriate to amortize the total rate case expenses for the current proceeding over five years, resulting in an annual level of rate case expense of $18,377, as agreed to by the Stipulating Parties.

Depreciation, Amortization Expense, Regulatory Fee, and Taxes

20. The appropriate level of depreciation expense for use in this proceeding is $240,118 and the appropriate level of amortization of CIAC expense for use in this proceeding is ($28,207).

21. The appropriate level of payroll taxes for use in this proceeding is $7,257.

22. It is reasonable and appropriate to calculate regulatory fee expense using the regulatory fee rate of 0.13% effective July 1, 2019, pursuant to the Commission's June 18, 2019 Order issued in Docket No. M-100, Sub 142. The appropriate level of regulatory fee for use in this proceeding is $1,084.

23. It is reasonable and appropriate to use the current North Carolina corporate income tax rate of 2.50% to calculate Pluris Hampstead's revenue requirement. The appropriate level of state income taxes for use in this proceeding is $2,583.

24. It is reasonable and appropriate to use the federal corporate income tax rate of 21.00% to calculate Pluris Hampstead's revenue requirement. The appropriate level of federal income taxes for use in this proceeding is $21,157.

25. It is appropriate to calculate income taxes for ratemaking purposes based on the adjusted level of revenues and expenses and the tax rates for utility operations.

Reporting Requirements

26. It is appropriate for Pluris Hampstead to file with the Commission monthly progress reports on the status of acquisition of lift stations and/or mains needed for the seven pending applications identified in Casselberry Exhibit No.1 to the direct testimony of Public Staff witness Casselberry, as stipulated.

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

27. The cost of capital and revenue increase approved in this Order is intended to provide Pluris Hampstead, through sound management, the opportunity to earn an overall rate of return of 6.49%. This overall rate of return is derived from applying an embedded cost of debt of 4.35%, and a rate of return on common equity of 9.40%, to a capital structure consisting of 57.66% long-term debt and 42.34% common equity.

28. A 9.40% rate of return on common equity for Pluris Hampstead is just and reasonable in this general rate case.

29. A 42.34% equity and 57.66% debt ratio is a reasonable and appropriate capital structure for Pluris Hampstead in this case.

30. A 4.35% cost of debt for Pluris Hampstead is reasonable and appropriate for the purpose of this case.

31. The rate of return on common equity and capital structure approved by the Commission appropriately balances the benefits received by Pluris Hampstead's customers from Pluris Hampstead's provision of safe, adequate, and reliable wastewater utility service with the difficulties that some of Pluris Hampstead's customers may experience in paying the Company's increased rates.

32. The 9.40% rate of return on common equity and the 42.34% equity capital structure approved by the Commission balance Pluris Hampstead's need to obtain equity and debt financing with its customers' need to pay the lowest possible rates.

33. The authorized levels of overall rate of return and the rate of return on common equity set forth above are supported by competent, material, and substantial record evidence; are consistent with the requirements of N.C. Gen. Stat. § 62-133; and are fair to Pluris Hampstead's customers generally and in light of the impact of changing economic conditions.

Revenue Requirement

34. The rate base method is the appropriate method to be used in this proceeding for determining fair and reasonable rates for sewer service as allowed by N.C.G.S. § 62-133.

35. Pluris Hampstead's rates should be adjusted by amounts which, after all pro forma adjustments, will produce revenues of $833,512. These rate increases will allow Pluris Hampstead the opportunity to earn a 6.49% overall rate of return, which the Commission has found to be reasonable upon consideration of the findings in this Order.

36. The rate increases approved herein represent an increase of $169,324 or 25.5% in total sewer operating revenues.

37. The stipulated rates and charges listed below and included in Appendix A, attached hereto, are just and reasonable and should be approved.

	Stipulated Rates
Monthly Residential Flat Rate:	$ 82.50 (1)

(1) All residential flat rate customers

Monthly Commercial Metered Rates:

Base charge, zero usage (minimum charge)

< 1"	$ 23.50
1"	$ 58.75
1.5"	$ 117.50
2"	$ 188.00
4"	$ 587.00
6"	$1,175.00

Usage charge, per 1,000 gallons $ 16.50

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-5

General Matters

The evidence supporting these findings of fact is found in the verified 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 FINDING OF FACT NO. 6

Sparrows Bend Apartments

The evidence supporting this finding of fact is found in the verified Application and the accompanying NCUC Form W-1, the testimony and exhibits of Public Staff witness Casselberry, the Verified Responses of the Public Staff and Pluris Hampstead, and the entire record in this proceeding.

In its application, Pluris Hampstead classified the 203 customers located in Sparrow Bend Apartments as residential customers and bills each apartment unit its currently approved residential flat sewer rate.

In her prefiled testimony and exhibits, Public Staff witness Casselberry reclassified the 203 apartment units in Sparrows Bend Apartments from residential customers to ten 2-inch metered commercial customers. In her Verified Response to the Commission, witness Casselberry states that she made this adjustment for the following reasons:

(1) Pluris Hampstead has no means to disconnect individual apartment units for non-payment of sewer utility service. It does not own water meters providing service to the units, and it does not own sewer discharge piping at appropriate locations to disconnect individual units for non-payment. Any bad debt would ultimately be passed on to other Pluris Hampstead customers through general rate case proceedings.

(2) Through the review of resale applications before the Commission, it can easily be observed that most water/sewer utilities in the state charge the apartment complexes as their customers, not the individual apartment units.

(3) This change makes a metered sewer rate possible, which is more equitable than a flat rate, especially considering Sparrows Bend Apartments has many one bedroom apartments.

Further, witness Casselberry explains that had Pluris Hampstead filed the application for a certificate of public convenience and necessity prior to charging each individual unit the flat residential rate, the Public Staff would have recommended a commercial rate for Sparrows Bend Apartments, based on the size of the meters, and the Public Staff would have advised the Company to work with the owner of Sparrows Bend Apartments to obtain a certificate of authority to resell sewer service, especially given that the owner has been granted a certificate of authority for water service.

In its Verified Response to the Commission, Pluris Hampstead states that the Company agrees with the Public Staff's reclassification of the 203 customers located in Sparrows Bend Apartments from residential to ten 2-inch metered commercial customers. Pluris Hampstead further states that on a going forward basis the Company will bill the owner of Sparrows Bend Apartments as a metered commercial customer utilizing water consumption as the basis for billing the sewer utility service. Pluris Hampstead indicated that Pender County Utilities (PCU) would provide the monthly water meter readings from the 10 master meters for Sparrows Bend Apartments in order for Pluris Hampstead to bill the owner of the apartment complex for sewer service based on master metered water consumption. Pluris Hampstead notes that PCU's current monthly charge for providing that meter reading data is $2 per meter. Pluris Hampstead maintains that the principal concern regarding Sparrows Bend Apartments is that it is a multifamily property and thus the utility does not own the facilities running to each apartment. Pluris Hampstead notes that because the utility does not own or control all the facilities necessary to provide the utility service, the Company is not able to discontinue service to individual apartments in the event of non-payment.

Based upon the foregoing and the entire record herein, the Commission concludes that it is reasonable and appropriate to reclassify the 203 apartment units in Sparrows Bend Apartments from residential customers to ten 2-inch metered commercial customers as recommended by Public Staff witness Casselberry, agreed to by Pluris Hampstead, and reflected in Stipulation Exhibit II.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7–11

The Stipulation and Acceptance of Stipulation

The evidence supporting these findings of fact is found in the Stipulation; the testimony of both Pluris Hampstead's and the Public Staff's witnesses, Stipulation Exhibits I and II, and the filed Responses of Pluris Hampstead and the Public Staff to the Commission's Order Rescheduling Expert Witness Hearing and Requiring Verified Information.

On August 19, 2020, Pluris Hampstead and the Public Staff filed the Stipulation. Pluris Hampstead and the Public Staff are the only parties to this proceeding, and the Stipulation resolves all issues between the Stipulating Parties in this proceeding. Attached to the Stipulation is Stipulation Exhibit I, which demonstrates the impact of the Stipulating Parties' agreements on the calculation of Pluris Hampstead's gross revenues for the test year ended September 30, 2019, updated to March 31, 2020:

Based upon the foregoing and the entire record herein, the Commission finds that the Stipulation represents a negotiated settlement of all issues in this proceeding and that the provisions agreed to by the Stipulating Parties are reasonable and appropriate for the purpose of this proceeding. In making this finding, the Commission gives substantial weight to the testimony of Pluris Hampstead witnesses Gallarda and Winters, and the testimony and supporting exhibits of Public Staff witnesses Casselberry, Li, and Craig. The Commission finds that the resulting rates are just and reasonable to both Pluris Hampstead 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. 12–13

Customer Concerns and Service

The evidence supporting these findings of fact is found in the testimony of the public witnesses appearing at the hearings, in the supplemental testimony of Public Staff witness Casselberry, in the testimony and exhibits of Pluris Hampstead witness Gallarda, and in the Verified Responses filed by the Stipulating Parties filed in response to the Commission's Order.

Public Staff witness Casselberry testified that she reviewed approximately seven position statements from Pluris Hampstead customers. All of the customers objected to the magnitude of the proposed rate increase, but none of the customers had any service-related complaints.

Six customers testified during the remote public hearing held Monday, August 17, 2020; all six customers were opposed the magnitude of the proposed rate increase. None of the public witnesses had any service complaints, and several of the public witnesses stated that they were pleased with Pluris Hampstead's quick response time when concerns did arise.

On August 31, 2020, Pluris Hampstead filed a letter with the Commission in response to Ordering Paragraph No. 7 of the Order Rescheduling Hearings and Requiring Customer Notice issued on July 1, 2020, that while the six customers who testified at the public hearing complained about the proposed rate increase, there were not customer service or service quality complaints made about the service provided by Pluris Hampstead.

Witness Casselberry testified that based on her review of the position statements and the testimony of the public witnesses, and as stated in the Verified Response of the Public Staff, it is the Public Staff's opinion that the overall quality of service provided by Pluris Hampstead is good.

Pluris Hampstead witness Gallarda testifies that Pluris Hampstead owns and operates a wastewater only collection and treatment system consisting of an existing membrane bio-reactor (MBR) wastewater treatment plant (WWTP) with a 500,000 gallon per day (gpd) footprint currently capable of treating 250,000 gpd, and two high rate infiltration basins, located in Hampstead, North Carolina. He notes that the MBR plant was operational as of April 2016. Witness Gallarda states that Pluris Hampstead also has an approximately 11.5 mile force main running north along the US Highway 17 corridor in Pender County beginning at the New Hanover/Pender County line. Witness Gallarda further states that Pluris Hampstead's wastewater treatment system also includes collection infrastructure, duplex lift stations, and a new lift station midway along the force main. Witness Gallarda notes that one of the reasons Pluris Hampstead is seeking the requested rate increase is due to the recent installation of the new lift station at a cost of approximately $253,000. He testifies that Pluris Hampstead provides wastewater service to customers in the southeastern coastal area of Pender County, including about a dozen residential developments, a number of commercial locations, and Topsail High School, Topsail Middle School, and Topsail Elementary School.

In her prefiled testimony, witness Casselberry states that Pluris Hampstead's sewer force main begins at the New Hanover/Pender County line and runs north along Highway 17 in Hampstead, North Carolina for approximately 11.5 miles. She further states that the 250,000 gpd WWTP and high rate infiltration system is located at the southern end. Witness Casselberry states that there are nine duplex lift stations and a new regional lift station, which was installed at the midway point to help eliminate emergency backup issues in the force main caused by elevated pressure.

