ONE-HUNDRED SEVENTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

Volume I

ISSUED FROM
JANUARY 1, 2017 THROUGH DECEMBER 31, 2017

ONE-HUNDRED SEVENTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2017, through December 31, 2017

Edward S. Finley, Jr., Chairman

Bryan E. Beatty, Commissioner

ToNola D. Brown-Bland, Commissioner

* Don M. Bailey, Commissioner

Jerry C. Dockham, Commissioner

James G. Patterson, Commissioner

Lyons Gray, Commissioner

* Daniel G. Clodfelter, Commissioner

North Carolina Utilities Commission
Office of the Chief Clerk
M. Lynn Jarvis
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

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.

* Daniel G. Clodfelter, appointed July 1, 2017, replacing Don M. Bailey

LETTER OF TRANSMITTAL

December 31, 2017

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, 2017, we hereby present for your consideration the report of the Commission's significant decisions for the 12-month period beginning January 1, 2017, and ending December 31, 2017.

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

Edward S. Finley, Jr., Chairman

Bryan E. Beatty, Commissioner

ToNola D. Brown-Bland, Commissioner

Jerry C. Dockham, Commissioner

James G. Patterson, Commissioner

Lyons Gray, Commissioner

Daniel G. Clodfelter, Commissioner

M. Lynn Jarvis, Chief Clerk

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Public Utility Status of American Homes 4 Rent – Public Staff Request for a Declaratory Ruling	)))	ORDER APPROVING STIPULATED AGREEMENT

BY THE COMMISSION: On March 15, 2016, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a petition requesting that the Commission issue a declaratory ruling as to the public utility status of American Homes 4 Rent (AH4R) and Conservice, LLC (Conservice). In the Petition, the Public Staff alleged that AH4R and Conservice were acting as unauthorized *de facto* public utilities under G.S. 62-3(23)a.2 by re-billing tenants for water and sewer service based upon metered usage.

On March 18, 2016, the Commission issued an Order Requesting Comments. In said Order, the Commission found good cause existed to require: "(1) AH4R, Conservice and any other interested party to file comments on the Public Staff's Petition for a Declaratory Ruling as to the public utility status of AH4R and/or Conservice by April 18, 2016; (2) the Public Staff to file reply comments by April 28, 2016; (3) any party wishing to intervene in this docket to file a petition to intervene by April 18, 2016; and (4) the Clerk to serve a copy of this Order by certified mail return receipt requested on AH4R and Conservice."

On April 15, 2016, the Attorney General filed Notice of Intervention in the docket pursuant to G.S. 62-20. Also, on that date, the Attorney General filed a Motion to extend the time for any party to file comments. By Order dated April 18, 2016, the Commission extended the time to file comments until Monday, April 25, 2016.

On April 25, 2016, Invitation Homes, LP (Invitation Homes or IH) and the Attorney General each filed comments. Also on that date, AH4R and Conservice filed joint comments. On April 28, 2016, the Public Staff filed reply comments.

By Order issued October 18, 2016, the Commission granted the Public Staff's request that the Commission issue a declaratory ruling that AH4R and Conservice are public utilities within the meaning of the Public Utilities Act when they impose a separate charge for water and/or sewer utility service based upon a tenant's metered usage.

On May 25, 2017, Conservice, AH4R and the Public Staff (collectively referred to as the Stipulating Parties) submitted an Agreement and Stipulation of Settlement (Stipulation, Stipulated Agreement and/or Motion) for the Commission's consideration and approval. In the Stipulation, the Stipulating Parties explained that they had engaged in further discussion with regard to pertinent issues in this docket, *i.e.*, the re-billing of water and sewer services based upon a tenant's metered usage, and reached an agreement with regard to those issues. In addition, the Stipulating Parties explained that they had engaged in further discussion and had reached agreement on settlement terms with respect to two issues that were not addressed in this docket, *i.e.*, the unauthorized re-billing of tenants for electric and gas services based upon metered usage. Finally, the Stipulating Parties explained that because the issues presented in this docket are part of broader concerns raised by the Public Staff but not filed in any formal complaint docket, they believed that the present docket would be appropriate for filing a settlement resolving all related issues. The Stipulating Parties stated that they had agreed to the following:

1. **ACCOUNTING.** As to the North Carolina single family homes owned by AH4R at which utilities were re-billed to tenants by AH4R/Conservice with associated fees (Covered Properties), AH4R and Conservice jointly provided detailed data to the Public Staff reflecting a full accounting of the Covered Properties from inception of billing for electricity, gas, water and sewer in North Carolina through the present as to all administrative fees (including set up fees), late fees, and notice fees collected by AH4R/Conservice plus 10% interest calculated on the total amount of such collected fees (collectively, Refundable Fees). The accounting provided by AH4R/Conservice has been subject to Public Staff review, and the Public Staff has calculated refund amounts with interest through January 31, 2017, for all affected accounts. AH4R/Conservice agrees with the Public Staff's calculations, and agrees that interest at a 10% annual rate will be added up to the date of refund since refunds will be made after January 31, 2017.

2. **REFUND PROCEDURE.**

   A. AH4R/Conservice shall attempt to notify current and former tenants at the Covered Properties, who paid any Refundable Fees. Notice shall be made by all of the following means (with the exception of Subsection (i.) below, which is only applicable to current tenants), to be undertaken within 90 days of the Commission's approval of this Agreement and Stipulation on Settlement (the "Approval"):

      i. For all current tenants of Covered Properties, credit(s) will be issued by AH4R and/or Conservice to the tenant's account, reflecting the total amount of the Refundable Fees. A list of the details of the fees refunded will be provided to the current tenants, if specifically requested by tenant. All tenants will be notified no later than the date of their refunds that they may request an itemization of the fees being refunded. For current tenants receiving a refund in this manner, Subsections (ii.) through (vi.) shall not apply.
      ii. Letter to current or forwarding address of tenant.
      iii. Letter to address of tenant's guarantor (if address available).
      iv. E-mail to tenant (if address available).
      v. E-mail to tenant's guarantor (if address available).
      vi. For former tenants who do not respond to the letter or email notice within 15 business days, Conservice/AH4R will make a call to the last known telephone number(s) of the former tenant and his/her guarantors, notifying them of whom to contact and the deadline to make contact for purposes of receiving their refund.

B. For former tenants, the notices shall contain a fee refund settlement document, and shall state that the tenant must sign and return the document within 60 days or else not be eligible for a refund. For each former tenant successfully contacted by the process set forth in Subsection 2.A above, and who submitted a completed fee refund settlement document, AH4R/Conservice will refund to the former tenant his or her share of the Refundable Fees, which is to include 10% interest. A list of the details of the fees refunded will be sent to the former tenants either by mailing or emailing, if specifically requested by tenant. Former tenants will be notified no later than the date of their refunds that they may request an itemization of the fees being refunded.

C. A former tenant's eligibility for a refund of any Refundable Fees ceases 60 days after the last notice is sent as provided for in Section 2.A above. In recognition of any unclaimed refunds, Conservice and AH4R agree as follows:

Conservice shall reduce the billing fee for all AH4R tenants in North Carolina for whom Conservice is or will be handling billing to $2.50 per applicable utility, for twenty-four (24) months from the date AH4R's application to resell utility service is approved. If a new tenant begins a lease with AH4R during the applicable 24-month reduced fee period, then that tenant will also receive the reduced fee during the remainder of the 24-month period. Additionally, after the refund process identified above is completed, Conservice and AH4R shall donate 25% of the unclaimed refunds to a nonprofit 501(c)(3) charity selected by the Public Staff.

D. Every 30 days after initiating the refund process, until the refund process is complete, AH4R/Conservice shall provide the Public Staff with a written report of refunds actually made, by account and refund amount and date.

3. AGREEMENT ON RESOLUTION OF MOTION IN M-100, SUB 144, AND OTHER MATTERS; NO FURTHER CLAIMS.

A. Conservice and AH4R confirm that neither party, together or separately, is involved in any billing of rental property tenants in North Carolina for water, sewer, natural gas, or electric service, as of January 1, 2017, forward, except as expressly authorized by North Carolina law and the North Carolina Utilities Commission pursuant to the Public Utility Act; provided, however, that for the accounts included in the refund calculation, the Stipulating Parties agree that Conservice and AH4R may "pass through" utility bills to tenants without any mark-up or additional fees during a transition period that will end with the closing of the North Carolina General Assembly's 2017 session(s) or December 31, 2017, whichever comes last.

B. The Stipulating Parties agree that the purpose of this Stipulation is to globally resolve and settle any and all claims relating to the matters addressed herein, with respect to utility billing activities occurring before January 1, 2017, specifically: (i) the rebilling of usage-specific utility charges (including any of the following: electric, gas, water, sewer) and/or associated fees at AH4R properties, and (ii) any and all issues raised by the Commission or the Public Staff in Docket No. M-100, Sub 144, and (iii) other formal or informal investigations, complaints, claims, and/or demands made by tenants, the Commission or the Public Staff relating to these issues and docket. The Stipulating Parties request that if the Commission accepts and approves this Stipulation, that its Order approving the Stipulation state that all matters and issues raised in Docket M-100, Sub 144, have been fully resolved and that no further investigations, complaints, claims, and/or demands shall be brought against any of the Stipulating Parties based on these issues, with respect to utility billing activities occurring before January 1, 2017.

4. **AGREEMENT TO SUPPORT FURTHER LEGISLATIVE EFFORTS.** The Stipulating Parties agree that they will continue to cooperate and support further legislation that would allow owners and lessors of single-family homes to pass through usage-specific charges for water, sewer, electricity and gas under Commission regulation, including a $3.75 monthly administrative fee for any water and/or sewer resale and a separate $3.75 fee for any electric and/or natural gas resale. They further agree to collaborate on the implementation of such legislation.

5. **RESERVATION OF RIGHTS.** For purposes of compromise and entering into this Stipulation and without waiving any rights of appeal set forth herein, the Stipulating Parties agree to the provisions set forth above. The stipulation terms set forth in Sections 1-4 immediately above are contrary to the AH4R/Conservice legal position in this matter and docket, and AH4R and Conservice expressly reserve the right, if the Stipulation is not accepted by the Commission in its entirety consistent with Section 7 *infra,* to appeal any and all aspects of the Commission's decision in this docket.

6. **AGREEMENT IN SUPPORT OF SETTLEMENT; NON-WAIVER.**

A. The Stipulating Parties shall act in good faith and use their best efforts to recommend to the Commission that this Stipulation be accepted and approved. The Stipulating Parties further agree that this Stipulation is in the public interest and that they will support the reasonableness of this Stipulation before the Commission, and in any appeal from the Commission's adoption and/or enforcement of this Stipulation or portion thereof.

B. The provisions of this Stipulation do not reflect any position asserted by any of the Stipulating Parties, but reflect instead the compromise and settlement among the Stipulating Parties as to all of the issues covered hereby. No Stipulating Party waives any right to assert or oppose any position in any future proceeding or docket before the Commission and in any court, or in any appeal of a Commission Order in this docket that varies from any part of this Stipulation.

C. This Stipulation is a product of negotiation among all the Stipulating Parties and no provision of this Stipulation shall be strictly construed in favor of or against any Stipulating Party.

7. **STIPULATION BINDING ONLY IF ACCEPTED IN ITS ENTIRETY.** This Stipulation is the product of negotiation and compromise of a complex set of issues, and no portion of this Stipulation is or will be binding on any of the Stipulating Parties unless the entire Agreement and Stipulation is accepted by the Commission. If the Commission rejects any part of this Stipulation or imposes any change or condition on approval of this Stipulation or if the Commission's approval of this Stipulation is rejected or conditioned by a reviewing court, the Stipulating Parties agree to meet and discuss the applicable Commission or court order and to attempt in good faith to determine if they are willing to modify the Stipulation consistent with the order. No Party shall withdraw from the Stipulation prior to complying with the foregoing sentence. If any Party withdraws from the Stipulation, any Party retains the right to seek additional procedures before the Commission or the courts on appeal, including offering testimony, cross-examination of witnesses and supplementation of the record with additional direct or rebuttal testimony, with respect to issues addressed by the Stipulation and no Party shall be bound or prejudiced by the terms and conditions of the Stipulation, including each party's right to appeal any issue, term, or condition if this Stipulation is not accepted by the Commission in its entirety. In the event the Commission enters the Approval or makes any other disposition of this case that varies from or alters the terms of this Stipulation, including in response to any position taken by other Intervenors herein, the Stipulating Parties shall have all rights of appeal available under law and shall not be deemed to have waived any right of appeal of any issue, finding or conclusion in the Approval Order by virtue of entering into this Stipulation.

8. **MISCELLANEOUS.** This Stipulation may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. Execution by facsimile signature shall be deemed to be, and shall have the same effect as, execution by original signature. The parties shall each bear their own costs, attorney's fees and other fees incurred in connection with Docket M-100, Sub 144; and this Agreement.

On June 2, 2017, the Commission issued an Order Requesting Comments from Invitation Homes, Inc. and the Attorney General, i.e., two parties of record in this docket who had not participated in the discussions between the Stipulating Parties, and who had not formally consented to the Stipulation proffered by the Stipulating Parties to the Commission for approval. The Order Requesting Comments permitted IH and/or the Attorney General to file comments regarding the proposed Stipulation with the Commission by June 15, 2017. The Stipulating Parties were permitted to file a reply to any such comments on or before June 22, 2017.

As of the date of this Order, neither IH nor the Attorney General filed comments in this docket. Therefore, it is appropriate for the Commission to act upon the request made by the Stipulating Parties that the Stipulation and/or Motion be approved.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After carefully considering the Stipulated Agreement and the record proper, the Commission finds and so concludes that good cause exists to grant the Motion to approve the Stipulation in its entirety and without modification. Therefore, the Commission hereby grants the Motion to approve the Stipulation in its entirety and without modification. Further, the Commission finds and so concludes that all matters and issues raised in Docket M-100, Sub 144, have been fully resolved by the Stipulated Agreement and that no further investigations, complaints, claims, and/or demands shall be brought before the Commission against any of the Stipulating Parties based on these issues, with respect to utility billing activities occurring before January 1, 2017.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of July, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. M-100, SUB 145

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Rulemaking Proceeding to Consider Proposed Rule Establishing Procedures for Settlements and Stipulated Agreements	)))	ORDER DECLINING TO ADOPT PROPOSED SETTLEMENT RULES

BY THE COMMISSION: On July 14, 2016, North Carolina Waste Awareness and Reduction Network, Inc. (NC WARN) filed a Petition for Rulemaking in the above-captioned docket. In summary, NC WARN alleged that in recent significant Commission dockets it experienced unfair impediments to participating fully in negotiated settlements by the Public Staff and other parties. In support of its allegations, NC WARN attached a summary of pertinent proceedings in four Commission dockets. NC WARN asserted that settlements are often reached between the Public Staff and the utility or between the utility and another party without other parties having the opportunity to enter into the negotiations. Further, NC WARN stated that settlements are sometimes reached before the deadline for other parties to intervene, file testimony, or conduct discovery, and at other times the settlements are presented just days prior to the expert witness hearing, without adequate time for expert review.

In addition, NC WARN contended that settlements often are presented to the Commission as a fait accompli, in that the settlement includes a non-severability clause providing that no portion of the settlement will be binding on the settling parties unless the settlement is approved by the Commission in its entirety.

Moreover, NC WARN stated that all settlements should be filed openly with full transparency. NC WARN asserted that there is a lack of transparency of the terms of settlements, especially when side agreements, such as between the utility and another party, are not filed with the Commission, or are filed under seal as confidential trade secrets. NC WARN stated that a case in point was the merger between Duke Energy Corporation and Progress Energy, Inc., in Docket Nos. E 7, Sub 986 and E-2, Sub 998. According to NC WARN, numerous "secret agreements" were made so that major parties would agree to the merger.

NC WARN stated that it was unable to find model rules for settlements or rules by other Commissions incorporating settlement procedures into their hearing procedures. It further noted that many judicial bodies across the country have requirements that parties to litigation enter into mediated settlement discussions, but that these guidelines do not include time limits or address the question of multiple parties entering into a settlement under specific requirements.

In addition, NC WARN attached an essay authored by Scott Hempling entitled "Regulatory Settlements: When Do Private Agreements Serve the Public Interest?" (Hempling article). NC WARN stated that Hempling's conclusions are summarized in two principles:

(1) A settlement proposal must be backed by principles and evidence aligned with commission priorities.

(2) The resources, expertise, and alternatives available to each party must be roughly equivalent. Under these conditions, no one party's view of "the public interest" prevails for reasons other than merit.

Finally, NC WARN attached a proposed rule that it suggested as a starting point for the Commission and parties to use in developing a rule to establish a settlement process that NC WARN would view as fair and transparent. NC WARN stated that it would be glad to work with other parties and interest groups to develop this rule and to provide additional comments in support of the proposed rule. The primary components of the rule proposed by NC WARN are: (1) the Commission should encourage the parties to settle matters between and among themselves in order to reduce the issues to be heard by the Commission; (2) settlements filed with the Commission shall be supported by credible evidence, expert testimony, and exhibits; (3) the Commission will not accept a settlement until 10 days after the deadline for intervention or the filing of expert testimony established by the Commission; (4) the settlement shall be accompanied by a statement that all of the parties had the opportunity to participate in the settlement negotiations, and to review and comment on the settlement at least 10 days before it was filed with the Commission; (5) all parties should be encouraged to file statements as to which provisions of the settlement they support, oppose, or have no position on; (6) the parties entering into the settlement shall file expert testimony and exhibits providing support for the settlement; (7) the Commission will not accept settlements that require acceptance of the settlement in its entirety or not at all; (8) parties should be encouraged to submit data requests or pursue other discovery as soon as possible so that the information available to all parties is roughly equivalent prior to the review of the settlement. Late-filed discovery requests will not provide grounds to extend the settlement review period; and (9) all parties should carefully examine all filings in order to minimize, if not eliminate, filings under seal as confidential.

On August 1, 2016, the Commission issued an Order Requesting Comments on Proposed Rule. The Order requested that the Public Staff and other interested parties file comments and reply comments on the rule proposed by NC WARN. In addition, the Order included the investor-owned electric and natural gas public utilities as parties to this docket without the need for those entities to file petitions to intervene.

Petitions to intervene were filed by Carolina Utility Customers Association, Inc. (CUCA) and the North Carolina Sustainable Energy Association (NCSEA). The Commission issued Orders allowing the intervention of NCSEA and CUCA on August 1, 2016 and August 25, 2016, respectively.

On September 16, 2016, initial comments were filed by the Public Staff; jointly by Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), Virginia Electric and Power Company d/b/a Dominion North Carolina Power (DNCP), Piedmont Natural Gas Company, Inc. (Piedmont), Public Service Company of North Carolina, Inc. (PSNC), and Frontier Natural Gas Company, LLC (Frontier) (collectively, utilities); NCSEA and NC WARN.

On October 14, 2016, reply comments were filed by the Public Staff, CUCA and NC WARN.

Summary of Comments

Public Staff

The Public Staff opposes the rule proposed by NC WARN. The Public Staff states that the rule is unnecessary and would hinder good faith negotiations between parties in Commission proceedings, citing the history of parties working together to resolve issues through settlement, and G.S. 62-69(a) requiring the Commission to encourage the parties to settle dockets through stipulations, settlement agreements and consent orders. In addition, the Public Staff cites State ex rel. Util. Comm'n v. Carolina Util. Customers Ass'n, 348 N.C. 452, 466, 500 S.E.2d 693, 703 (1998), and Knight Publ'g Co. v. Chase Manhattan Bank, 131 N.C. App. 257, 262, 506 S.E.2d 728, 731 (1998) as examples of court decisions touting the benefits of settlements in utilities regulation and business litigation, respectively.

Further, the Public Staff submits that settlements promote the informal exchange of ideas and information among the parties, the elimination of insignificant or noncontroversial issues ahead of an evidentiary hearing, informed decision-making and the efficient administration of justice, especially in the complex matters that are typically before the Commission. Moreover, settlements result in savings to consumers by reducing litigation expenses that would otherwise be recoverable by utilities as a component of the cost of providing utility service.

The Public Staff discusses the Hempling article and states that the apparent thrust of the essay is a concern that settlements can "edge the commission out of its statutory role" and "induce regulatory passivity." Further, Hempling expresses concern about "resource differentials" between parties representing private interests and those representing the public interest. The Public Staff opines that such concerns about resource differentials between utilities and consumers in Commission proceedings were addressed by the General Assembly many years ago with the enactment of G.S. 62-15 and the designation of about 87 former Commission staff positions as the Public Staff. In addition, the Public Staff notes that it is entirely independent of the Commission in the performance of its duties, being under the sole supervision, direction, and control of an Executive Director appointed by the Governor, and is prohibited by G.S. 62-70 from engaging in ex parte communications with the Commission, as are all parties to a pending docket.