In her supplemental testimony, witness Casselberry testifies that on August 12, 2020, she inspected Pluris Hampstead's facility with Maurice Gallarda, Managing Member and Principal Engineer, Randy Hoffer, North Carolina Regional Manager, and Michael Gallant, PE. She observed that the WWTP is in very good condition and appears to be operating efficiently and effectively. Witness Casselberry notes that the back-up generator was in place and operational. She describes the effluent as being "crystal clear". She states that the two high-rate infiltration basins were operating effectively with eight to ten feet of freeboard. She observed that the groundwater storage pond is well maintained, including the vegetation that surrounds the pond. She opines that the wastewater facility is well maintained and working effectively.

Based upon the foregoing, and after careful review of the testimony of the customers at the public hearing, the Public Staff's engineering and service quality investigation, and the Verified Responses of Pluris Hampstead and the Public Staff, and the entire record, the Commission concludes that, consistent with the statutory requirements of N.C.G.S. § 62-131(b), the overall quality of service provided by Pluris Hampstead is adequate, efficient, and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

Rate Base

The evidence supporting this finding of fact is found in the verified Application and the accompanying NCUC Form W-1, the testimony of Pluris Hampstead witness Winters, the testimony of Public Staff witnesses Casselberry and Li, the Stipulation, and Stipulation Exhibit I.

Stipulation Exhibit I, Schedule 2 provides as follows:

Item	Company per Application	Public Staff Adjustments	Amount per Public Staff
Plant in service	$9,574,826	($1,302,192)	$8,272,634
Accumulated depreciation	(941,667)	101,453	(840,214)
Net plant in service	8,633,159	(1,200,739)	7,432,419
Contributions in aid of construction (CIAC)	(1,757,964)	0	(1,757,964)
Accumulated amortization of CIAC	99,253	0	99,253
Prepaid tap on fees	(3,453,160)	0	(3,453,160)
Customer deposits	(20,750)	0	(20,750)
Accumulated deferred income taxes (ADIT)	(356,023)	0	(356,023)
Cash working capital	59,040	(1,569)	57,471
Average tax accruals	0	(1,451)	(1,451)
Original cost rate base	$3,203,555	($1,203,759)	$1,999,795

WATER AND SEWER – RATE INCREASE

Pluris Hampstead filed its application using a 12-month test year ending September 30, 2019. The Public Staff updated the test year to reflect customer growth and plant in service for the 12-months ending March 31, 2020.

In his prefiled testimony, Pluris Hampstead witness Winters testifies that he removed $1,463,896 from plant, which represents 50% of the original cost of the 11.5 mile force main. He states that this adjustment is consistent with the agreement Pluris Hampstead reached with the Public Staff when the Company's initial (and current) rates were established in 2015 in Docket No. W-1305, Sub 0, that such an adjustment would be made with Pluris Hampstead reserving the right to request this amount be included in rate base in the future when it is deemed to be used and useful. Witness Winters also decreased accumulated depreciation as a result of his adjustment to plant to remove 50% of the original cost of the force main.

Public Staff witness Casselberry testifies that Pluris Hampstead's general rate case filing includes an excess capacity adjustment of 50% applied to sewer force mains. The Public Staff recommends an additional excess capacity adjustment of 38.80% for the WWTP and infiltration basins. Witness Casselberry maintains that the excess capacity adjustment removes from rate base a percentage of the plant and accumulated depreciation related to excess capacity in overbuilt plant. She notes that the Public Staff does not recommend excess capacity adjustments for all overbuilt plants. Witness Casselberry explains that commonly, the developer of a system bears a majority of the initial cost and risk associated with plant infrastructure to serve future projected growth. The initial construction is fully contributed by the developer to the utility. Witness Casselberry testifies that for the Pluris Hampstead sewer system, developers did not contribute the WWTP and infiltration basins, and Pluris Hampstead took on avoidable amounts of cost and risk from developers. Witness Casselberry maintains that without an excess capacity adjustment, present customers would pay for an unfair and disproportionally high amount for plant to serve potential future customers.

Witness Casselberry testifies that Pluris Hampstead currently has installed infrastructure to treat 500,000 gpd, except for the membrane set for the final 250,000 gpd capacity. She explains that these are not yet installed because they are not needed to treat current sewage flow and would be subject to damage and deterioration while not in service. She notes that the maximum daily sewage flow through the WWTP during the test year was 150,692 gallons.

Witness Casselberry contends that there is a history of calculating excess capacity adjustments for sewer treatment plants that can be found in numerous general rate case proceedings for Carolina Water Service, Inc. of North Carolina (CWSNC) and Aqua North Carolina, Inc. (Aqua). The Commission's previous orders regarding excess capacity have suggested an openness by the Commission to consider other calculation methodologies. Specifically, in the Aqua Docket No. W-218, Sub 497 Order, dated September 18, 2019, the Commission "requests that more evidence be presented by the parties regarding other formulas or methods for making excess capacity adjustments such that the Commission could determine by the weight of the evidence presented whether future growth projections or any other additional factors should be included in the approved methodology.

Witness Casselberry describes her excess capacity calculation as follows: Excess Capacity = (1 - Contributary Flow / Design Flow) x 100. She states that contributary flow is the amount of flow for the customers at the end of the update period and design flow is the design capacity of the utility infrastructure installed. Witness Casselberry notes that based on prior Commission orders in Docket Nos. W-354, Sub 128 and W-218, Sub 319, the contributary flow has been calculated as: Contributary Flow = SFE x 400 gpd where SFE is customer "Single Family Equivalent". She states that the Public Staff and Aqua both disagree with using the water system design standard of 400 gpd. She notes that the sewer system design standard is 360 gpd. Witness Casselberry used the sewer system design standard of 360 gpd in her calculation of excess capacity for this proceeding. She states that SFEs have been calculated the same way as in prior general rate cases using water meter sizes and American Water Works Association (AWWA) meter size factors, with the exception of Sparrows Bend Apartments. Witness Casselberry states that Sparrows Bend Apartments has a total of 228 apartments. There are ten 2-inch meters that when multiplied by the AWWA factor of 8, results in 80 SFEs. She testifies that the North Carolina Department of Environmental Quality, Division of Water Resources (DEQ) plan approval assigns a design flow of 64,080 gpd to Sparrows Bend Apartments, which when divided by 360 gpd equals 178 SFE. Witness Casselberry substituted 178 SFE for the 80 SFE determined using meter sizes. According to witness Casselberry, the total calculated SFE for the excess capacity calculation is 849.5. Witness Casselberry set forth her calculations of the SFEs in Casselberry Exhibit No. 8.

Witness Casselberry calculates that Contributory Flow = 849.5 SFE x 360 gpd = 305,820 gpd. She maintains that the WWTP installed, with the exception of the membrane set for 250,000 gpd of treatment capacity, is to treat 500,000 gpd of sewage flow. She states that the infiltration basins will take over 1,000,000 gpd of effluent from the WWTP. She used 500,000 gpd as the Design Flow for the WWTP and infiltration basins. Witness Casselberry testifies that the excess capacity is calculated as: Excess Capacity = (1 - 305,820 gpd / 500,000 gpd) x 100 = 38.80%. She recommends that the excess capacity adjustment of 38.80% be applied to the Company's WWTP and infiltration basins.

Witness Casselberry testifies that Pluris Hampstead included an additional 150 residential customers in its calculations of revenues and rate design in anticipation of significant near term growth on the system. Witness Casselberry states that the Company's adjustment would offset some of the excess capacity in the system. She contends that this is not the traditional rate making mechanism to account for excess capacity. She notes that she did not include anticipated customers in her calculation of revenues and rate design. She opines that using an excess capacity adjustment to match plant in service to SFE customers at the end of the update period is the appropriate mechanism. Public Staff witness Li applied the excess capacity percentage provided by witness Casselberry to plant in service, net of accumulated depreciation and contributions in aid of construction, as shown on Li Exhibit I, Schedule 2-1(a).

Pluris Hampstead disputes the Public Staff's excess capacity adjustment and disagrees with Public Staff witness Casselberry's testimony suggesting that there is excess capacity in Pluris Hampstead's existing wastewater plant, which is currently permitted for treatment of up to 250,000 gpd. However, for purposes of settlement the Public Staff and the Company agree to the amounts and rates shown in Stipulation Exhibits Nos. I and II, which include an excess capacity adjustment of 33.75%.

In her Verified Response, Public Staff witness Casselberry explains that as part of the give and take of negotiations in this case, the parties have stipulated and agreed to an excess capacity adjustment of 33.75%; consequently, a detailed calculation of the agreed-upon excess capacity percentage is not available. She did note that the Public Staff considered near-term customer growth during the settlement negotiations regarding this issue. The application of the excess capacity adjustment of 33.75% for purposes of this proceeding is shown on Stipulation Exhibit I, Schedule 2-1(a).

In the Stipulation, the Stipulating Parties acknowledge that Pluris Hampstead's compromise regarding the excess capacity issue, and the Public Staff's proposed adjustment relating thereto, is for purposes of settlement only and does not imply concurrence nor shall it be used as rationale for future argument or cited as precedent in any future proceeding.

Despite the disagreement between Pluris Hampstead and the Public Staff regarding the excess capacity on the WWTP, the Stipulating Parties reached agreement on a comprehensive settlement agreement. Therefore, based on the evidence of record, the Commission finds that the adjustments to rate base provided for in the Stipulation are appropriate for this proceeding. Accordingly, the appropriate level of rate base for use in this proceeding is as follows:

Item	Amount
Plant in service	$8,272,634
Accumulated depreciation	(840,214)
Net plant in service	7,432,419
Cash working capital	57,471
Contributions in aid of construction (CIAC)	(1,757,964)
Accumulated amortization	99,253
Prepaid tap on fees	(3,453,160)
Customer deposits	(20,750)
Accumulated deferred income taxes (ADIT)	(356,023)
Average tax accruals	(1,451)
Original cost rate base	$1,999,795

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-16

Operating Revenues

The evidence supporting these findings of fact is found in the Application and in the testimony of Pluris Hampstead witness Winters and Public Staff witnesses Casselberry and Li.

In its Application, Pluris Hampstead requested an increase in rates for providing sewer utility service in its service areas in Pender County, North Carolina designed to produce an overall increase in annual operating revenues of $419,214.

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:

WATER AND SEWER – RATE INCREASE

Item	Company Per Application	Difference	Amount per Public Staff
Service revenues	$470,463	$178,184	$648,647
Miscellaneous revenues	17,684	0	17,684
Uncollectible accounts	(2,143)	0	(2,143)
Total operating revenues	$486,004	$178,184	$664,188

Public Staff witness Casselberry determined the number of end-of-period (EOP) customers based on the billing data provided by the Company for the updated test year ending March 31, 2020. Witness Casselberry used EOP customers to calculate revenues at present and proposed rates, which she states represents the number of active customers billed in March 2020, the last month of the updated test year. She notes that EOP customers includes customer growth for the test period.

Witness Casselberry states that Pluris Hampstead started its billing analysis with the number of customers billed in September 2019, then added 150 residential flat rate customers, which is the number of tap fees collected, to reflect anticipated customer growth. Witness Casselberry disagreed with the Company's methodology to calculate customer growth. She states that it is not uncommon for developers to pay tap fees in advance to reserve capacity for construction at a later date. Witness Casselberry maintains that EOP customers reflect the actual customers being billed going forward, which includes customer growth throughout the test period.