Citing State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998) (CUCA I), and State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000) (CUCA II), the Public Staff addresses NC WARN's contention that recent settlements contested by NC WARN were a *fait accompli* and were simply rubber stamped by the Commission. The Public Staff states that in compliance with the above Supreme Court cases, the Commission cannot simply accept a nonunanimous settlement, but instead must weigh all of the evidence and render an independent decision supported by the evidence.

With regard to NC WARN's objection to non-severability clauses in settlements, the Public Staff states that a settlement is a package that represents the give-and-take negotiations of the parties. In the negotiating process a settling party makes trade-offs to obtain the relief that it wants, agreeing in return to the relief that the other party wants. The non-severability clause protects a party from the possibility that the Commission might reject the settlement relief that it bargained to receive and accept the relief that it bargained to give. If that occurs, then the non-severability clause gives the party the right to withdraw from the settlement agreement.

The Public Staff discusses other flaws in the proposed rule, including:

- The proposed rule omits any parameters for maintaining confidentiality in settlement discussions involving proprietary and trade secret information that is filed with the Commission under seal. It is impractical to allow a party to participate in settlement discussions without having signed a confidentiality agreement, as that party lacks the full information necessary to meaningfully participate. Additionally, the parties should be required to affirm compliance with North Carolina Rule of Evidence 408, which prohibits the admission of evidence related to settlement discussions.

- The prohibition on filing settlements before intervention/testimony deadlines would nullify the goal of promoting judicial economy, and appears to be an attempt to require the stipulating parties to provide other parties with a basis for opposing a settlement without conducting discovery.

- The timelines in the proposed rule are unrealistic. Constructive settlement discussions are a complex process. They become possible as the parties develop their respective cases through discovery and analysis and determine that a good faith opportunity exists to explore resolving some or all of the issues. For example, it is difficult to negotiate rate design in a general rate case if a revenue requirement has not yet been established. Thus, the timeline required for determining whether or not settlement discussions are warranted varies from case to case, and once begun, actual negotiations can range from days to months.

- The proposed rule does not adequately define "opportunity to participate" in settlement negotiations. As noted above, settlement discussions are typically very fluid and involve the exchange of ideas and information between groups and individuals through various means, sometimes simultaneously. Including every party on every communication is simply not possible. In addition, some parties come into settlement negotiations unprepared to participate, having conducted little or no discovery. Any rule governing the settlement process should contain a provision requiring good faith participation in the process and include a mechanism for excluding parties seeking to delay or obstruct negotiations.

- The proposed rule threatens the constitutional rights of parties to form contracts without government restrictions, citing Muncie v. Ins. Co., 253 N.C. 74, 79, 116 S.E.2d 474, 478 (1960), and Alford v. Textile Ins. Co., 248 N.C. 224, 227, 103 S.E.2d 8, 10-11(1958). Contrary to the principle of freedom of contract, the proposed rule would force parties to engage in settlement discussions with any party, including parties who are abusive, advocate irrelevant issues, negotiate in bad faith, or maintain irrational expectations. The public interest argument of NC WARN does not change the freedom of contract principle, as the Commission remains responsible for making decisions that ensure that the public interest is served by a settlement agreement that the Commission decides to approve. Experience shows that comprehensive settlements between utilities and the Public Staff have produced positive results for consumers, as amply demonstrated by the cases cited by NC WARN in Exhibit A of its Petition. These settlements achieved benefits for consumers that the Commission could not have ordered on its own, such as monetary concessions and regulatory conditions. Additionally, other parties had the opportunity to participate fully in the settlement negotiations by entering into confidentiality agreements to gain access to confidential information provided to the Public Staff, and by taking other steps that would have placed the party in a position to effectively participate in the settlement negotiations. This is the process that has been followed for years, and there is nothing opaque or secretive about it. Any perceived barriers to a party's participation in the process would have been largely of the party's own making.

Utilities

The utilities state that the proposed rule is not reasonable, not necessary to the Commission's implementation of the Public Utilities Act (Act), contrary to the Commission's statutory mandate to encourage settlement, and would effectively erode parties' well established practice of utilizing stipulations to resolve legal and factual issues in contested Commission proceedings. They cite several sections of the Act that establish the Commission's regulatory and rulemaking authority, as well as CUCA I. In addition, the utilities submit that several provisions of the proposed rule contradict the mandate of G.S. 62-69(a) that the Commission encourage settlements, including (1) proposed subsections (b)(1) and (b)(2) prohibiting the Commission from accepting a settlement until 10 days after the later of intervention or the filing of expert testimony would unreasonably constrain the timing and process for parties to file a settlement, and (2) proposed subsection (b)(6) prohibiting non-severability clauses fails to recognize that the Commission must independently find that the provisions of the settlement are in the public interest, citing CUCA I.

In addition, the utilities note that the Act establishes procedural rights to ensure that all interested parties can fully participate and advocate their interests in Commission proceedings, including G.S. 62-73, 101(c) and 94. In addition, under G.S. 62-79(a), CUCA I, and CUCA II the rights of non-settling parties are protected by requiring that the Commission demonstrate to the appellate courts that it considered all the evidence and used its independent judgment before approving a nonunanimous settlement. The utilities opine that the elaborate procedural, hearing, and appeals process mandated by the Act is working today as designed.

Further, the utilities maintain that the proposed rule is unreasonable because it is based on a fundamental mischaracterization of the existing practice and procedure of resolving contested Commission proceedings. They cite as examples NC WARN's allegations in its Petition and public statements that the settlement process is "unfair and nontransparent," that NC WARN has been "unfairly impeded from participating fully" in proceedings in which it has intervened, that settlements are presented to the Commission as a "fait accompli," and that "secret agreements" result in a lack of transparency. The utilities counter that the settlement of proceedings is a well-established and valuable practice, citing Estate of Barber v. Guilford County Sheriff's Dep't, 161 N.C. App. 658, 661, 589 S.E.2d 433, 435 (2003). Moreover, the utilities submit that compromise by settlement allows the utility, the Public Staff, and other parties to avoid protracted and contentious litigation, to narrow the disputed issues before the Commission, and, in certain cases, to resolve or eliminate conflicting testimony on a given issue. The utilities contend that this is a valuable process for large and small utilities alike. Further, settlements are not a "fait accompli," as the Commission is free to require evidence in support of them, and to accept or reject them as it deems appropriate based on the public interest.

The utilities also contend that the substantive provisions of the proposed rule are either not workable or are unnecessary under the Commission's practices and procedures. They state as an example that proposed subsections (b)(1) and (b)(2) would be unworkable in cases where separate public hearings are not scheduled other than at the opening of the expert witness hearing, or where the Commission determines there is no need for a public witness or expert witness hearing due to lack of protest, or if there is not 10 days between the last public witness hearing and the expert witness hearing. In addition, the utilities state that proposed subsection (b)(3), requiring that all parties be given "the opportunity to participate" in settlement negotiations, would present an impracticable obstacle to the resolution of contested matters before the Commission, without offering any discernable additional benefit. They state that their doors are always open for engaging in good faith and constructive settlement discussions with any and all parties. However, the utilities state that they have determined in certain circumstances that a party's interests and advocacy are completely irreconcilable to the utilities' fundamental position, making it unlikely that settlement discussions would be productive. Based on this experience, the utilities contend that there is neither authority nor benefit in attempting to force parties whose goals and interests are completely contrary to engage in settlement discussions with each other.

With respect to proposed subsection (b)(4), the utilities state that this provision also is unnecessary. They contend that the Act provides parties significant procedural and due process rights to contest stipulations either in testimony, at a hearing or in proposed orders or briefs. Similarly, the utilities submit that proposed subsection (b)(5) is unnecessary because Commission Rule R1-24(c) provides that the Commission may require proof of the facts stipulated to by parties, notwithstanding the stipulation.

In addition, the utilities maintain that proposed subsection (b)(6) is unreasonable and unworkable. They state that non-severability clauses are essential to protect a party's right to revert to its original position if a settlement is not approved by the Commission. Moreover, subsection (c) of the proposed rule, which would encourage timely discovery in Commission proceedings, is also unnecessary. The Commission provides clear guidance in its procedural orders at the outset of a given case regarding the timing and scope of discovery.

Further, the utilities contend that proposed subsection (d) is unreasonable and potentially unworkable to the extent that it is inconsistent with parties' rights under North Carolina law to protect trade secret and other confidential information from public disclosure. They also note that the Commission or any party can challenge a designation of confidentiality.

In conclusion, the utilities request that the Commission dismiss NC WARN's petition.

NCSEA

NCSEA states that settlements should be encouraged, and that transparency promotes public discourse about energy issues, and public confidence, both of which advance the public interest. NCSEA recommends that the Commission consider using prehearing conferences more frequently, or perhaps requiring them in complex proceedings, such as rate cases and mergers. Further, if the Commission is inclined to modify its rules, NCSEA recommends modernizing Commission Rule R1-20 as shown in Exhibits A and B attached to its comments, which are redlined and clean versions of Commission Rule R1-20 that incorporates NCSEA's proposed changes as well as comments to provide context for the proposed changes. NCSEA states that its proposed language updates Commission Rule R1-20 to include language from several sources, including the Rules Implementing Statewide Mediated Settlement Conferences in Superior Court Civil Actions, the General Rules of Practice for the Superior and District Courts, the South Carolina statutes governing that state's Office of Regulatory Staff, and the now-repealed Rules of the North Carolina Supreme Court Implementing the Electric Supplier Territorial Dispute Mediation Program.

NC WARN

NC WARN filed letters from Citizens Action Coalition, Indianapolis, Indiana, Alliance for Energy Democracy, Weaverville, North Carolina, and Institute for Local Self-Reliance, Minneapolis, Minnesota, in support of its proposed rules. In summary, these organizations state their support for the inclusion of all parties in settlement negotiations and greater transparency in settlement agreements. In addition, NC WARN states that further research indicates that no other commission has adopted rules regulating settlements, and that a rule adopted by the Commission could serve as a model for other jurisdictions.

Summary of Reply Comments

CUCA

CUCA states that it has been an active participant in the existing rate case settlement process and believes that, in most circumstances, the process has worked well. It cites as examples settlements in the last DEC and DEP rate cases in Docket Nos. E-7, Sub 1026 and E-2, Sub 1023, respectively, and PSNC's rate case in Docket No. G-5, Sub 565. CUCA further notes that it participated in lengthy settlement discussions with DNCP in its recent rate case, Docket No. E-22, Sub 532, but that despite good faith bargaining a settlement that included all the parties was not reached.

CUCA states that confidentiality of the settlement negotiations is essential to the goal of full and frank discussions. Further, requiring parties to participate in a more formalized structure would be contrary to the confidential and voluntary nature of settlement talks. CUCA states that a settlement is an "offer" to the Commission, supported by competent evidence, that the proposed settlement constitutes a fair and reasonable balancing of the interests of both the utility and its consumers. Thus, the Commission retains plenary power to accept or reject the proposed settlement. CUCA believes that the current, more informal and confidentiality-protected process of settlement is the better way to proceed, and that the sound exercise of the Commission's discretion, rather than a hard and fast rule, is the better way to handle settlements that occur near the start of scheduled hearings.

CUCA states that a significant barrier to NC WARN's participation in the settlement process is NC WARN's staunch refusal to execute appropriate confidentiality agreements. CUCA further states that the utilities and CUCA would be unwilling to have another party participate in settlement negotiations if that party has not executed a confidentiality agreement.

In addition, CUCA states that it reviewed the initial comments filed by the utilities and the Public Staff and agrees with those comments, and it adopts the initial comments of those parties as the balance of its reply comments in this matter.

Public Staff

The Public Staff agrees with NCSEA that prehearing conferences could be used more frequently with positive results, but notes that there is no one-size-fits-all timeline or procedure for settlement discussions. In addition, the Public Staff states that NCSEA's proposed changes to Commission Rule R1-20 to require the Public Staff to act as a facilitator or mediator to resolve disputes and issues, and to advise all participants of circumstances bearing on possible bias, prejudice, or partiality of the Public Staff would be unworkable, as it would hinder the Public Staff's ability to perform its statutory responsibilities on behalf of the using and consuming public. The Public Staff states that it cannot serve as both a neutral facilitator and consumer advocate in the same docket, and that the current version of Rule R1-20 properly recognizes that convening and conducting prehearing conferences is solely a Commission function.

Further, the Public Staff states that the principles and policies underlying the existing settlement process are well established and are more than sufficient to protect the interests of parties who are prepared to participate in good faith. As a result, the Public Staff continues to maintain that the process should not be restricted by additional rules.

NC WARN

NC WARN states that in major electric cases, such as rate cases and mergers, it and similar public advocacy groups have been shut out of settlement discussions. Further, NC WARN reiterates its contention that too many of the settlements are presented to the Commission as a "fait accompli" with "all or nothing" provisions demanding the Commission accept the settlement in its entirety, and that the Commission should always make its own independent findings of fact and conclusions of law, rather than indiscriminately adopt a settlement agreement.

In addition, NC WARN asserts that the utilities believe Commission Rule R1-24(c) authorizes the utilities to settle with some but not all of the parties. In response, NC WARN cites the Court's statement in CUCA I that it "encourages all parties to seek such resolution through open, honest and equitable negotiation." (Emphasis added). Id., at 466, 500 S.E.2d at 717.

NC WARN states that neither the Public Staff nor the utilities offer substantive arguments concerning the time constraints in the proposed rule, only that they are contrary to current practice. It states that the goal of the proposed rule is to encourage open and transparent negotiations, and to insure that no parties are put in an unequitable position of having settlements and stipulated agreements filed before testimony is filed, or a day or two before an expert witness hearing, and that these goals reflect the Act and case law provisions that encourage settlement by all parties.

Discussion and Decision

The Commission agrees with the parties that settlements should be encouraged, and that the Commission should do all it lawfully and reasonably can to facilitate the parties' efforts to reach a full and fair settlement. On the other hand, the Commission as the decision maker cannot be involved in the settlement discussions, or make and enforce rules that have a substantive effect on the parties' settlement negotiations. These parameters are firmly established by the Act and other considerations. In addition, there is a long Commission history in which settlement negotiations have proceeded in a fair, cooperative and productive manner, resulting in hundreds of settlements that the Commission has independently reviewed and subsequently approved, in whole or in part, as serving the public interest. In light of the success of existing settlement practices, the Commission is hesitant to attempt a major "fix" of the process when it is not broken. In addition, the Commission must abide by the following legal requirements and principles.

Pursuant to G.S. 62-69(a), the Commission "shall encourage the parties and their counsel to make and enter stipulations of record." Further, "The Commission may make informal disposition of any contested proceeding by stipulation, agreed settlement, consent order or default." However, irrespective of whether the case is settled or fully litigated, the Commission's orders must be based on competent, material and substantial evidence. G.S. 62-65. In addition, the Commission's authority to accept or reject a nonunanimous settlement is governed by the standards set by the North Carolina Supreme Court in CUCA I and 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. 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation "requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] ... satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." Id., at 231-32, 524 S.E.2d at 16.

Where practicable, the Commission applies the rules of evidence used in the superior courts in civil matters. See G.S. 62-65(a). Pursuant to Rule 408 of the North Carolina Rules of Evidence, in pertinent part, "Evidence of conduct or evidence of statements made in compromise negotiations is likewise not admissible." G.S. 8C-1, Rule 408. There are two main reasons for prohibiting settlement discussions to be used as evidence: (1) to encourage open and frank settlement discussions by the parties regarding the evidence supporting their positions, the strengths and weaknesses of their positions and their parameters for accepting a settlement; and (2) to prevent the court, jury or Commission from knowing the lowest amount or least relief that any party might be willing to accept in resolution of the case.

Thus, in establishing and enforcing any settlement guidelines, the Commission must walk the fine line between encouraging all parties to resolve their differences prior to trial, while avoiding the exercise of any control over the structure or content of the settlement discussions. The Commission's analysis of the best means for striking the proper balance between these principles leads the Commission to the following conclusions regarding the particular rule provisions proposed by NC WARN.

Subsection (a)

> The Commission encourages the parties, as defined in Rule R1-3, to settle matters between and among themselves in order to focus on the issues required to be heard by the Commission. However, settlements and

stipulated agreements filed with the Commission shall be supported by credible evidence, expert testimony, and exhibits.

As previously discussed, G.S. 62-69(a) requires the Commission to encourage settlements. Therefore, the first sentence of subsection (a) of the proposed rule is unnecessary. The second sentence of subsection (a) is repeated as a part of proposed subsection (b)(5), and will be discussed subsequently.

Subsections (b)(1) and (b)(2)

(1) The Commission will not accept a settlement or stipulated agreement between or among parties until 10 days after the deadline for intervention or the filing of expert testimony established by the Commission, whichever comes later.

(2) The Commission will not accept a settlement or stipulated agreement until 10 days after the last public hearing, excluding the opportunity for public testimony at the beginning of the evidentiary hearing, if public hearings are scheduled as part of the proceeding.

These rules would create an unworkably narrow window for settlements to be filed. Under the Commission's rules, direct testimony is generally due 10-15 days before the expert witness hearing. See Commission Rules R1-24(g)(2), R1-17(f) and R8-55(h)(i). The Commission's scheduling orders typically set the date for filing direct testimony as 15 days prior to the hearing. Thus, if testimony was due on April 1 and the expert witness hearing was set for April 16, the settling parties would have to file their testimony on April 1, but could not file their settlement before April 11. It appears that NC WARN would like to prevent the Public Staff and other parties from signing a settlement agreement prior to 10 days after filing their testimony. However, the proposed rule would not prohibit that, as the parties could sign a settlement agreement but hold the filing of the agreement until 10 days after filing their testimony. In addition, one likely consequence of the proposed rule would be to discourage the parties from continuing to negotiate towards a settlement of the case after they have filed their testimony. Once a party has filed its direct testimony stating its litigation position on the utility's application, that party has staked out a somewhat rigid position and may find it difficult to settle for any relief that is significantly less.

In addition, one of the chief benefits of a settlement is that it saves parties and ratepayers the expense of fully litigating a case. For example, one of the most labor intensive and, consequently, expensive aspects of litigation is the preparation of testimony. To require a party to file litigation testimony, as opposed to settlement testimony, perhaps as productive settlement discussions are continuing and a settlement is nigh, would be wasteful.

With regard to the proposed prohibition against filing a settlement before the last public witness hearing scheduled in the docket, this would create the same unworkably narrow window for settlement discussions as under proposed (b)(1). The dates set for public witness hearings in a particular docket and the date for the expert witness hearing have no particular timing or relationship. Rather, there are several factors that bear upon the dates set by the Commission for public witness hearings. These factors include the availability of hearing locations, a preference for grouping the hearings on consecutive dates if the locations of the hearings are in the same area of the state, and the Commissioners' schedules. Thus, there is no set time frame for public witness hearings. They could be several weeks prior to the expert witness hearing, or they could be during the same week as the expert witness hearing. For example, in the PSNC rate case, Docket No. G-5, Sub 565, the last public witness hearing was held on August 29, and the evidentiary hearing began on August 30. In the DEC rate case, E-7, Sub 1026, the last public witness hearing was held on July 2, and the expert witness hearing began on July 8.

In addition, there is no compelling reason to require parties to withhold the filing of their settlement agreement until after the date of the last public witness hearing. Similar to the prohibition in proposed subsection (b)(1), it appears that NC WARN would like to prevent parties from signing a settlement agreement prior to the last public witness hearing. However, the proposed rule would not do so, as the parties could sign a settlement agreement but hold the filing of the agreement until after the final public witness hearing. In addition, the Commission encourages parties to begin settlement discussions as soon as they are sufficiently knowledgeable about the facts and issues, and to conclude them as quickly as reasonably possible. This helps provide the Commission and non-settling parties with sufficient time to review and understand the terms of the settlement before the expert witness hearing. Requiring that a settlement not be reached prior to the last public witness hearing would be an arbitrary and counterproductive rule.

Perhaps NC WARN is concerned that a public witness hearing held after the parties have filed a settlement gives the impression that the hearing is just "going through the motions" to give the appearance of listening to ratepayers, even though the parties, or some of them, have reached a settlement. If that is NC WARN's concern, then NC WARN is ignoring the main purpose of the public witness hearing – to provide the opportunity for ratepayers to express their views and present evidence to the Commission, which has not approved the settlement, and continues to have a duty to consider all the evidence and exercise its independent judgment to decide the case in the public interest.

Subsection (b)(3)

> A statement shall accompany the settlement or stipulated agreement stating that all of the parties had the opportunity to participate in settlement negotiations, and that all of the parties had the opportunity to review and comment on the settlement or stipulated agreement at least 10 days before it was filed with the Commission.