Witness Casselberry describes some minor inconsistencies between the Public Staff's EOP customers and the Company's numbers in regard to commercial customers. She states that the Company used total customers billed to calculate the revenue and the Public Staff used EOP customers multiplied by 12 months. She further states that the Public Staff determined that the Company has one 4-inch commercial customer (Arbor Landing, 7 account # 30984) versus the Company's two, and two 6-inch commercial customers (Pender County Schools, account # 27728 and 27271) versus the Company's four.

Moreover, witness Casselberry testifies that the Public Staff's billing data includes active customers in nine pending franchise applications as shown in Casselberry Exhibit No. 1. She states that it is the Public Staff's position that these customers are being billed for service and that Pluris Hampstead has an obligation to continue serving them. She further states that if these customers were removed from the billing analysis in this proceeding, the revenue generated would be significantly understated. Witness Casselberry also calculates the total consumption for commercial customers for each meter size in her billing analysis. She provides the results of her billing analysis on Casselberry Exhibit Nos. 2 and 3.

Based on the Stipulation, and specifically Stipulation Exhibits I and II, the Company does not dispute the Public Staff adjustment to reflect the pro forma level of service revenues under present rates.

The Commission finds that the Public Staff's adjustments to operating revenues under present rates in this proceeding discussed above and stipulated by the parties are appropriate. Based upon the foregoing, the Commission concludes that the appropriate level of operating revenues under present rates for use in this proceeding is as follows:

Item	Amount
Service revenues	$648,647
Miscellaneous revenues	17,684
Uncollcetible accounts	(2,143)
Total operating revenues	$664,188

Further, based upon the agreed-upon level of operating revenues under present rates, the Commission concludes that Pluris Hampstead has requested an increase in rates in this proceeding that would produce $266,278 in additional total operating revenues, an increase of 40% over present annual total operating revenues.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17 - 19

Maintenance and General Expense

The evidence for these findings of fact is found in the verified Application and the accompanying NCUC Form W-1; the testimony of Pluris Hampstead witness Winters and Public Staff witnesses Casselberry and Li, and Stipulation Exhibits I and II.

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 Per Application	Difference	Amount Per Public Staff
Operation and Maintenance Expenses			
Salaries and wages	$146,828	0	$146,828
Employee benefits	(19,896)	0	(19,896)
Sludge removal expense	70,385	(6,397)	63,988
Purchased power	72,066	(13,143)	58,923
Chemicals	39,214	11,473	50,687
Materials and supplies	9,398	0	9,398
Contract services			
Engineering	1,550	0	1,550
Accounting	8,250	0	8,250
Legal	4,944	0	4,944
Management fees	33,242	0	33,242
Direct utility fees	10,832	(2,024)	8,808
Testing	14,642	3,668	18,310

Other	10,746	(1,608)	9,138
Rent expense	0	0	0
Insurance – general liability	5,798	0	5,798
Insurance – workers comp	1,015	0	1,015

Item	Company Per Application	Difference	Amount Per Public Staff
Insurance – other	17,960	0	17,960
Miscellaneous	22,451	0	22,451
Regulatory commission expense	13,500	4,877	18,377
Total O&M Expenses	$462,925	($3,154)	$459,771

Public Staff witness Casselberry states that Pluris Hampstead expensed $70,385 for removing sludge from the WWTP and lift stations. She notes that included in the $70,385, was $25,610 in response to emergency backups at various lift stations due to elevated pressure in the force main. Witness Casselberry states that in 2019, the Company installed a regional lift station at the midway point of the force main which has alleviated the elevated pressure issue in the force main thereby eliminating recurring emergency backups. Witness Casselberry recommends that the $25,610 in expense related to emergency backups should be amortized over a five-year period for an annual level of expense of $5,122. Witness Casselberry maintains that this level of annual expense will allow a reasonable amount of expense for emergency situations and will avoid overstating sludge removal expense on an ongoing basis. Witness Casselberry also adjusted sludge expense to reflect customer growth during the test year. She recommends $63,988 as a representative level of expense for sludge removal.

Witness Casselberry adjusted purchased power based on her review of the invoices provided by the Company. She increased purchased power to account for operational changes in 2019 at the WWTP and for three new lift stations added in 2019. She further increased purchased power for the lift stations to reflect customer growth. Witness Casselberry increased chemicals expense to reflect the 2019 increase in the cost of chemicals and to reflect customer growth during the test year. Witness Casselberry increased testing expense to reflect the current testing costs for the various tests and frequencies under Pluris Hampstead's DEQ Permit dated January 23, 2020.

Public Staff witness Li adjusted contractual services to remove duplicate trash removal fees in the amount of $2,024 and $1,608 of meter reading expense charged by PCU for the service period outside of the test year.

Witness Li states that she included a total of $91,833 of rate case expenses for this proceeding based on information provided by the Company regarding costs incurred to date and expected costs that will occur to complete this rate case proceeding. She states that the total rate case expenses of $91,883 is comprised of $18,108 in legal fees, $1,500 in contract labor, $67,275 in capitalized labor, and $5,000 in postage and printing to mail customer notices, the rate case filing fee, and miscellaneous expenses. Witness Li recommends that these expenses be amortized over a five-year period, resulting in annual rate case expense of $18,377.

On the basis of the Stipulation, the revisions made by the Public Staff in Li Exhibit I, and Stipulation Exhibits I and II, the Company and the Public Staff are in agreement concerning all adjustments recommended by Public Staff witnesses Casselberry and Li to maintenance and general expenses. Therefore, the Commission finds that the uncontested adjustments to maintenance and general expenses recommended by the Public Staff are appropriate adjustments to be made in this proceeding.

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
Operation and Maintenance Expenses:	
Salaries and wages	$146,828
Employee benefits	(19,896)
Sludge removal expense	63,988
Purchased power	58,923
Chemicals	50,687
Materials and supplies	9,398
Contract services	
Engineering	1,550
Accounting	8,250
Legal	4,944
Management fees	33,242
Direct utility fees	8,808
Testing	18,310
Other	9,138
Rent expense	0
Insurance – general liability	5,798
Insurance – workers comp	1,015
Insurance - other	17,960
Miscellaneous	22,451
Regulatory commission expense	18,377
Total O&M Expenses	$459,771

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-25

Depreciation, Amortization Expense, Taxes and Regulatory Fee

The evidence supporting these findings of fact is found in the verified Application and the accompanying NCUC Form W-1, the testimony of Public Staff witnesses Casselberry and Li, the testimony of Company witness Winters, and Stipulation Exhibits I and II. The following table summarizes the differences between the Company's level of depreciation and amortization expenses, taxes, and regulatory fee from its Application and the amounts recommended by the Public Staff:

Item	Company Per Application	Difference	Amount Per Public Staff
Depreciation expense	$279,622	(39,504)	240,118
Amortization of CIAC	(43,357)	15,150	(28,207)
Payroll taxes	7,257	0	7,257
Regulatory Fee	529	555	1,084
State Income Tax	0	2,583	2,583
Federal Income Tax	0	21,157	21,157
Total	244,051	(59)	243,992

With respect to Pluris Hampstead's depreciation expense, amortization expense, regulatory fee and income taxes, in light of the agreements reached in the Stipulation and revisions recommended by the Public Staff in its testimony and reflected in Stipulation Exhibits I and II, the Company does not dispute these adjustments recommended by the Public Staff. The Commission finds that the adjustments recommended by the Public Staff to depreciation expense, amortization expense, regulatory fee, and income taxes are appropriate adjustments to be made to operating revenue deductions in this proceeding.

Based upon the foregoing, the Commission concludes that the appropriate level of depreciation expense, amortization expense, payroll taxes, regulatory fee, and income taxes for use in this proceeding is as follows:

Item	Amount
Depreciation expense	$240,118
Amortization of CIAC	(28,207)
Payroll taxes	7,257
Regulatory Fee	1,084
State Income Tax	2,583
Federal Income Tax	21,157
Total	$243,992

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

The evidence for this finding of fact is contained in the testimony of Public Staff witness Casselberry, in the Stipulation, and in the Verified Response of witness Casselberry.

In her prefiled testimony, Public Staff witness Casselberry testifies that Pluris Hampstead has several new franchise applications pending before the Commission as shown in Casselberry Exhibit No. 1 and that her billing analysis includes the active customers in these pending applications. The Public Staff recommends that Pluris Hampstead obtain ownership and operational responsibility of the customer owned utility assets in these pending franchise applications. Further, witness Casselberry recommends that Pluris Hampstead file a monthly progress report with the Commission concerning the pending franchise applications identified in Casselberry Exhibit No. 1.

In her Verified Response, witness Casselberry explains that there are seven new franchise applications pending before the Commission which are incomplete, primarily because the Public Staff determined that Pluris Hampstead does not have ownership or operational responsibility over certain utility assets. She states that Pluris Hampstead is in the process of acquiring control of the utility assets and filing the appropriate documentation to complete these pending applications. Witness Casselberry notes that some of the pending applications require acquiring both the lift station and the mains while others require acquiring only the lift station or only the mains. She states that the Public Staff will verify that the Company has obtained ownership and operational responsibility of the assets to provide utility service and that the appropriate documents (i.e., agreement, contract, easement, or bill of sale) have been signed and filed as required to complete the application.

In the Stipulation, Pluris Hampstead agreed to file with the Commission monthly progress reports on the status of its efforts to acquire ownership and operational responsibility over the utility assets (i.e., lift station and/or mains) needed for the seven pending applications identified in Casselberry Exhibit No.1 to the direct testimony of Public Staff witness Casselberry. The Commission finds and concludes that this provision of the Stipulation is reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27 - 33

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

The evidence supporting these findings of fact is contained in the verified Application and the accompanying NCUC Form W-1, the testimony and exhibits of Company witness Gallarda, the testimony and exhibits of Public Staff witness Craig, and the Stipulation.

In its Application, the Company requested approval for its rates to be set using a rate of return on common equity of 9.70%, which would yield an overall rate of return on rate base for Pluris Hampstead of 6.69%. Witness Gallarda testified that these rates would yield a rate of return on rate base for the Company that would be less than what the Commission set in recent rate cases for Carolina Water Service (Docket No. W-354, Sub 360) and for Aqua North Carolina (Docket

No. W-218, Sub 497). Mr. Gallarda further testified that Pluris Hampstead advocated this approach in an effort to avoid increasing the amount of rate case expense that will be passed through to Pluris Hampstead's ratepayers by employing an expert witness to address this issue in this docket. Mr. Gallarda also testified that the Company's current capital structure is 56% debt and 44% equity.

Public Staff witness Craig, in his testimony, recommended an overall rate of return of 6.32%, based on the Company's capital structure as of March 31, 2020, that is composed of 57.66% long-term debt and 42.34% common equity. This recommended overall rate of return recommendation is based on a cost rate of long-term debt of 4.35%, and a cost rate for common equity of 9.00%.

As shown in the Stipulation, the Public Staff and the Company agreed that the Company's appropriate long-term debt cost is 4.35%, and that the Company's capital structure is 57.66% long-term debt and 42.34% common equity. The Stipulating Parties further agreed that based on a number of factors, including the impacts of the COVID-19 pandemic on customers and the changing economic conditions, the appropriate return on common equity to use in setting rates in this proceeding is 9.40%. The parties' compromise on this issue yields a return on equity that is lower than the 9.50% return on equity that the Commission found to be appropriate in a recent rate case involving Carolina Water Service (Docket No. W-354, Sub 364), where this issue was vigorously litigated.