With regard to the first portion of this proposed rule, the Commission agrees that it is preferable when manageable for all parties to have an opportunity to participate in the settlement negotiations. However, the Commission also agrees with the Public Staff that it is not manageable to have a party that has not signed a confidentiality agreement participate in settlement negotiations. Therefore, the Commission does not expect the Public Staff or utilities to include a party who has declined to sign a confidentiality agreement. Further, it sometimes becomes apparent during settlement discussions that a participating party perhaps is not truly interested in settling the case or has settlement interests that hamper the ability or likelihood of other participants to reach agreement on issues they could otherwise resolve. Thus, when it is no longer fruitful to continue to include a party in the settlement meetings, the other parties must have the freedom to exclude the party. On the other hand, settlement discussions are a two-way street. Any party can initiate settlement discussions with any other party, a few of the parties or with all of the parties.

The Commission acknowledges that the Public Staff is in somewhat of a different position than a private party litigant. The Public Staff represents ratepayers and must be guided by the public interest, whereas most private litigants represent only their particular interests. However, the Public Staff is a state agency completely independent of the Commission. The Commission does not and cannot control how the Public Staff investigates dockets, the decisions it makes about how best to represent ratepayers, or the decision it makes about who to include in settlement negotiations or what it believes to be the fairness of a particular settlement agreement. To do so would place the Commission in the unethical position of controlling the ratepayer advocate while also serving as the decision maker. Similarly, the Attorney General's Office (AGO) frequently intervenes to represent consumers in the public interest, under the authority granted in G.S. 62-20. Again, the AGO is a separate agency from the Commission, and the Commission has no control over its investigations, decisions about how best to represent ratepayers, or decisions about who it chooses to negotiate with or its view as to the fairness of a particular settlement agreement.

With regard to the last portion of proposed subsection (b)(3), the requirement to provide non-settling parties with the settlement agreement at least 10 days before it is filed would create the same unacceptable narrow window for settlement negotiations as previously discussed with regard to subsections (b)(1) and (b)(2). The rule would effectively end settlement discussions if a settlement had not been reached at least 10 days prior to the expert witness hearing. As stated earlier, the Commission encourages parties to begin settlement discussions early and conclude them as quickly as reasonably possible, but requiring that they be concluded at least 10 days prior to the expert witness hearing would be counterproductive.

<u>Subsection (b)(4)</u>

> Parties, including those not entering into the settlement or stipulated agreement, are encouraged to file statements within 10 days of the date as to which provisions of the settlement or stipulated agreement they support, oppose, or have no position on.

The Commission agrees with the general proposition of this proposed subsection and welcomes statements, especially by the non-settling parties, regarding the parties' position on a proposed settlement agreement. However, the Commission concludes that it is unnecessary to adopt a Commission rule on this point.

<u>Subsection (b)(5)</u>

> The parties entering into the settlement or stipulated agreement shall file expert testimony and exhibits providing support for the filing.

As previously noted, G.S. 62-65 requires that the Commission's orders be based on competent, material and substantial evidence. In practice, the settling parties typically file testimony and exhibits in support of their settlement agreement. Therefore, the Commission concludes that it is unnecessary to adopt a Commission rule on this point.

Subsection (b)(6)

> The Commission will not accept settlements or stipulated agreements which require the settlement or stipulated agreement to be approved in its entirety or not at all.

Non-severability clauses are a standard provision in settlement agreements and other contracts. They are intended to protect the benefit of the bargain that each of the settling parties negotiated to receive. For example, the Public Staff may agree to allow the utility to defer certain costs in return for the utility giving up its claim to recover construction work in progress (CWIP). If the Commission "cherry picks" the settlement by accepting the parties' agreement on cost deferral but rejecting their agreement on CWIP, then the balance of the bargain negotiated by the parties may be seriously impaired.

Of course, a non-severability clause does not prevent the Commission from approving the settlement provisions that it concludes are in the public interest, and rejecting those that are not. Rather, it protects the parties by allowing them to decide whether the Commission's partial approval of the settlement is acceptable to them. If not, then the parties can decide to withdraw from the settlement.

As noted above, CUCA I and CUCA II require the Commission to exercise its independent judgment to determine whether all of the provisions of a settlement agreement are in the public interest. As a result, the Commission does not view itself as being bound by the non-severability clauses included in settlement agreements. Indeed, the Commission has demonstrated its independence from such provisions in several major dockets by adding conditions of its own, or rejecting proposed settlement provisions. See Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, Docket No. E-7, Sub 795 (2006); and Order Granting General Rate Increase, Docket No. E-7, Sub 989 (2012).

Finally, and perhaps most importantly, the Commission does not have the legal authority to prohibit parties from including a non-severability clause in their settlement agreements.

With regard to NC WARN's concern about "secret agreements," the Commission cannot know about or attempt to regulate every tangential agreement or stipulation entered into by the parties. It is not infrequent that a party intervenes in a docket to obtain relief on a very narrow issue that affects only that party, and the utility resolves that issue with that party without filing a settlement agreement. Nonetheless, the Commission does not impliedly or otherwise condone any "secret agreement," and especially if such an agreement might impact the position of other parties to the docket. In addition, NC WARN's assertions with regard to secret agreements are not supported by the example it gave, the Duke/Progress merger proceeding, Docket Nos. E-2, Sub 998 and E-7, Sub 986. In that docket, the Commission issued a Post-Hearing Order Requiring Verified Information on November 2, 2011. The Order, among other things, required the merger Applicants to file a copy of all settlements related to the proposed merger. The Applicants subsequently filed 17 settlement agreements under seal. In response to a request under the Public Records Act for public disclosure of the settlement agreements, the Applicants contended that public release of the settlement agreements would chill future settlement negotiations and impede the public policy in favor of settlements. The Commission rejected this argument and required disclosure of the settlement agreements, although the Applicants were allowed to redact provisions that the Commission determined were trade secrets exempted from public disclosure by G.S. 132-1.2. See Final Order on Public Records Act Request, Docket Nos. E-2, Sub 998 and E-7, Sub 986 (August 14, 2012).

Subsection (c)

> Parties are encouraged to submit data requests or pursue other discovery as soon as possible so the information to all parties is roughly equivalent prior to the review of the settlement or stipulated agreement. Late-filed discovery requests will not provide grounds to extend the settlement review period.

In its orders scheduling hearings the Commission sets out very specific time limitations and other guidelines for the parties to follow in conducting discovery. In addition, the scheduling orders include the following statement: "A party shall not be granted an extension of time to pursue discovery because of that party's late intervention or other delay in initiating discovery." Thus, the Commission concludes that it is unnecessary to adopt a Commission rule addressing these points.

Subsection (d)

> All parties should carefully examine all filings in order to minimize, if not eliminate, filings under the seal of confidentiality or trade secret.

Pursuant to the North Carolina Public Records Act, G.S. 132-1.2, a party has the right to file information under seal when the information constitutes a trade secret. The seminal case involving a Commission determination under the Act is State ex rel. Utilities Comm'n v. MCI Telecommunications Corp. (MCI), 132 N.C. App. 625, 514 S.E. 2d 276 (1999). The appeal in MCI arose from Docket Nos. P-100, Sub 133 and P-55, Sub 1022. MCI and other competing local providers (CLPs), objected to public disclosure of certain information that the Commission required the CLPs to provide in their monthly access line reports, which were entitled Questions for Competing Carriers (QCC). In particular, QCC Nos. 11, 12 and 13 required the CLPs to provide detailed plans of when they intended to enter the market for local telephone service and how they intended to provide business and residential customers with such service. In its initial order concerning the matter, on October 21, 1997, the Commission acknowledged that the answers to QCC Nos. 12 and 13 might involve trade secrets. The Commission stated:

> CLPs may, of course, assert their privilege to designate answers to any questions as confidential trade secrets, but they should be prepared at the time of filing to submit a detailed and cogent statement of the reasons therefore, in accordance with the provisions of G.S. 132-1.2(4). (Emphasis in original)

Order Concerning Confidentiality of Report Filings (MCI Order), at p. 2.

The Commission has similarly recognized that the disclosure of certain information could affect a public utility's ability to negotiate with providers of products and services, and the utility's negotiations in other contexts. As a result, the Commission has approved the maintenance of the proprietary nature of such trade secret information. On the other hand, the Commission has also recognized the value of making more information public so as to improve customer confidence in the expenditures made by public utilities and, in the present context, settlement agreements.

In addition, the Commission urges all parties to pay close attention to that portion of G.S. 132-6(c) that provides: "No request to inspect, examine or obtain copies of public records shall be denied on the grounds that confidential information is commingled with the requested non-confidential information." This provision makes it incumbent on the party claiming confidentiality to redact from each page filed with the Commission only that information that is exempt from disclosure under the Public Records Act. When parties mark as confidential and file under seal the full text of each page of a document, even though much of the text is not trade secret information, that impedes the public's and the other parties' right to have information that does not belong under seal. Thus, the Commission takes this opportunity to reaffirm the requirement of the MCI Order that parties submit a detailed and cogent statement of the reasons for filing information under seal, and the requirement of G.S. 132-6(c) that parties refrain from including non-confidential information in their claim for confidentiality of trade secrets.

Finally, the Commission appreciates NCSEA's comments regarding prehearing conferences. However, prehearing conferences have little to do with facilitating settlement agreements. Instead, a prehearing conference is a tool by which the Commission can discuss with the parties measures that might be taken to organize the presentation of witnesses and evidence in order to streamline the expert witness hearing. As the decision maker, the Commission has the authority to supervise the entire decision-making process. If necessary, this includes giving the parties direction regarding legal and ethical requirements pertinent to settlement negotiations. However, as previously discussed, the Commission generally refrains from exercising direct control over the settlement negotiation process, other than procedural matters, such as extensions of time, that might assist the parties in their effort to negotiate a settlement.

Conclusion

Based on the foregoing and the record, the Commission is not persuaded that there is good cause to adopt the settlement guidelines proposed by NC WARN. As a result, the Commission concludes that NC WARN's Petition for Rulemaking should be dismissed.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the __1st__ day of March, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-100, SUB 118
DOCKET NO. EC-67, SUB 36
DOCKET NO. EC-83, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Joint Notice and Petition for Waivers by North Carolina Electric Membership Corporation and GreenCo Solutions, Inc.	)))	ORDER GRANTING WAIVERS OF COMMISSION RULE R8-67 AND PROVIDING OTHER RELIEF

BY THE COMMISSION: On August 27, 2008, in Docket No. E-100, Sub 118, the Commission issued an Order that, among other things, granted a waiver of certain filing requirements in Commission Rule R8-67 to allow GreenCo Solutions, Inc. (GreenCo), to file renewable energy and energy efficiency portfolio standard (REPS) compliance plans and REPS compliance reports on an aggregated basis on behalf of GreenCo's member electric membership corporations (EMCs).

On November 16, 2017, in Docket Nos. EC-67, Sub 36, and EC-83, Sub 2, the North Carolina Electric Membership Corporation (NCEMC) and GreenCo (together, Petitioners), filed a joint notice and petition for waivers. Petitioners state that NCEMC is a generation and transmission cooperative responsible for supplying power to 25 of the 26 distribution EMCs headquartered in North Carolina, and that GreenCo is a non-profit organization formed to assist its member EMCs in complying with their REPS compliance obligations. Petitioners further state that the respective boards of directors of NCEMC and GreenCo have approved, subject to regulatory approval sought in this proceeding, the substitution of NCEMC for GreenCo as utility compliance aggregator for 24 EMCs and the Town of Oak City (Oak City) effective January 1, 2018. Petitioners further indicate that after the substitution, GreenCo will wind down its operations over the next 12 months and dissolve.

Petitioners identify the following EMCs as "REPS Compliance Members," on whose behalf NCEMC would provide REPS compliance services: Albemarle EMC, Brunswick EMC, Cape Hatteras EMC, Carteret-Craven EMC, Central EMC, Edgecombe-Martin 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, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union EMC, and Wake EMC. In addition, Petitioners identify the following electric service providers on whose behalf GreenCo performs REPS compliance services, as being included in NCEMC's proposed REPS compliance services: Mecklenburg Electrical Cooperative, headquartered in Chase, Virginia; Broad River Electrical Cooperative, headquartered in Gaffney, South Carolina; and Oak City, which is a wholesale customer of Edgecombe-Martin EMC and is included in Edgecombe-Martin EMC's REPS reporting and compliance (collectively, with the above-named EMCs, NCEMC's REPS Compliance Customers).

To carry out Petitioners' plan to substitute NCEMC for GreenCo, Petitioners requests that the Commission 1) authorize NCEMC to serve as the utility compliance aggregator for NCEMC's REPS Compliance Customers; 2) continue to waive the annual REPS filing requirements of Commission Rule R8-67 for each of NCEMC's REPS Compliance Customers so long as NCEMC serves as utility compliance aggregator; and waive the requirement of Commission Rule R8-67(d)(1) that a renewable energy certificate (REC) be purchased by an electric power supplier within three years of the date that the REC was earned so that NCEMC may purchase and use for future REPS compliance the REC bank held by NCEMC's REPS Compliance Customers. In support of its request, Petitioners state that NCEMC will make the filings required by Commission Rule R8-67 and take over from GreenCo any and all energy efficiency program development and management services. In addition, Petitioners state that all executory REC purchase and sale agreements wherein GreenCo is the buyer will be assigned to NCEMC and, effective January 1, 2018, NCEMC will begin purchasing RECs for REPS compliance on behalf of NCEMC's REPS Compliance Customers. Petitioners further state that NCEMC will purchase the RECs currently held in bank by NCEMC's REPS Compliance Customers, and that the plan to substitute NCEMC for GreenCo will facilitate NCEMC's REPS Compliance Customers' overall compliance with the REPS requirements. Finally, Petitioners request that the Commission consider their petition on an expedited basis in order to allow the substitution of NCEMC for GreenCo to be implemented on January 1, 2018.

On December 8, 2017, the Public Staff filed a letter summarizing the Petitioners' filing, and stating that after review of the Petitioners' filing, the Public Staff does not have any objections to the Commission granting the relief requested. The Public Staff further states that in response to its inquiry, Petitioners submitted information indicating that both Mecklenburg Electrical Cooperative and Broad River Electrical Cooperative consented to the substitution plan.

No other person has sought to intervene in this proceeding, or otherwise raised an objection to granting the Petitioners' requested relief.

The Commission carefully considered Petitioners' request to allow NCEMC to be substituted for GreenCo as utility compliance aggregator for NCEMC's REPS Compliance Customers. The Commission agrees with Petitioners that the implementation of Petitioners' plan to substitute NCEMC for GreenCo will facilitate NCEMC's REPS Compliance Customers' overall compliance with the REPS. Therefore, the Commission finds that good cause exists to grant Petitioners' request to substitute NCEMC for GreenCo as utility compliance aggregator for NCEMC's REPS Compliance Customers.

The Commission next considers Petitioners' request for a waiver of the requirement that that RECs be purchased by the electric power supplier within three years of the date they were earned. The Commission first adopted this requirement to effectuate the policy goals of the REPS, recognizing that a "market flush with 'stale' RECs would hinder the development of renewable energy" and that such a result would be contrary to the legislative intent behind enactment of the REPS. Order Adopting Final Rules, at p. 46, Docket No. E-100, Sub 113, issued February 29, 2008. As Petitioners have appropriately identified, the Commission has previously waived the three-year requirement of Commission Rule R8-67(d)(1) in cases involving the transfer of RECs between electric power suppliers or between an electric supplier and a utility compliance aggregator when the original purchase of the RECs in question was made within three years of the RECs having been earned. See Order Approving Waiver Request, Docket No. E-100, Sub 113, issued December 3, 2014. Petitioners' request involves similar considerations, and the Commission determines that granting Petitioners' requested waiver of the three-year requirement of Commission Rule R8-67(d)(1) would be consistent with the policy rationale supporting the adoption of that rule provision. Therefore, the Commission finds that good cause exists to grant Petitioners' requested one-time waiver of Rule R8-67(d)(1) so that NCEMC can buy the REC banks held by NCEMC's REPS Compliance Customers in furtherance of the plan to substitute NCEMC for GreenCo as utility compliance aggregator.

Finally, the Commission considers Petitioners' request to continue to waive the REPS reporting requirements for NCEMC's REPS Compliance Customers. The Commission agrees with Petitioners that continuing this waiver will facilitate compliance with the reporting requirements by NCEMC's REPS Compliance Customers. In addition, similar to the Commission's initial determination to allow GreenCo to perform consolidated reporting, the Commission determines that NCEMC's annual REPS reports and plans to-be-filed on behalf of NCEMC's REPS Compliance Customers, along with the other reports required of individual electric service providers and utility compliance aggregators, provide the Commission with all the data and information required by Commission Rule R8-67. Therefore, the Commission finds that good cause exists to grant Petitioners' requested ongoing waiver of the reporting requirements of Rule R8-67, so long as NCEMC continues to serve as utility compliance aggregator on behalf of NCEMC's REPS Compliance Customers.

IT IS, THEREFORE, ORDERED AS FOLLOWS:

1. That, effective January 1, 2018, NCEMC shall be, and hereby is, authorized to serve as utility compliance aggregator on behalf of NCEMC's REPS Compliance Customers and to assume the REPS compliance services and related functions currently being performed by GreenCo;

2. That NCEMC shall be, and hereby is, granted a waiver of the requirement of Commission Rule R8-67(d)(1) that RECs used for REPS compliance be purchased within three years of the date that they were earned so that NCEMC can complete the one-time purchase of the RECs currently owned by NCEMC's REPS Compliance Customers and retire these RECs for future REPS compliance by NCEMC's REPS Compliance Customers; and

3. That NCEMC's REPS Compliance Customers shall be, and hereby are, granted a continuing waiver of the requirement in Commission Rule R8-67 to annually file individual REPS compliance plans and REPS compliance reports so long as NCEMC continues to serve as utility compliance aggregator on behalf of NCEMC's REPS Compliance Customers.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of December, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-100, SUB 147

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
2016 Integrated Resource Plans and Related) ORDER ACCEPTING SMART
2016 REPS Compliance Plans) GRID TECHNOLOGY PLANS

BY THE COMMISSION: On September 30, 2016, Dominion North Carolina Power (DNCP) filed its smart grid technology plan (SGTP) in the above-captioned docket. On October 3, 2016, Duke Energy Progress, LLC (DEP) and Duke Energy Carolinas, LLC (DEC) filed their SGTPs. (Collectively, DNCP, DEP, and DEC are referred to hereinafter as the electric utilities.) After several requests for extensions of time to file comments, which the Commission granted, comments were filed on December 19, 2016, by the Public Staff and the North Carolina Sustainable Energy Association (NCSEA). The Environmental Defense Fund (EDF) filed comments on December 20, 2016. On January 13, 2017, reply comments were filed by DNCP and jointly by DEP and DEC (Duke).

Background

By Orders dated April 11, 2012, and May 6, 2013, in Docket No. E-100, Sub 126, the Commission amended rules requiring electric utilities that file integrated resource plans (IRPs) to include in their IRPs information on how planned "smart grid" deployment would impact the utilities' resource needs. Commission Rule R8-60.1 requires the electric utilities to file SGTPs every two years with updates in the intervening years. The initial SGTPs were filed by the electric utilities on October 1, 2014. The Commission, in its Order dated November 5, 2015, approved these 2014 SGTPs. In addition to approving the SGTPs, the Commission ordered, (1) DEC, DEP, and Dominion to address in their 2016 SGTPs whether the Commission's Rules require updating to address customer and third party access to usage data, and (2) DEC to address the issue of AMI opt-outs relative to its current and planned AMI deployments by December 1, 2015.

The Commission stated in the 2015 Order that smart grid proceedings are intended to be informative, and the Commission does not anticipate using them to order utilities to make specific smart grid investments, nor are they a means by which utilities should seek to secure advance prudency reviews of smart grid investments.[1]

By Order dated June 13, 2016, in Docket No. E-100, Sub 126, the Commission amended Rules R8-60(i)(10) and R8-60.1, stating that the amended rules will better focus the SGTP proceedings as an informative effort to assist the Commission and parties in anticipating the potential impact of new technologies on customers.

[1] It should be noted, however, that G.S. 62-42 grants the Commission authority to order an investor-owned utility to make equipment improvements if necessary to assure that customers receive adequate and sufficient electric service.

Rule R8-60.1(c) states that

> For purposes of this Rule, smart grid technologies are as set forth in Rule R8-60(i)(10) and shall also include those that provide real-time, automated, interactive technologies that enable the optimization and/or operation of consumer devices and appliances, including metering of customer usage and providing customers with options to control their energy consumption.

Rule R8-60.1(c) lists the information to be included in each utility's SGTP. In summary, the rule requires a description of the technologies, goals, and objectives of each technology, the status and timeframe for completion of the project, and cost information. In addition, Rule R8-60.1(c)(7) requires additional details about plans and ongoing deployments of automated metering infrastructure (AMI).