The Commission has carefully reviewed the evidence related to the stipulated capital structure, the return on common equity and the overall rate of return and concludes that the stipulated and agreed-upon capital structure of 57.66% debt and 42.34% equity, the long-term debt cost rate of 4.35%, a return on common equity of 9.40%, and the opportunity to earn an overall rate of return of 6.49%, is just and reasonable. This will allow the Company, by sound management, the opportunity to produce a fair return for its shareholders, to maintain its facilities and services in accordance with the reasonable requirements of customers, and to compete in the market for capital on terms that are reasonable and fair to its customers and to its shareholders.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 34 - 37

The evidence for these findings of fact is found in testimony of Public Staff witnesses Casselberry, Li, and Craig and in Stipulation Exhibits I and II.

Accountant Li stated that she used the rate base method pursuant to N.C.G.S. § 62-133, to calculate the Public Staff's recommended revenue requirement in this proceeding. The Stipulating Parties agreed that Pluris Hampstead's rates should be adjusted by amounts which, after all pro forma adjustments, will produce revenues of $833,512. These rate increases will allow Pluris Hampstead the opportunity to earn a 6.49% overall rate of return, as stipulated. The stipulated rate increases represent an increase of $169,324 or 25.5% in total sewer operating revenues. Under the stipulated rates, the monthly flat sewer rate for a residential customer would increase from $63.95 to $82.50, or 29%.

Based upon the evidence of record, the Commission concludes that the stipulated rates and charges are just and reasonable and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the Agreement and Stipulation of Settlement is incorporated herein by reference and is hereby approved in its entirety;

2. That the Agreement and Stipulation of Settlement 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 Schedule of Rates, attached hereto as Appendix A, is hereby approved and deemed to be filed with the Commission pursuant to N.C.G.S. § 62-138, and the rates set forth therein are hereby authorized to become effective for service rendered on and after the date of this Order;

4. That the Notice to Customers, attached hereto as Appendix B, shall be mailed with sufficient postage or hand delivered to all affected customers in conjunction with the next regularly scheduled billing process;

5. That Pluris Hampstead shall file the attached Certificate of Service, properly signed and notarized, not later than 45 days after the issuance of this Order; and

6. That Pluris Hampstead shall file with the Commission monthly progress reports on the status of acquisition of lift stations needed for the seven pending applications identified in Casselberry Exhibit No.1 to the direct testimony of Public Staff witness Casselberry. The initial report shall be due the first day of the month beginning more than 15 days after the date of this Order and subsequent reports shall be filed monthly until all the lift stations are acquired.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of November, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

SCHEDULE OF RATES

for

PLURIS HAMPSTEAD, LLC

for providing sewer utility service

in

ALL OF ITS SERVICE AREAS IN NORTH CAROLINA

Pender County, North Carolina

Monthly Residential Flat Rate:	$ 82.50
Monthly Commercial Metered Rates:	
Base charge, zero usage:	
<1" meter	$ 23.50
1" meter	$ 58.75
1.7 " meter	$ 117.50
2" meter	$ 188.00
4" meter	$ 587.50
6" meter	$1,175.00
Usage charge, per 1,000 gallons	$ 16.50

Customers who ask to be reconnected at the same service location within nine months of disconnection, will be charged the entire flat rate or base monthly charge for the periods they were disconnected.

Reconnection Charge:

If sewer service cut off by utility for good cause: Actual cost

(Customers shall be given a written estimate of the actual costs prior to disconnection. An actual invoice of the costs shall be given to the customer following disconnection.)

APPENDIX A
PAGE 2 OF 2

Connection Fee-Residential: $3,200 per SFE

Each additional bedroom beyond three per residence $1,607

Connection Fee-Commercial: $3,200 per SFE

A single-family equivalent (SFE) for a detached single-family residence is three or less bedrooms.

A SFE for a commercial connection is determined by taking the design flow capacity for each non-residential commercial customer, as set forth in Administrative Code 15A NCAC 2 T .0114, and dividing the design flow by 360.

Road Bore Charge:

The road bore charge shall be the actual costs of labor and materials for the road boring. This charge shall be in addition to the connection fee. The customer may, choose to have a licensed contractor perform the road bore at the customer's sole expense, provided that the road bore and all related work shall be in accordance with Pluris Hampstead's standards.

The above connection fees, and Road Bore Charge do not apply to future connections for which prepaid connection fees have been received prior to the date of this Order.

Bills Due: On billing date

Bills Past Due: 15 days after billing date

Return Check Fee: $25.00

Billing Frequency:

Flat Rate Residential Customers Shall be monthly for service in advance

Metered Commercial Customers 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 the billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1305, Sub 12, on this the 13th day of November, 2020.

APPENDIX B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

NOTICE TO CUSTOMERS
DOCKET NO. W-1305, SUB 12
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Notice is hereby given that the North Carolina Utilities Commission has issued an Order authorizing Pluris Hampstead, LLC, to increase sewer rates in its service areas in Pender County, North Carolina. The new approved rates are as follows:

Monthly Residential Flat Rate:	\$ 82.50
Monthly Commercial Metered Rates:	
Base charge, zero usage:	
<1" meter	\$ 23.50
1" meter	\$ 58.75
1.5" meter	\$ 117.50
2" meter	\$ 188.00
4" meter	\$ 587.50
6" meter	\$1,175.00
Usage charge, per 1,000 gallons	\$ 16.50

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of November, 2020.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

WATER AND SEWER – RATE INCREASE

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 No. W-1305, Sub 12, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of __________________, 2020.

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 No. W-1305, Sub 12.

Witness my hand and notarial seal, this the ________ day of ________________, 2020.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ________________________________
Date

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Cliffside Mills Hydroelectric Generating Facility -- SP-147, SUB 0; Order Amending Certificate of Public Convenience and Necessity (01/08/2020)

Garisol Farm, LLC -- SP-9821, SUB 0; Order Allowing Withdrawal of Application and Closing Docket (03/24/2020)

Healing Springs Solar, LLC -- P-19877, SUB 0; Order Issuing Certificate (03/09/2020)

Sugar Solar, LLC -- SP-11728, SUB 0; Order Issuing Amended Certificate (05/28/2020)

ORDER CANCELING REGISTRATION AND CLOSING DOCKET

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Company	Docket No.	Date
Caswell Solar, LLC	SP-4280, SUB 0	(12/02/2020)
Daniel Solar, LLC	SP-5265, SUB 0	(12/02/2020)
ESA Goldsboro NC Phase 2, LLC	SP-7487, SUB 0	(12/23/2020)
Eastway Solar, LLC	SP-7737, SUB 0	(12/23/2020)
Saxapahaw Solar, LLC	SP-7736, SUB 0	(12/23/2020)
Stagecoach Solar Farm, LLC	SP-7734, SUB 0	(12/23/2020)
Turner Smith Solar, LLC	SP-5245, SUB 0	(12/02/2020)
Whiteville Solar, LLC	SP-5577, SUB 0	(12/02/2020)

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Company	Docket No.	Date
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Solar Pack NC1, LLC	SP-24720, SUB 0	(11/18/2020)
Solarpack NC2, LLC	SP-24721, SUB 0	(11/18/2020)

SP-8331 Sub 0 Order Issuing Certificate for Merchant Generating Facility 09/14/2020

SMALL POWER PRODUCERS – Filings Due Per Order

Apple, Inc. -- SP-1642,
SUB 0; SP-1642, SUB 6; SP-29052, SUB 0; Order Transferring Certificate of Public Convenience and Necessity (12/21/2020)
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SUB 4; SP-1642, SUB 5; SP-29052, SUB 1; Order Transferring Certificate of Public Convenience and Necessity (12/21/2020)

Avalon Hydropower, LLC -- SP-130, SUB 1; Order Amending Certificate of Public Convenience and Necessity and Registration (01/08/2020)

Chickenfoot Solar, LLC -- SP-4616, SUB 0; Order Renewing Certificate (04/16/2020)

City of Asheville -- SP-17215, SUB 1; Order Allowing Withdrawal of Application and Closing Docket (06/15/2020)

Fresh Air Energy II, LLC -- SP-2665,
SUB 42; Order Allowing Withdrawal of Application, Cancelling CPCN and Registration, and Closing Docket (04/23/2020)
SP-2665 Sub 55; SP-25812, SUB 0; Order Transferring Certificate of Public Convenience and Necessity and Registration (08/18/2020)

Fresh Air Energy XI, LLC -- SP-3557, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Registration, and Closing Docket (04/23/2020)

Hayes Solar, LLC -- SP-7011, SUB 0; Order Amending Certificate of Public Convenience and Necessity and Registration (05/27/2020)

Ingram Farm, LLC – SP-9015, SUB 0Order Allowing Withdrawal of Application, Cancelling CPCN and Registration, and Closing Docket (04/23/2020)

Madison Solar, LLC -- SP-6061, SUB 0; Order Cancelling Registration and Closing Docket (04/08/2020)

Monroe Solar, LLC -- SP-7009, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Registration, and Closing Docket (04/07/2020)

Orion Renewable Resources LLC -- SP-13695, SUB 0; SP-23286, SUB 0; Order Transferring Certificate of Public Convenience and Necessity and Registration (05/15/2020)

**ORDER ACCEPTING REGISTRATION OF
NEW RENEWABLE ENERGY FACILITY**

Orders Issued

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
Amigo Farm, LLC	SP-4293, SUB 0	(05/14/2020)
Badger Hill Solar, LLC	SP-8272, SUB 0	(06/12/2018)
Eisenhower Farm, LLC	SP-8223, SUB 0	(05/14/2020)
Highway 16 Farm, LLC	SP-7422, SUB 0	(05/14/2020)
Mastiff Solar, LLC	SP-8190, SUB 0	(05/14/2020)
Slider Solar, LLC	SP-7625, SUB 0	(09/21/2020)
Tubbs Farm, LLC	SP-4531, SUB 0	(05/14/2020)
Verona Solar, LLC	SP-8182, SUB 0	(05/14/2020)

NTE Carolinas Solar, LLC -- SP-8744 Sub 0; Order Allowing Withdrawal of Application, Canceling CPCN and Registration, and Closing Docket (12/09/2020)

ORDER CANCELLING REGISTRATION AND CLOSING DOCKET

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Company	Docket No.	Date
Blue Tick Solar, LLC	SP-9097, SUB 0	(08/27/2018)
California Energy Dairy #1, LLC	SP-3714, SUB 0	(08/27/2020)
California Energy Dairy #4, LLC	SP-3715, SUB 0	(08/27/2020)
California Energy Dairy #14, LLC	SP-5016, SUB 0	(10/06/2020)
Red Cedar Solar, LLC	SP-5240, SUB 0	(12/02/2020)
Charity Solar Farm, LLC	SP-7104, SUB 0	(12/15/2020)
Fresh Air Energy XXXV, LLC	SP-4898, SUB 0	(08/27/2020)
Ludie Brown Solar, LLC	SP-9358, SUB 1	(02/28/2020)
Airlie Solar Farm	SP-6696, SUB 0	(12/23/2020)

Aquenergy Systems, Inc. SP-451 Sub 2 Order Canceling Registration and Accepting Registration of New Renewable Energy Facility (11/06/2020)

Align RNG Magnolia, LLC -- SP-1103, SUB 0; SP-25630, SUB 0; Order Canceling Registration Closing Docket and Accepting Registration of New Renewable Energy Facility (11/06/2020)

RES Ag-DM 4-3, LLC; SP-1106, SUB 0; SP-25630, SUB 1; Order Canceling Registration Closing Docket and Accepting Registration of New Renewable Energy Facility (11/06/2020)

Washington Solar, LLC -- SP-6053, SUB 0; Order Renewing Certificate (11/02/2020)