Summary of Smart Grid Technology Plans

Duke Energy Carolinas

DEC identified 14 smart grid technology projects that it is implementing or planning to implement in the next five years:

1) Large C&I and Special Meter AMI Conversion
2) Walk-by Meter Reduction
3) Yukon Feeder Automation Upgrade
4) Distribution Management System (DMS) Consolidation Program
5) AMI to Distribution Outage Management System
6) Line Sensor Installation
7) Recloser Supervisory Controls and Data Acquisition (SCADA) Upgrades
8) Self-Healing Networks
9) Feeder Circuit Break SCADA Upgrades
10) Transmission Relay Upgrades
11) Annunciator Upgrades
12) AMI Phase 2
13) AMI Expansion 2015
14) Meter Data Management

DEC also identified four additional smart grid technologies actively under consideration: (1) AMI deployment; (2) usage alerts; (3) outage notifications; and (4) Pick Your Own Due Date.

In addition, DEC identified eight smart grid technology pilots and initiatives that are either underway or planned within the next two years. Those technologies include the following:

1) Distribution Energy Resources Management System (DERMS)
2) Integrated Voltage/Volt-Ampere Reactive Control (IVVC) Pre-Scale Deployment
3) Charlotte Automation & Integration Pre-Scale Deployment
4) Trip Saver Pre-Scale Deployment
5) Smart Meter Usage App
6) Pre-Pay Program

DEC discussed its ongoing work with microgrids and energy storage, including the McAlpine Microgrid and Mount Holly Microgrid projects, energy storage projects under development at the Rankin substation, the Marshall energy storage site, and the testing of home energy storage systems.

Addressing customer and third party access to customer usage data, DEC and DEP (collectively, Duke) indicated that they see merit in reviewing the Commission Rules, and stated that their foremost concerns are related to maintaining the privacy of customers' usage data. Duke proposed that if the Commission chooses to proceed with proposed rule changes, the Commission should open a separate docket and the process should be a collaborative effort among all interested intervening parties. Additionally, Duke noted that updates to Commission Rules would warrant updates to its Codes of Conduct in the areas involving affiliate transactions and data sharing.

With regard to AMI deployment, DEC indicated that, as of September 2016, it has cumulatively installed 527,391 AMI meters, an increase of approximately 252,260 AMI meters since its 2014 SGTP.

Duke Energy Progress

DEP's SGTP is similar to DEC's in content and format. DEP identified seven projects that it has already completed, is currently implementing, or is planning to implement in the next five years:

1) Self-Healing Networks
2) Yukon Feeder Automation Upgrade
3) Phasor Measurement Units
4) DMS Consolidation Program
5) Distribution System Demand Response
6) Feeder Segmentation
7) Condition-Based Monitoring Pilot

DEP also identified two additional smart grid technologies that are actively under consideration, including its Western Carolinas Energy Storage Analysis and Deployment Plan, in which DEP committed to working with its customers in the DEP-Western Region to provide access to demand-side management (DSM), energy efficiency, or other customer programs, and its efforts to construct at least 15 MW of solar and 5 MW of storage capacity. In addition, DEP discussed its evaluation of renewable energy and storage microgrids to serve remote customers in lieu of investing in traditional distribution infrastructure upgrades.

In addition, DEP identified three pilots and initiatives that are currently underway or planned within the next two years:

1) Trip Saver Pre-Scale Deployment
2) Condition-Based Monitoring – Pre-Scale Deployment
3) Urban Underground Automation – Raleigh

Like DEC, DEP includes the same discussion regarding its ongoing work with microgrids and energy storage, citing the same facilities as DEC did in its SGTP.

With regard to AMI deployment, DEP indicated that, as of September 2016, it has installed 56,637 AMI meters, an increase of approximately 1,930 AMI meters since its 2014 SGTP.

The Yukon Feeder Automation Upgrade, DMS Consolidation, and Self-Healing Networks projects appear in both DEC's and DEP's SGTPs. Several of DEC's and DEP's other projects are similar in scope and objective, reflecting the aligning of some of DEC and DEP's resources, planning objectives, and smart grid investments.

Dominion North Carolina Power

DNCP's SGTP included descriptions of its current and near-term smart grid activities, including the following:

1) Microgrid Demonstration and Research Project in Kitty Hawk, North Carolina
2) North Carolina Solar Study
3) Solar Partnership Program in Virginia
4) Electric Vehicle Pilot in Virginia
5) Dynamic Pricing Pilot Program in Virginia

DNCP indicated that similar to the process used for DNCP's IRP, its SGTP and activities are being developed and evaluated on a system-wide basis for the benefit of customers in both North Carolina and Virginia.

Addressing customer usage data access, DNCP indicated that it did not believe any rule revisions regarding access to customer usage data were necessary at this time, and provided additional information on the data available to DNCP's customers, the modes in which customers can access their data, the form and process for third party access authorization, and a summary of the modes to which customers can provide access.

With regard to AMI meters, Dominion initiated AMI demonstrations in Virginia in 2009 to evaluate different AMI technologies and different applications of the technology. Dominion indicated that as of September 14, 2016, it has a total of 373,471 AMI meters installed in its service territory, with 5,170 AMI meters installed in North Carolina with a predicted life span of 15 years. The number of AMI meters installed in DNCP's service territory has increased by about 113,000 since the filing of DNCP's 2014 SGTP.

COMMENTS AND REPLY COMMENTS

Comments of the Public Staff

The Public Staff's review of the 2016 SGTPs was performed in the context of the 2015 Smart Grid Order[1] and the 2016 Rules Order.[2] Based upon that review, the Public Staff stated that the utilities have complied with the requirements of Commission Rule R8-60.1.

According to the Public Staff, the 2015 Smart Grid Order addressed the continued debate over the acquisition, administration, and availability of customer usage data that in part is a direct product of the availability of AMI. The Public Staff noted that discussions continue on how such customer data should be made available to customers and third parties, as well as how that data can inform future investments in smart grid technologies. The Public Staff stated that the information provided by the electric utilities in response to the Commission's August 23, 2013 Order[3] is helpful for customers who wish to utilize the additional data. Further, the Public Staff contends that the continuing debate over customer usage data in large part provided impetus to address the smart grid rules. According to the Public Staff, the debate was, in many ways, resolved with the filing and eventual amendment of the smart grid rules in the 2016 Rules Order. The Public Staff stated that the 2016 SGTPs filed by the utilities comply with the 2016 Rules Order.

While the Public Staff does not believe that any further changes to the Commission's rules are necessary at this time, the Public Staff recommends that the Commission continue to require the electric utilities to update their responses to the questions posed in the Commission's August 23, 2013 Order and include those responses in future SGTPs and updates. In addition, the Public Staff does not oppose DEC's and DEP's recommendation that if the Commission chooses to address further rule changes related to customer and third-party access, the process should be a collaborative effort in a separate docket with all interested intervening parties.

Regarding the AMI metering opt-out issue, the Public Staff notes that none of the utilities included any discussion about customer options for opting out of AMI metering in their 2016 SGTPs. The Public Staff believes this is more a result of the activity associated with DEC's request for approval of an opt-out policy filed July 29, 2016, in Docket No. E-7, Sub 1115, which is currently pending before the Commission. The Public Staff requested information from DNCP on this matter. DNCP indicated that it currently offers an interim Non-Communicating Metering Option (NCMO) to customers, and that DNCP plans to seek Commission approval of a NCMO that will include a proposed charge for participating in the NCMO. Upon Commission approval, DNCP indicated it will inform customers who are currently participating in the Interim NCMO that they are required to enroll in the Commission approved NCMO, subject to any Commission approved fee, in order to continue using a non-communicating meter.

[1] Order Approving Smart Grid Technology Plans, Declining to Schedule a Hearing, And Requesting Comments on Rule Revision, Docket No. E-100, Sub 141 (November 5, 2015).

[2] Order Amending Rules, Docket No. E-100, Sub 126 (June 13, 2016).

[3] Order Requesting Additional Information and Declining to Initiate Rulemaking, Docket No. E-100, Sub 137 (August 23, 2013).

Comments of the Environmental Defense Fund

EDF comments primarily addressed the following issues as described below.

Impact of Renewables on Smart Grid Deployment

According to EDF, DEC and DEP (Duke) discussed in their 2014 SGTPs how the distribution grids are coping with increasing levels of distributed solar resources. In the 2014 SGTPs, Duke stated "While the recent growth in renewable energy is forecasted to continue at an increasing rate, no significant capability currently exists for the proactive management and optimization of distribution connected distributed generation." Duke also stated that it was studying this issue with Pacific Northwest National Laboratory (PNNL) and the study was completed and is available on PNNL's website. Duke's present SGTPs do not discuss the PNNL study. EDF recommends that the Commission should require Duke, in its next SGTP filing, to explain how the study impacts the integration of renewables and how Duke is dealing with this in its smart grid deployment.

Voltage Optimization

The Commission's 2015 Order[1] states:

> DEC and DEP are considering at least two approaches to managing voltage on the distribution grid: low-voltage power electronics and IVVC. In addition, DEP has already installed DSDR, and Dominion is evaluating smart meters as a means of controlling distribution system voltage. In their 2016 smart grid plans, DEC, DEP, and Dominion should compare these approaches (and others as appropriate) in terms of costs and benefits, both of which may be expressed, if necessary, in very broad and qualitative terms.

EDF states that the utilities' current SGTPs do not discuss this issue in any detail and present no information regarding the costs and benefits of the available technologies for managing voltage on the distribution grid. Therefore, EDF recommends that the Commission should require the utilities to provide this information in their next SGTP filing. According to EDF, Duke and DNCP have both concluded that voltage optimization is a cost-effective tool for reducing customers' energy bills and for reducing greenhouse gas emissions. EDF commented that they have installed this technology for their utilities in other states. According to EDF, it believes that the Commission should require Duke and DNCP to include in their next SGTP filings detailed cost/benefit plans for installing voltage optimization in North Carolina.

[1] Order Approving Smart Grid Technology Plans, Declining to Schedule a Hearing, And Requesting Comments on Rule Revision, Docket No. E-100, Sub 141 (November 5, 2015).

Data Access

EDF states that the utilities' SGTPs provide very little information on customer access to energy usage data. EDF states that a vibrant, competitive marketplace is developing to take advantage of these opportunities and developing solutions for customers for energy management, energy efficiency and renewable energy adoption. According to EDF, the key enabler is customer access to their own usage data from the meter and the ability to share that data with energy management and service providers, also known as "third parties," of their choice, which translate and synthesize usage data into convenient, actionable steps for consumers to manage. EDF contends that the real game changer in the residential sector has been the availability of continuous energy usage information made available by AMI meters, which are able to record consumption data in near real-time, reported in intervals of an hour or less. Energy use varies greatly across households. EDF states that the detailed understanding of each home's energy use enabled by AMI opens the door to highly effective strategies for managing energy use and helping consumers save money – particularly those on time-varying rates where the time period of the consumption has a significant impact on bills.