SMALL POWER PRODUCERS – Filings Due Per Order *(Continued)*

ORDER ISSUING AMENDED CERTIFICATE
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Walkers Ridge Gastonia, LLC		
(Walkers Ridge Apartments)	WR-3159 Sub 0	(08/26/2020)
Waxhaw Mill Ventures, LLC		
(Mill on Main Apartments; The)	WR-3140, SUB 0	(06/30/2020)
West Tyvola Workforce, LLC		
(Avion Point Apts.)	WR-3010, SUB 0	(02/12/2020)
White Oak Grove Associates, LLC		
(White Oak Grove Apts.)	WR-3229, SUB 0	(10/15/2020)
Wilkesboro Acres, LLC		
(Wilkesboro Acres Mobile HP)	WR-3091, SUB 0	(05/20/2020)
Williams Road, LLC		
(Homestead Mobile Home Park)	WR-3044, SUB 0	(03/02/2020)

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Wilton-BB Matthews Owner, LLC		
(Bainbridge Matthews Apts.)	WR-3199, SUB 0	(10/26/2020)
Woodlands Landing, LLC		
(Woodlands Landing at Echo Farms Apartments)	WR-3088, SUB 0	(05/05/2020)
WRPV XIII Tribute Raleigh, LLC		
(Tribute Apartments; The)	WR-2715, SUB 0	(03/24/2020)
ZP NO. 331, LLC		
(198 Milltown Apartments)	WR-3112, SUB 0	(06/09/2020)
800 St. Mary's JV, LLC		
(800 St. Mary's Apartments)	WR-3256, SUB 0	(11/04/2020)
3117 Shannon Road Apartments, LLC		
(University Hill Apartments)	WR-3040, SUB 0	(03/13/2020)
2925 Commonwealth, LLC	WR-3182, SUB 0	(09/18/2020)

Cooper Beech Townhome Communities Thirty SPE, LLC -- WR-2918, SUB 0; Order Denying Application (01/29/2020)

EBSCO Enclave, LLC -- WR-2020, SUB 6; WR-2020, SUB 7; Order Granting Certificate of Authority, Approving Rates, and Closing Docket (12/04/2020)

Evolve Sneads Ferry Phase 3, LLC -- WR-3079, SUB 0; Order Granting Certificate of Authority, Granting Interim Authority to Pass Through Flat Rate for Sewer Service, and Requiring Customer Notice *(Evolve at Stones Bay Apts., Phase 3)* (05/05/2020)

Ginkgo Shattalon, LLC -- WR-3110, SUB 1; Order Granting HWCCWA and Full-Capture Certificates of Authority and Approving Rates (12/02/2020)

Haven Campus Communities-Charlotte, LLC -- WR-2701, SUB 0; Order Denying Application (01/29/2020)

RDA Holdings @ 10 Newbridge Parkway, LLC -- WR-2366, SUB 2; WR-2366, SUB 3; Order Granting Certificate of Authority, Approving Rates, and Closing Dockets (01/16/2020)

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WATER RESELLERS – Certificate *(Continued)*

Quail Valley On Camel c/o Hawthorne Residential Partners -- WR-2934, SUB 0; Order Granting Certificate of HWCCWA and Full-Capture Authority and Approving Rates *(Quail Valley on Carmel Apts.)* (01/23/2020)

Tribune Terrace, LLC -- WR-3168, SUB 0; Order Granting HWCCWA and Full-Capture Certificate of Authority and Approving Rates (11/24/2020)

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NC 2, LLC -- WR-1730, SUB 6; Order Dismissing Complaint and Closing Docket *(Mary Jane Lahman)* (07/13/2020)

Pine Mountain Property Association, Inc. -- W-1316, SUB 0; W-1316, SUB 1; W-1316, SUB 2; Order Dismissing Complaint and Closing Docket *(Fred and Vonis Waugh & Burke Mountain Southeast, LLC & Keith and Linda Shifflett)* (04/03/2020)

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Abbotts Run Wilmington, LLC	WR-3138, SUB 0 WR-2048, SUB 2	(06/30/2020)
ADE 101, LLC	WR-3219, SUB 0 WR-513, SUB 9	(12/30/2020)
Alexander Station Owner, LLC	WR-3260, SUB 0 WR-2220, SUB 4	(11/23/2020)
Alston Manor Investors JV, LLC	WR-3046, SUB 0 WR-2378, SUB 2	(03/11/2020)
AMFP IV Waterford, LLC	WR-2974, SUB 0 WR-2063, SUB 4	(01/07/2020)
Arrowhead Apartments, LLC	WR-3184, SUB 0 WR-2677, SUB 1	(08/28/2020)
B9 Brizo Owner, LLC	WR-3090, SUB 0 WR-2808, SUB 2	(05/26/2020)
Breit MF Ashford Place, LLC	WR-3246, SUB 0 WR-2153, SUB 3	(10/28/2020)
Brideport Fee Owner, LLC	WR-2991, SUB 0 WR-2151, SUB 4	(01/28/2020)
BCORE MF AS Lake Norman, LP	WR-3102, SUB 0 WR-2084, SUB 4	(08/14/2020)
BCORE MF Timber Creek, LP	WR-3022, SUB 0 WR-2675, SUB 1	(03/17/2020)

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	WR-2036, SUB 5	
Bel Circa Limited Partnership	WR-3169, SUB 0	(08/21/2020)
	WR-2015, SUB 2	
Bel Leigh L. P.	WR-3248, SUB 0	(10/29/2020)
	WR-2876, SUB 1	
Bel Weston Limited Partnership	WR-3185, SUB 0	(08/19/2020)
	WR-2159, SUB 5	
Bel Whetstone Limited Partnership	WR-3078, SUB 0	(04/22/2020)
	WR-1881, SUB 4	
Belhaven Estates MHC, LLC	WR-3034, SUB 0	(03/17/2020)
	WR-943, SUB 1	
Bell Fund V Wakefield, LLC	WR-3215, SUB 0	(10/01/2020)
	WR-1540, SUB 7	
BES Queens Fund XIII, LLC	WR-3155, SUB 0	(08/11/2020)
	WR-2626, SUB 1	
Bloomfield Estates, LLC	WR-3066, SUB 0	(05/13/2020
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BMF IV NC Park 2300, LLC	WR-3247, SUB 0	(10/29/2020)
	WR-2252, SUB 3	
BMF IV NC Victoria Park, LLC	WR-3251, SUB 0	(10/28/2020)
	WR-901, SUB 6	(10/28/2020)
Brannon Park Apts., LLC	WR-2995, SUB 0	(01/22/2020)
	WR-1676, SUB 5	
BREIT MF Modern Way, LP	WR-3167, SUB 0	(08/21/2020
	WR-2248, SUB 2	
Bridge WF NC Woodland Estates, LLC	WR-3149, SUB 0	(07/14/2020)
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Brightleaf Durham Associates, LLC	WR-3297, SUB 0	(12/15/2020)
	WR-2680, SUB 1	(12/15/2020)
Caswell Carter Holiday Park, LLC	WR-3057, SUB 0	(03/18/2020)
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CBC Partners, LLC	WR-3077, SUB 0	(04/22/2020)
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Charlotte Holdings 192, LLC	WR-3255, SUB 0	(12/01/2020)
	WR-1780, SUB 3	
Chase Rockford, LLC, et al.	WR-3076, SUB 0	(04/14/2020)
	WR-635, SUB 13	
Church Street MHP, LLC	WR-3109, SUB 0	(06/02/2020)
	WR-1996, SUB 4	
Cliffdale Operating Company, LLC	WR-3130, SUB 0	(06/18/2020)
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Clemmons Station Owner, LLC	WR-3261, SUB 0	(11/24/2020)
	WR-2427, SUB 5	
CLK Greensboro Owner, LLC, et al.	WR-3190, SUB 0	(09/14/2020)
	WR-1936, SUB 4	
Colony Burlington II, LLC	WR-3283, SUB 0	(11/18/2020)
	WR-1931, SUB 1	
Columns at Wakefield Property, LP	WR-3279, SUB 0	(11/18/2020)
	WR-1633, SUB 5	
CPUS Penrose, LP	WR-3093, SUB 0	(06/02/2020)
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Crabtree Lakeside, LLC	WR-3301, SUB 0	(12/03/2020)
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Croasdaile Cumberland Cove, LLC, et al.	WR-3132, SUB 0	(07/09/2020)
	WR-2542, SUB 2	
Crossroads Apartment Owner, LLC	WR-2985, SUB 0	(01/21/2020)
	WR-851, SUB 11	(01/21/2020)
Curtis T, LLC	WR-2980, SUB 0	(01/09/2020)
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CUSA N.C. Holdings, LP	WR-2425, SUB 5	(03/04/2020)
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DeRosa Capital II, LLC	WR-3292, SUB 1	(12/07/2020)
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DPR Deer Harbor, LLC	WR-2989, SUB 0	(01/22/2020)
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DPR Patterson Place, LLC	WR-3249, SUB 0	(11/24/2020)
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<u>WATER RESELLERS – Sale/Transfer</u> *(Continued)*

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WATER RESELLERS – Sale/Transfer *(Continued)*

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Sterling StoneBrook, LLC	WR-3005, SUB 0 WR-2202, SUB 2	(01/22/2020)
STO Properties, LLC, et al.	WR-3067, SUB 0 WR-2454, SUB 4	(04/29/2020)
	WR-3067, SUB 1 WR-2454, SUB 5	(04/29/2020)
Stone Ridge Charlotte, LLC	WR-3150, SUB 0 WR-2304, SUB 4	(08/11/2020)
Strata Eastchester, LLC	WR-3165, SUB 0 WR-1762, SUB 6	(07/31/2020)
Strata HollowNC, LLC	WR-3163, SUB 0 WR-1670, SUB 5	(07/31/2020)
Strata Midtown, LLC	WR-3164, SUB 0 WR-2231, SUB 3	(07/31/2020)
Strata Brandemere, LLC	WR-3162, SUB 0 WR-2921, SUB 1	(07/31/2020)
SW1 Cleveland Crossing, LLC	WR-3310, SUB 0 WR-1592, SUB 1	(12/30/2020)
TBR Lake Boone Owner, LLC	WR-3187, SUB 0; WR-1374, SUB 7 WR-1374, SUB 8	(11/06/2020)
Thornhill Apartments Owner, LLC	WR-3259, SUB 0 WR-1867, SUB 4	(11/13/2020)
Triangle Arborgate, Inc.	WR-3286, SUB 0 WR-1125, SUB 80	(11/20/2020)
Triangle Avalon of Asheville, Inc.	WR-3289, SUB 0 WR-1125, SUB 82	(11/24/2020)
Triangle Huntersville Commons, LLC	WR-3285, SUB 0 WR-1125, SUB 79	(11/18/2020)
Triangle Woodbridge, Inc.	WR-3287, SUB 0 WR-1125, SUB 81	(12/22/2020)
Trinity Station Owner, LLC	WR-3268, SUB 0 WR-2219, SUB 3	(11/20/2020)

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Turkoise Durham, LLC	WR-3035, SUB 0	(06/26/2020)
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	WR-1876, SUB 4	
USCMF Marshall Park, LLC	WR-2972, SUB 0	(01/07/2020)
	WR-1864, SUB 2	
Village at Brierfield Owner, LLC	WR-3271, SUB 0	(11/17/2020)
	WR-2223, SUB 5	
Village at Roadstone Station IV, LLC, et al.	WR-3217, SUB 0	(12/17/2020)
	WR-1601, SUB 4	
Waterford Place Owner, LLC	WR-3018, SUB 0	(02/25/2020)
	WR-2197, SUB 1	
Waters Edge Owner, LLC	WR-3272, SUB 0	(11/20/2020)
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WE Brassfield Park Owner, LLC	WR-3131, SUB 0	(06/24/2020)
	WR-1619, SUB 7	
West Shore Pleasant Ridge, LLC	WR-3125, SUB 0	(06/18/2020)
	WR-1767, SUB 2	
Westford Apartments WEH, LP	WR-3311, SUB 0	(12/30/2020)
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Weston Lakeside, LLC	WR-3054, SUB 0	03/18/2020
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Wexford Owner, LLC	WR-3273, SUB 0	(11/17/2020)
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Whispering Pines Mobile Estates, LLC	WR-3288, SUB 0	(12/07/2020)
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	WR-3288, SUB 1	(12/07/2020)
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Whitehall Estates Apartments, LLC, et al.	WR-3134, SUB 0	(06/23/2020)
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Wildewood W99 LAP, LLC	WR-3227, SUB 0	(10/09/2020)
	WR-2961, SUB 2	
Willow Glen Rockford, LLC	WR-3081, SUB 0	(04/22/2020)
	WR-633, SUB 13	
Willows NC Apartments SPE, LLC	WR-3001, SUB 0	(01/22/2020)
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Windsor Park NOAH, LLC	WR-3188, SUB 0	(09/24/2020)
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Woodbrook Owner, LLC	WR-3275, SUB 0	(11/24/2020)
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86 North CGC, LLC	WR-2885, SUB 0	(01/07/2020)
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118PC Apt, LLCs	WR-3157, SUB 0	07/22/2020
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1000HL Apts, LLC	WR-3298, SUB 0	(12/02/2020)
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2630 South MMXIX, LLC	WR-3069, SUB 0	(04/07/2020)
	WR-2628, SUB 1	
6225 HC Holdings, LLC	WR-3210, SUB 0	(11/13/2020)
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12000 Wisdom Drive Holdings, LLC	WR-3052, SUB 0	(03/18/2020)
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DeRosa Capital II, LLC	WR-3292, SUB 0	(12/07/2020)
	WR-2596, SUB 4	
Georgetowne Woods Holdings #1	WR-3030, SUB 0	(03/04/2020)
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Livingston at Laurel Hills, LLC	WR-3056, SUB 0	(03/19/2020)
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MIMG CLXVIII Forest Hills Sub, LLC, et al.	WR-3293, SUB 0	(12/22/2020)
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Raleigh Holdings 176, LLC	WR-3254, SUB 0	(11/17/2020)
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Autumn Park Owner, LLC	WR-1378, SUB 8	(09/02/2020)
Avant at Steele Creek, LP	WR-2897, SUB 1	(07/30/2020)
Awoods, LLC	WR-2568, SUB 2	(09/09/2020)
B9 Brizo Owner, LLC	WR-3090, SUB 1	(08/07/2020)
Bainbridge NC, LLC	WR-2504, SUB 3	(09/09/2020)
Banner Parkside, LLC	WR-2450, SUB 3	(08/03/2020)
BCORE MF Anson, LLC	WR-2850, SUB 1	(08/07/2020)
BCORE MF AS Lake Norman, LP	WR-3102, SUB 1	(12/29/2020)
Beaucatcher Flats Apartments, LLC, et al.	WR-2643, SUB 2	(08/28/2020)
Beaver Creek Apex, LLC	WR-881, SUB 7	(10/19/2020)
Beaver Creek Crossing, LLC	WR-2472, SUB 3	(09/15/2020)
Bedrock Holdings II (Charlotte), LLC		
(Harris Pond Apts.)	WR-1718, SUB 30	(07/23/2020)
(Mallard Creek Apartments)	WR-1718, SUB 31	(07/23/2020)
(Northlake Apartments)	WR-1718, SUB 32	(07/24/2020)
(Providence Court Apartments)	WR-1718, SUB 33	(07/23/2020)
Bel Encore Limited Partnership	WR-2571, SUB 1	(08/31/2020)
Bel Garrett Limited Partnership		
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(Garrett West Apartments)	WR-2933, SUB 2	(08/06/2020)
Bel Haven, LLC, d/b/a Bel Haven LLC, MA	WR-2389, SUB 3	(08/11/2020)
Bell Fund V 605 West, LP	WR-2145, SUB 4	(08/20/2020)
Bell HNW Exchange Apex, LLC	WR-1765, SUB 4	(08/31/2020)
Bel Pineville Limited Partnership	WR-1037, SUB 10	(08/25/2020)
Bel Republic Limited Partnership	WR-2666, SUB 2	(08/19/2020)
Bel Thornberry Limited Partnership	WR-2177, SUB 4	(07/28/2020)
Bel Tryon Limited Partnership	WR-2828, SUB 1	(09/14/2020)
Bel Whetstone Limited Partnership	WR-3078, SUB 1	(09/15/2020)
Bel Whitehall Limited Partnership	WR-2140, SUB 4	(08/11/2020)
Bel Vinoy, LLC	WR-2307, SUB 4	(08/10/2020)
Belhaven Estates MHC, LLC	WR-3034, SUB 1	(12/07/2020)
Bell Fund V Hawfield Farms, LP	WR-1904, SUB 5	(09/23/2020)
Bell Preston Reserve, LLC	WR-2668, SUB 2	(09/29/2020)
Berkeley Place Apartment Owner, LLC	WR-2474, SUB 3	(09/01/2020)

WATER AND SEWER – Tariff Revision for Pass-Through *(Continued)*

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BES Berewick Fund XII, LLC	WR-2502, SUB 3	(08/03/2020)
BFN Steele Creek, LLC	WR-2074, SUB 5	(09/22/2020)
BHC – Hawthorne Pinnacle Ridge, LLC	WR-1513, SUB 7	(08/25/2020)
BHI-SEI Hamilton Ridge, LLC	WR-2477, SUB 1	(08/10/2020)
BHI-SEI Mariners, LLC	WR-1228, SUB 5	(08/10/2020)
BH3 – Indigo, LLC	WR-2687, SUB 1	(11/24/2020)
BH3 – Linden Davidson, LLC	WR-2684, SUB 2	(08/07/2020)
BIF – Amberwood at Lochmere, LLC	WR-3051, SUB 1	(09/15/2020)
Big Arbor Village NC, LLC	WR-1660, SUB 7	(07/28/2020)
BIG Ellis NC, LLC	WR-2877, SUB 1	(08/27/2020)
Blue Atlantic Flats, LP	WR-2908, SUB 1	(08/06/2020)
Boulevard at North Cedar Street, LLC; The	WR-2079, SUB 5	(08/05/2020)
BR Park & Kingston Charlotte, LLC	WR-1795, SUB 7	(08/07/2020)
BR Wesley Village, LLC	WR-2340, SUB 3	(09/24/2020)
Bradford I SPE, LLC	WR-1579, SUB 3	(08/13/2020)
Braxton Place Apartments, LLC	WR-2142 SUB 1	(01/03/2020)
BRC Alexandria Park, LLC	WR-2006, SUB 5	(11/10/2020)
BRC Charlotte 485, LLC	WR-501, SUB 13	(07/28/2020)
BRC Jacksonville Commons, LLC	WR-1275, SUB 5	(07/27/2020)
Bridge WF NC Woodland Estates, LLC	WR-3149, SUB 1	(09/15/2020)
Brier Creek Investors JV, LLC	WR-2189 SUB 1	(11/04/2020)
Brightwood Crossing Apartments, LLC	WR-543, SUB 10	(10/07/2020)
Broadstone Morehead, LLC	WR-3139, SUB 1	(11/12/2020)
Broadstone Willard, LLC	WR-2865, SUB 1	(06/01/2020)
Bromley Park, LLC	WR-665, SUB 2	(12/14/2020)
Brookson Flats Associates SPE, LLC	WR-2469 Sub 2	(08/05/2020)
Bryanskybrook, LLC, et al.	WR-2762, SUB 2	(07/28/2020)
C and J Catalyst, LLC	WR-1116, SUB 6	(09/17/2020)
Cambridge NC Warwick, LLC	WR-514, SUB 9	(06/01/2020)
Camden Glen, LLC	WR-1913, SUB 3	(05/12/2020)
Canopy at Baybrook, LLC, et al.	WR-2759, SUB 2	(08/04/2020)
Carlyle Place, LLC	WR-647, SUB 2	(12/14/2020)
Carmel Valley II, LP	WR-71, SUB 13	(08/14/2020)
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Carver Equity Fund, LLC	WR-2787, SUB 1	(01/08/2020)
Cary Greens, LP	WR-2380, SUB 3	(08/14/2020)

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CC NRP, LLC	WR-2754, SUB 2	(08/04/2020)
CC Tryon Park at Rivergate, LLC, et al.	WR-2453, SUB 3	(08/07/2020)
CCB Montford Park, LLC	WR-2767, SUB 2	(09/29/2020)
CCC Asbury Flats, LLC	WR-2033, SUB 5	(11/12/2020)
CCC Flats on Front, LLC	WR-3122, SUB 1	(10/13/2020)
CCC Forest at Biltmore Park	WR-1742, SUB 7	(09/28/2020)
CCC Midwood Flats, LLC	WR-2527, SUB 2	(09/08/2020)
CCC One Norman Square, LLC	WR-1628, SUB 6	(08/07/2020)
CCC Residences at Biltmore Park, LLC, et al.	WR-2229, SUB 4	(09/29/2020)
CCC Verde Vista, LLC	WR-2115, SUB 4	(09/28/2020)
CCC The Edison, LLC	WR-1709, SUB 4	(08/03/2020)
CCC Villages at Pecan Grove, LLC, et al.	WR-1970, SUB 3	(08/28/2020)
CC-SFA MF Atherton, LLC	WR-2878, SUB 1	(09/03/2020)
Central Avenue Apartments Charlotte, LLC	WR-2900, SUB 1	(10/26/2020)
Charlotte Hills MHP, LLC	WR-2314, SUB 4	(10/26/2020)
Charlotte NC Apartments SPE, LLC	WR-2832, SUB 1	(09/17/2020)
Charlotte Northlake Multifamily LeaseCo, LLC	WR-2332, SUB 2	(12/29/2020)
Charlotte Owner 2, LLC, et al.		
(Matthews Point Apartments)	WR-2376, SUB 9	(10/01/2020)
(Waterford Hills Apts.)	WR-2376, SUB 10	(10/01/2020)
(Mission Matthews Place Apts.)	WR-2376, SUB 11	(10/01/2020)
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(Lenox at Patterson Place Apts.)	WR-2868, SUB 1	(08/12/2020)
Chelsea Investments, LLC	WR-2232, SUB 4	(09/23/2020)
Clemmons Town Center Apartments, LLC	WR-1756, SUB 2	(12/14/2020)
CMF Crescent Commons, LLC	WR-2949, SUB 1	(09/08/2020)
CMF 15 Portfolio, LLC		
(Colonial Grand at Patterson Place Apts.)	WR-955, SUB 57	(07/20/2020)
(Arringdon Apartments)	WR-955, SUB 58	(07/20/2020)
(Colonial Grand at Beverly Crest Apts.)	WR-955, SUB 59	(07/22/2020)
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DPR Ellis Crossing Property, LLC	WR-2581, SUB 2	(08/10/2020)
DPR Liberty Warehouse, LLC	WR-3008, SUB 1	(09/14/2020)
DRI/Maple Tompkins Mill, LLC	WR-2789, SUB 2	(08/27/2020)
Durham 345 Owner, LLC	WR-2575 SUB 3	(08/12/2020)
Durham City Center II, LLC	WR-2543, SUB 1	(12/01/2020)
Durham Holdings #1, LLC	WR-1467, SUB 7	(11/12/2020)
Durham Holdings #3, LLC	WR-2517, SUB 1	(09/15/2020)
Eagle Property LLC	WR-1085, SUB 2	(10/28/2020)
EBEX WS, LP	WR-2596, SUB 3	(09/25/2020)
Edison Two, LLC, et al.	WR-2432, SUB 3	(10/05/2020)
Edward Rose Millennial Development, LLC		
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(Avellan Springs Apartments)	WR-1935, SUB 6	(10/22/2020)
EEA-Wildwood, LLC	WR-629, SUB 12	(09/21/2020)
Elevation Apartments, LLC	WR-1663 SUB 1	(01/02/2020)
Elizabeth Square Holdco, LP	WR-2698, SUB 2	(08/12/2020)
Elon Crossing, LLC	WR-1535, SUB 7	(08/14/2020)
Everest Brampton, LP	WR-1091, SUB 10	(09/01/2020)
Exchange Holly Springs Holdings, LLC	WR-2963, SUB 1	(09/30/2020)
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FC Meadowbrook LLC	WR-280, SUB 7	(12/23/2020)
Fieldstone Partners, LLC WR-1749, SUB 1 Order Approving Tariff Revision		(02/17/2020)
Fisher-Forest Village Salisbury Square Investment, LLC	WR-2266, SUB 5	(12/29/2020)
Forest at Chasewood Apartments, LLC	WR-1997, SUB 5	(08/24/2020)
Forest Edge Townhomes, LLC	WR-3053, SUB 1	(12/23/2020)
Fountains Matthews, LLC	WR-2023, SUB 4	(09/22/2020)
FPII Crossing at Quail, LLC	WR-2634, SUB 2	(08/24/2020)
Free Throw NC Partners, LLC	WR-1855, SUB 4	(06/10/2020)
Friendly Center Apartments, LLC	WR-2887, SUB 1	(05/26/2020)
Friendly Greene, LLC	WR-2720, SUB 1	(06/15/2020)
G&I IX Lake Cameron, LLC	WR-2572, SUB 2	(08/31/2020)
G Partnership, LP	WR-1262, SUB 9	(08/27/2020)
Galleria Partners II, LLC	WR-925, SUB 8	(09/01/2020)
Galleria Property, LLC	WR-2605, SUB 2	(09/30/2020)
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Ginkgo Arbor Creek, LLC	WR-2483, SUB 5	(09/23/2020)
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Ginkgo Briar Creek, LLC	WR-2443, SUB 3	(08/24/2020)
Ginkgo BVG, LLC	WR-1519, SUB 8	(08/24/2020)
Ginkgo Croasdaile, LLC	WR-2282, SUB 5	(08/18/2020)
Ginkgo Kimmerly, LLC	WR-1729, SUB 6	(08/24/2020)
Ginkgo Lakeside, LLC	WR-2815, SUB 1	(08/24/2020)
Ginkgo Parkwood, LLC	WR-2275, SUB 5	(08/24/2020)
Ginkgo Quail Hollow, LLC	WR-3103, SUB 1	(08/24/2020)
Ginkgo Weyland, LLC	WR-2613, SUB 1	(09/01/2020)
Ginkgo Willowdaile, LLC	WR-2530, SUB 3	(08/24/2020)
Ginkgo Yorktown, LLC	WR-2959, SUB 1	(08/19/2020)
Glenwood Raleigh Apartments LLC	WR-1833, SUB 4	(01/08/2020)
Golden Triangle #1 LLC	WR-1400, SUB 7	(09/09/2020)
Golden Triangle #4 – 5th Street, LLC	WR-1809, SUB 6	(10/06/2020)
Golden Triangle #7 – Commonwealth, LLC	WR-2097, SUB 5	(09/01/2020)
Goldsboro Apartments Investors, LLC	WR-1131, SUB 2	(09/14/2020)
Goldsboro Properties, LLC	WR-1263, SUB 2	(01/21/2020)
Gramercy Glenwood, LLC	WR-2123, SUB 3	(09/11/2020)
Grand Reserve at Pavilions, LP	WR-2320, SUB 2	(07/30/2020)
Grand View Holdings, LLC	WR-2042, SUB 3	(10/22/2020)
Graybul Meadows, LP	WR-2030, SUB 12	(09/28/2020)
GRE Asheville Owner, LLC	WR-2849, SUB 1	(09/18/2020)
GRE Carrington, LLC	WR-2604, SUB 2	(08/06/2020)
Guardian Tryon Village, LLC	WR-1335, SUB 8	(08/14/2020)
GUGV Poplar Charlotte Property Owning, LP	WR-2267, SUB 4	(09/28/2020)
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(Hampstead Place Apartments)	WR-208, SUB 5	(10/06/2020)
Harding Place Residential Partners, LLC	WR-2569, SUB 2	(09/16/2020)
Harris Blvd. Communities I, LLC	WR-478, SUB 5	(08/25/2020)
HART Providence Farm, LP	WR-2994 SUB 1	(08/04/2020)
Hawthorne at Smith Creek Apartments, LLC	WR-2879, SUB 1	(10/14/2020)
Hawthorne-Midway Cadence, LLC	WR-1485, SUB 6	(10/13/2020)
Hawthorne-Midway Stratford, LLC, et al.	WR-1553, SUB 7	(08/25/2020)
Hawthorne-Midway Turtle Creek Phase III, LLC, et al.	WR-2077, SUB 6	(08/25/2020)

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Matthews Cove, LLC	WR-2284, SUB 3	(09/09/2020)
MC Holiday City Property, LLC	WR-2800, SUB 1	(10/07/2020)
MC NC Acquisition 3, LLC	WR-2981, SUB 1	(09/01/2020)
MC Ridge NC, LLC	WR-2857, SUB 1	(07/23/2020)
Mercury/GR-WW-CB, LLC	WR-2774, SUB 1	(04/20/2020)
Meridian at Broad Street Market, LLC	WR-2409, SUB 4	(09/17/2020)
Meridian at Harrison Pointe, LLC	WR-1568 SUB 6	(09/23/2020)
Meridian at Nichols Plaza, LLC	WR-2835, SUB 1	(09/17/2020)
Meridian at Ten Ten, LLC	WR-2790, SUB 1	(09/17/2020)
Meridian/H.C., LLC	WR-1500, SUB 6	(11/02/2020)
Metro 808 Charlotte, LLC	WR-1714, SUB 6	(08/31/2020)
MFREVF III – Enclave at Rivergate, LP	WR-2579, SUB 2	(08/12/2020)
MHNC Thornwood Village of Sanford, LLC	WR-2931, SUB 1	(11/24/2020)
Mid-America Apartments, Limited Partnership		
(Colonial Village at Beaver Creek Apts.)	WR-22, SUB 152	(07/20/2020)
(Colonial Village at Deerfield Apts.)	WR-22, SUB 153	(07/20/2020)
(Colonial Grand at Research Park Apts.)	WR-22, SUB 154	(07/20/2020)
(Hermitage at Beechtree Apts.)	WR-22, SUB 155	(07/20/2020)
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(Colonial Grand at Ayrsley Apts.)	WR-22, SUB 157	(07/21/2020)
(Colonial Grand at Cornelius Apts.)	WR-22, SUB 158	(07/21/2020)
(Colonial Grand at Huntersville Apts.)	WR-22, SUB 159	(07/21/2020)
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(Colonial Grand at Univ. Center Apts.)	WR-22, SUB 162	(07/21/2020)
(Colonial Reserve at South End Apts.)	WR-22, SUB 163	(07/21/2020)
(Colonial Village at Chancellor Park Apts.)	WR-22, SUB 164	(07/21/2020)
(Colonial Village at Matthews Apts.)	WR-22, SUB 165	(07/21/2020)
(Colonial Village at South Tryon Apts.)	WR-22, SUB 166	(07/21/2020)
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(Post Gateway Place Apts.)	WR-22, SUB 169	(07/21/2020)
(Post Park at Phillips Place Apts.)	WR-22, SUB 170	(07/21/2020)
(Post Uptown Place Apartments)	WR-22, SUB 171	(07/21/2020)
(Timber Crest at Greenway Apts.)	WR-22, SUB 172	(07/20/2020)

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NXRTBH Radbourne Lake, LLC	WR-1722, SUB 6	(07/27/2020)
One Hilltop, LLC	WR-1077, SUB 8	(09/08/2020)
OREI Plantation at Fayetteville Property Owner, LLC	WR-2786, SUB 2	(09/16/2020)
Oxford Gateway Apartments, LLC	WR-2764, SUB 2	(10/08/2020)
PAC Citypark View, LLC	WR-2161 SUB 4	(09/15/2020)
Palisades Residences, LLC	WR-2961, SUB 1	(09/02/2020)
Palladium Park Apartments, LLC	WR-2821, SUB 2	(11/10/2020)
Park & Abbey	WR-2324, SUB 3	(10/14/2020)
Parkside REC, LLC	WR-2040, SUB 5	(10/06/2020)
Park West Village Phase III, LLC	WR-2226, SUB 4	(09/28/2020)
Passco Asheville Exchange DST	WR-2898, SUB 1	(09/22/2020)
Patterson Multifamily Durham, LP	WR-2178 SUB 3	(12/29/2020)
PBOne Dilworth, LP	WR-2936, SUB 1	(07/29/2020)
PBOne Main Street, LP	WR-2943, SUB 1	(07/29/2020)
PBOne Ninth Street, LP	WR-2938, SUB 1	(07/29/2020)
PC Links, LLC	WR-1149, SUB 9	(08/03/2020)
Pecan Grove MHP, LLC	WR-2257, SUB 3	(01/21/2020)
PEP Pavilion Village, LLC	WR-3099, SUB 1	(09/11/2020)
Perimeter Lofts JML, LLC	WR-2688, SUB 2	(07/30/2020)
Perimeter Station Midtown, LLC, et al.	WR-2689, SUB 2	(07/28/2020)
Phillips Mallard Creek, LLC	WR-1310, SUB 4	(11/09/2020)
Pier Properties, LLC	WR-1138, SUB 6	(10/05/2020)
Pine Glen Limited Partnership	WR-1399, SUB 3	(07/31/2020)
Pineville Apartments, LLC		
(Ascent Pineville Apts.)	WR-2082, SUB 2	(02/25/2020)
(Ascent Pineville Apts.)	WR-2082, SUB 3	(12/14/2020)
Piper Glen Apartments Associates, LLC	WR-252, SUB 8	(08/07/2020)
Plantation Park Apartments, Inc.	WR-644, SUB 12	(08/31/2020)
Poplar Manor, LLC	WR-2292, SUB 4	(09/01/2020)
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Preserve Forest, LLC	WR-2108, SUB 4	(09/09/2020)
Presley Oaks, LP	WR-2902, SUB 1	(07/30/2020)
Presley Uptown Venture, LLC	WR-3058, SUB 1	(10/07/2020)
PRG Windsor Square Associates, LLC	WR-1226, SUB 6	(08/05/2020)
PR II/Wood Croft, LLC	WR-2997, SUB 1	(09/08/2020)

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SOF-X Mission University Pines, LP	WR-2073, SUB 5	(07/29/2020)
Solis Patterson Place Develop. Owner, LLC	WR-2848, SUB 1	(09/22/2020)
South End Apartments Holdco, LP	WR-2699, SUB 2	(08/12/2020)
South Front Block, LLC	WR-2233, SUB 1	(01/03/2020)
South Front, LLC	WR-1134, SUB 3	(01/02/2020)
South LaSalle Apartments, LLC	WR-1629, SUB 6	(08/17/2020)
South Square Owner, LLC	WR-1387, SUB 8	(09/02/2020)
South Terrace Apartments North Carolina, LLC	WR-689, SUB 10	(09/14/2020)
Southpoint Glen Property, LP	WR-3002, SUB 1	(09/08/2020)
Southwood Realty Company		
(Quail Woods Apts.)	WR-910, SUB 36	(09/21/2020)
(Carriage House Apts.)	WR-910, SUB 38	(09/21/2020)
(The Landings Apts.)	WR-910, SUB 39	(09/18/2020)
(Azalea Apartments)	WR-910, SUB 42	(09/21/2020)
Southwood River Crossing, LLC	WR-2782, SUB 1	(09/03/2020)
Southwood Windsor Upon Stonecrest, LLC	WR-2847, SUB 1	(09/03/2020)
Spectrum South End, LLC	WR-1011, SUB 9	(08/07/2020)
Spyglass-GPG Junction, LLC, et al.	WR-2737, SUB 2	(07/22/2020)
SRC Charleston Place, LLC	WR-2241, SUB 3	(09/15/2020)
Stafford Place, LLC	WR-1573 SUB 2	(12/14/2020)
Stallings Mill Apartments, LLC	WR-2299, SUB 2	(09/11/2020)
Station Nine Owner, LLC	WR-2567, SUB 2	(08/25/2020)
Steele Creek Apts. Property Owner, LLC	WR-1332, SUB 5	(08/20/2020)
Steele Creek Property, LLC	WR-3055, SUB 1	(08/07/2020)
Sterling Charlotte Apartments II, LLC	WR-2714, SUB 1	(09/23/2020)
Sterling Forest, LLC	WR-2230, SUB 4	(10/07/2020)
Stonewall Station Property Owner, LLC	WR-2912, SUB 1	(09/02/2020)
Strata Eastchester, LLC	WR-3165, SUB 1	(11/23/2020)
Strata HollowNC, LLC	WR-3163, SUB 1	(12/01/2020)
Strata Icon, LLC	WR-2925, SUB 1	(06/24/2020)
Strawberry Hill Associates, LP	WR-293, SUB 15	(07/27/2020)
Strouse, Greenberg Properties VI L.P.	WR-983, SUB 7	(08/03/2020)
Suburban Apartment Managers, LLC	WR-2814, SUB 1	(08/27/2020)
Summit Street, LLC	WR-1741, SUB 5	(11/10/2020)
Sutton Place Trails, LP	WR-3004, SUB 1	(09/08/2020)
Swannanoa Bend, LLC	WR-2760, SUB 1	(04/28/2020)
Sycamore at Tyvola, LLC	WR-2484, SUB 3	(08/05/2020)
Town & Country MHP, LLC	WR-2255, SUB 4	(09/17/2020)

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TREA Centric Gateway, LLC	WR-2983, SUB 1	(08/12/2020)
TREA SH Chancery Village, LLC	WR-2953, SUB 1	(10/27/2020)
TREA SH Promenade, LLC	WR-2951, SUB 1	(10/27/2020)
TREA SH Silos South End, LLC	WR-2952, SUB 1	(10/27/2020)
Triangle Cloisters of Mt. Holly, Inc.	WR-1532, SUB 2	(09/22/2020)
Triangle Mills Creek, Inc.	WR-1580, SUB 3	(09/21/2020)
Triangle Real Estate Brentwood, LLC	WR-2253, SUB 2	(09/17/2020)
Triangle Real Estate of Gastonia, Inc.		
(Arborgate Apts.)	WR-1125, SUB 71	(09/02/2020)
(Lake Mist Apts.)	WR-1125, SUB 72	(09/02/2020)
(Woodbridge Apts.)	WR-1125, SUB 73	(09/02/2020)
(Bluff Ridge Apts.)	WR-1125, SUB 74	(09/15/2020)
(Legacy of Abbington Place Apts.)	WR-1125, SUB 75	(09/16/2020)
(Huntersville Commons Apts.)	WR-1125, SUB 76	(09/16/2020)
(Hudson Woods Apts.)	WR-1125, SUB 77	(09/21/2020)
Triangle Riverfront, Inc.	WR-1452, SUB 2	(09/22/2020)
Trinity Properties, LLC		
(Campus Walk Apts.)	WR-1696, SUB 23	(07/24/2020)
(Georgetown Apartments)	WR-1696, SUB 25	(07/24/2020)
Trotter Company	WR-593, SUB 7	(09/01/2020)
TS Creekstone, LLC	WR-1461, SUB 8	(09/14/2020)
TS New Bern, LLC		
(Fountains Southend Apts.)	WR-1541, SUB 5	(01/03/2020)
(Fountains Southend Apts.)	WR-1541, SUB 6	(10/19/2020)
TS Westmont, LLC	WR-1462, SUB 8	(09/21/2020)
TSG Matthews, LLC	WR-2217, SUB 4	(08/24/2020)
UEP Apartments, LLC	WR-2975, SUB 1	(08/14/2020)
US MF 1100 South, LP	WR-2860, SUB 1	(09/01/2020)
University City Community, LLC		
(Blu at Northline Apartments)	WR-2462, SUB 2	(05/12/2020)
(Blu at Northline Apartments)	WR-2462, SUB 3	(08/03/2020)
(Blu at Northline Apartments)	WR-2462, SUB 4	(11/16/2020)
Village 1373 Greensboro, LLC	WR-2802, SUB 1	(06/23/2020)
Vinings at Morehead, LLC	WR-1216, SUB 6	(09/08/2020)
VTT Carver Pond, LLC	WR-1509, SUB 6	(11/23/2020)
Vyne on Central Partners, LLC	WR-2204, SUB 5	(10/06/2020)
Wafra Invest Loft 135, LP	WR-2305, SUB 4	(08/03/2020)
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Waterford Creek, LLC	WR-2086, SUB 2	(07/29/2020)
Waterford Square Apts. Associates, LLC	WR-251, SUB 12	(08/07/2020)
Waxhaw Mill Ventures, LLC	WR-3140, SUB 1	(11/03/2020)
Waypoint Barrington Owner, LLC, et al.	WR-2333, SUB 4	(08/11/2020)
WDF-4 Wood NoDa Owner, LLC	WR-2587, SUB 2	(11/16/2020)
WE McAlpine Creek Owner, LLC	WR-1790, SUB 6	(07/20/2020)
WE Mission Triangle Point, LLC	WR-2436, SUB 2	(08/31/2020)
WE RTP Owner, LLC, et al.	WR-2265, SUB 2	(08/31/2020)
WE York Ridge Owner, LLC	WR-2845, SUB 1	(07/22/2020)
Weaverville Apartments, LLC	WR-2374, SUB 3	(09/02/2020)
Wendover Partners, LLC	WR-2870, SUB 1	(11/02/2020)
West 1st Street Apartments Investors, LLC	WR-2347, SUB 3	(08/24/2020)
Westford Apartments WEH, LP	WR-2809, SUB 1	(08/19/2020)
Westridge Place, LLC	WR-637, SUB 8	(08/18/2020)
Westridge Village, LLC	WR-1142, SUB 6	(08/14/2020)
West Shore Aurea, LLC	WR-2465, SUB 2	(10/26/2020)
Weston Lakeside, LLC	WR-3054, SUB 1	(11/02/2020)
WF-ARK NCMF Apartments, LLC	WR-2296, SUB 3	(08/27/2020)
WF Independence Boulevard, LLC	WR-2839, SUB 1	(02/17/2020)
Whitehall Estates Apartments, LLC, et al.	WR-3134, SUB 1	(08/04/2020)
Whitehall Village Apartments, LLC	WR-2659, SUB 2	(08/04/2020)
Wilmington Gallery II, LLC	WR-2779, SUB 1	(04/20/2020)
Willows NC Apartments SPE, LLC	WR-3001, SUB 1	(09/18/2020)
Willow Woods DNB, LLC	WR-2817, SUB 1	(12/29/2020)
Windsor Landing Investments I, LLC	WR-886, SUB 7	(02/11/2020)
Windsor Park NOAH, LLC	WR-3188, SUB 1	(12/01/2020)
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WMCi Charlotte III, LLC	WR-258, SUB 17	(08/05/2020)
WMCi Charlotte IV, LLC	WR-269, SUB 17	(08/06/2020)
WMCi Charlotte V, LLC	WR-340, SUB 16	(08/06/2020)
WMCi Charlotte VII, LLC	WR-392, SUB 15	(08/06/2020)
WMCi Charlotte VIII, LLC	WR-466, SUB 15	(08/06/2020)
WMCi Charlotte IX, LLC	WR-467, SUB 15	(08/06/2020)
WMCi Charlotte X, LLC	WR-638, SUB 13	(08/06/2020)
WMCi Charlotte XI, LLC	WR-1117, SUB 10	(08/05/2020)
WMCi Charlotte XII, LLC	WR-1136, SUB 9	(08/06/2020)
WMCi Charlotte XV, LLC	WR-1486, SUB 7	(08/11/2020)

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WMCi Raleigh II, LLC	WR-317, SUB 15	(08/06/2020)
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WMCi Raleigh VII, LLC	WR-1372, SUB 8	(08/05/2020)
WMCi Raleigh VIII, LLC	WR-1693, SUB 6	(08/05/2020)
WMCi Raleigh IX, LLC	WR-1754, SUB 6	(10/14/2020)
Woodland Estates MHP, LLC	WR-1863, SUB 5	(10/26/2020)
Woods Edge Pearl Place, LLC, et al.	WR-2819, SUB 1	(09/23/2020)
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WRPV XIII Audubon Cary, LP	WR-2696, SUB 1	(11/09/2020)
WRPV XIII AG Charlotte, LP	WR-2694, SUB 1	(11/09/2020)
WRPV XIII Highland Charlotte, LP	WR-2955, SUB 1	(11/09/2020)
WRPV XIII Retreat Charlotte, LP	WR-2695, SUB 1	(11/09/2020)
Yards at Noda, LLC	WR-1640, SUB 6	(08/10/2020)
54 Station Apartments, LLC	WR-2766, SUB 1	(08/12/2020)
100 Spring Meadow Drive Apartments Investors, LLC	WR-47, SUB 16	(08/28/2020)
200 East, LP	WR-2909, SUB 1	(10/19/2020)
150W CGC LLC	WR-2661, SUB 1	(01/02/2020)
401 South Mint Street Apartments Investors, LLC	WR-1634, SUB 6	(09/11/2020)
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650 Stonewall LLC	WR-2709, SUB 1	(12/21/2020)
708 Rhyne Road, LLC	WR-2858, SUB 1	(09/14/2020)
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905 7TH, LLC	WR-2060, SUB 3	(01/13/2020)
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2332 Dunlavin Way, LLC	WR-1781, SUB 4	(01/14/2020)
2630 South MMXIX, LLC	WR-3069, SUB 1	(09/16/2020)
3117 Shannon Road Apartments, LLC	WR-3040, SUB 1	(11/12/2020)
3217 Shamrock, LLC	WR-2147, SUB 3	(01/14/2020)
3500 Spanish Quarter, LLC	WR-2116, SUB 2	(01/15/2020)
4700 Twisted, LLC	WR-1885, SUB 4	(01/14/2020)
5115 Park Place Owner, LLC	WR-2228, SUB 4	(10/05/2020)
5920 Monroe, LLC	WR-1780, SUB 2	(01/07/2020)
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