The Commission's Order in the 2015 SGTP docket states that, if any party believes that changes are needed to the Commission's rules on data access, such party can propose rule changes in the 2016 SGTP docket. EDF states that it helped develop a protocol for customer access to energy usage information for use in Illinois. This protocol contains guidelines for customer access to information, the recommended time intervals for providing the information, confidentiality, third-party access, etc. EDF recommends that the Commission develop a similar protocol for North Carolina by implementing a rulemaking in this docket. EDF further states that it would be very helpful for the Commission to develop a data usage protocol because smart meters are becoming more prevalent and recent advances in technology enable greater and more convenient access to energy usage data. EDF notes that the Commission has expressed a need for utilities to develop a tariff for customers to opt-out of AMI meters, and developing a data access rule should go hand-in-hand with developing the opt-out rule. According to EDF, the need for both of these items is driven by increasing AMI meter deployment.

Innovative Rate Plans

EDF contends that innovative rate planning is an area that is rapidly changing as more rate studies across the country become available. The U.S. Department of Energy (DOE) required utilities that received smart grid stimulus funding to conduct and report on the energy savings from innovative rate plans.[1] EDF states that the Commission should examine this information and open a new proceeding to examine how much energy savings would be available to customers if they had smart meters and new innovative rate plans. In addition, EDF states that the utilities should provide information regarding the cost-benefit analysis they used to show how much the benefits of smart meters would increase when they are paired with effective electricity pricing (rates) that

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[1] U.S. DOE, Final Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies (November 2016), available at:
https://www.smartgrid.gov/recovery_act/overview/consumer_behavior_studies.html/renewable_and_distributed_systems_integration_program.html

adjust consumer behavior, an example being rates that encourage energy consumption during periods of off-peak energy demand.

Metrics to Measure Performance of Smart Grid Technologies

According to EDF, the Commission should monitor more closely how successfully the utilities are utilizing new grid modernization technologies. EDF suggests the Commission can do so by requiring the utilities to propose metrics in their next SGTP filings to measure the performance of these new technologies, and the Commission can use these metrics when the utilities seek cost recovery in rate cases. EDF notes that these metrics would enable the Commission and stakeholders to determine how well the smart grid technologies are performing – in other words, the benefits of the smart grid technologies. This would help determine whether the technologies are cost-effective. According to EDF, the utilities may be investing significant sums in smart grid technologies, and this type of real-time prudency evaluation would be much better than the traditional after-the-fact prudency review. EDF recommends that the Commission establish a collaborative process with interested parties to develop the metrics which utilities would report on in future SGTPs, such as energy savings from voltage optimization; number and percentage of distribution circuits and substations with voltage optimization installed; greenhouse gas (GHG) emission reductions from voltage optimization; and the categories of energy usage data provided to customers.

Comments of the North Carolina Sustainable Energy Association

NCSEA's comments were focused on the data access issue as described below.

Data Access

Commission Rule R8-60.1 – Smart Grid Technology Plans and Filings – states that every two years each utility subject to Commission Rule R8-60(i)(10) shall file with the Commission its Biennial smart grid technology plan. Commission Rule R8-60.1(c)(3) sets forth the contents that are required to be included in SGTPs. The Rule specifically states that:

> (3) For all smart grid technologies currently being deployed or scheduled for implementation within the next five years:
>
> . . .
>
> > (iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.
> > (v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

In the 2014 SGTP proceeding, NCSEA commented that "[i]n response to the directives concerning how the utilities will transfer information between themselves and customers and how third parties will implement or utilize any portion of the technology, the utilities all failed to provide sufficient information."[1] In its comments, NCSEA states that while each of the utilities has made improvements in its 2016 SGTP, DEC in particular still fails to adequately address the transfer of information between it and the customer (although it does address the transfer of information between the customer's meter and the utility) and the transfer of information between it and third parties.

According to NCSEA, DEC discusses two projects in its 2016 SGTP that involve the deployment of AMI meters to certain customers who had been bypassed during DEC's initial AMI deployment.[2] For both projects, in response to the requirement of Rule R8-60.1(c)(3)(iv) to describe "how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information[,]" DEC describes the security measures it has put in place to protect customer information. However, according to NCSEA, DEC fails to explain how the technology transfers information from DEC to the customer. Similarly, in response to the requirement of Rule R8-60.1(c)(3)(v) to describe "how third parties will implement or utilize any portion of the technology," NCSEA states that DEC fails to even note that third parties make use of information from AMI meters.

NCSEA notes that DEC indicates in its 2016 SGTP that AMI meters provide customers:

> The ability to access day prior electric usage information via the internet-based Customer Portal. The Portal displays usage information up to and including prior day usage. Customers can view daily and average energy usage by billing cycle or month. Customers can also view average energy usage by day-of-week, and hourly energy usage by day or week . . .

Further, NCSEA notes that DEC indicates that its customers "have the ability to download their hourly usage data from the Customer Portal in a .CSV format." Similarly, DNCP's customers with AMI meters can use the utility's online customer portal "to view and download 30-minute interval data related to energy usage[.]"[3] However, according to NCSEA, DEP's 56,637 customers with AMI meters do not currently have access to similar granular information about their energy consumption.[4]

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[1] Comments of NCSEA and EDF, p. 4, Docket No. E-100, Sub 141 (January 9, 2015).

[2] See Duke Energy Carolinas 2016 Smart Grid Technology Plan, pp. 7-11, Docket No. E-100, Sub 147 (October 3, 2016).

[3] NCSEA Comments, Exhibit A (DNCP Response to NCSEA Data Request 2-2), Docket No. E-100, Sub 147.

[4] Id., Exhibit B (DEP Response to NCSEA Data Request 3-1).

NCSEA notes that DEC discusses the development of their Smart Meter Usage App program, which appears to indicate that the utility has concluded that an analysis of energy consumption data can provide insights to consumers, and that customers want this type of information. While NCSEA applauds DEC for taking the initiative to develop a program that provides consumers with this type of analysis, NCSEA notes that many such programs already exist.[1] However, these programs require easy and secure access to machine-readable granular energy consumption data that is currently not easily accessible to third-party software developers that have been authorized to receive the data by consumers.

NCSEA's Proposed Data Access Rule

In the 2014 SGTP proceeding, the Commission directed the utilities "to address in their 2016 SGTPs whether the Commission's rules should be updated at that time in order to address customer and third party access to usage data[,]" and went on to note that "if any party believes that rule changes are needed, they should file their proposed rule changes in the 2016 SGTP docket." In their SGTPs, DEC and DEP state that they "do see merit in reviewing the Commission Rules related to customer and third party access to usage data for potential updates[.]" DNCP; however, "does not recommend any revision to the Commission's rules that require updating to facilitate customer access to their utility data."

NCSEA commented that it agrees with DEC and DEP that there is merit in reviewing the Commission Rules related to customer and third-party access to usage data. According to NCSEA, combined, DEC, DEP, and DNCP have deployed nearly 590,000 AMI meters in their respective North Carolina service territories that are capable of providing granular energy consumption data that can be analyzed and provide insights to consumers about their energy consumption habits. While not in and of itself an energy efficiency measure, NCSEA stated that data access enables consumers to identify energy efficiency measures that could be most impactful based on their energy consumption habits.

To this end, and pursuant to the Commission's E-100, Sub 141 Order,[2] NCSEA proposed a new Commission Rule R8-51.1.[3] NCSEA's proposed rule would require the electric utilities to provide 24 months of energy usage data in an electronic machine-readable format at no charge as a part of their basic service. NCSEA's proposed rule further would require the utilities to have a standard form that can be submitted electronically for consumers to authorize the release of their energy consumption data to third parties. Finally, the proposed rule would hold the utilities

[1] NCSEA further questions whether it is an efficient use of utility funds, for which the utility will surely request cost recovery in a rate application, to develop a duplicative software program that provides the same services as existing software programs. NCSEA believes that the development of such software is clearly outside the utility's core business of providing electricity and is better left to venture capitalists and start-up technology companies.

[2] Order Approving Smart Grid Technology Plans, Declining to Schedule a Hearing, and Requesting Comments on Rule Revision, Docket No. E-100, Sub 141 p. 19 (November 5, 2015).

[3] NCSEA Comments, Exhibit C, Docket No. E-100, Sub 147 (December 19, 2016).

harmless if a third party who has been authorized to receive consumer energy usage data misuses the data in any manner. AMI meters provide the utilities with granular energy consumption data, and NCSEA states that the Commission should require the utilities to provide consumers and authorized third parties with easy access to this data.

Reply Comments of DEC & DEP (Duke)

Reply to EDF Comments:

Impact of Renewables on Smart Grid Deployment

On page 1 of its comments, EDF states that Duke did not discuss the 2014 Pacific Northwest National Laboratory (PNNL) study of the impacts of solar photovoltaic generation in their 2016 SGTPs and asks the Commission to require Duke to "explain how the study impacts the integration of renewables and how Duke is dealing with this in smart grid deployment." The PNNL study was outlined in detail in Duke's 2014 SGTPs, along with the study's conclusion that "the variability and penetration level of photovoltaic systems show a trend of increasing integration costs at successively higher penetration levels." Because that study was released in March 2014, and included in the 2014 SGTP, Duke indicated it did not see any reason to again discuss the 2014 PNNL study in its 2016 SGTPs.

In its 2016 SGTPs, Duke did address the management of increasing levels of renewables as it relates to smart grid investments through the detailed descriptions of projects such as the Yukon Feeder Automation Upgrade, Distributed Energy Resources Management System, Phasor Measurement Units, and various Emerging Technology Trends. Duke stated that it will continue to detail the smart grid investments that specifically address renewable integration within the corresponding project descriptions in future SGTPs. According to Duke, it continues to investigate the impacts of more renewables connecting to the distribution and transmission systems, and does not object to a discussion regarding how this impacts the smart grid investments in future SGTPs.

Voltage Optimization

EDF asserts in its comments that the Commission should require Duke to provide greater details and cost/benefit analyses for voltage optimization in its next SGTPs. In compliance with the Commission's November 5, 2015 SGTP Order in Docket No. E-100, Sub 141, Duke discussed the approaches to managing voltage on the distribution grid in its 2016 SGTPs Appendix A – Distribution Voltage Control. Additionally, as agreed to in the settlement with EDF and provided for in the Commission's September 29, 2016 Order Approving Merger Subject to Regulatory Conditions and Code of Conduct in Docket Nos. E-2, Sub 1095; E-7, Sub 1100; and G-9, Sub 682, Duke stated it will provide cost-benefit analyses for Integrated Volt-VAR Control to include conservation voltage reduction in its 2018 biennial SGTPs.

Data Access

EDF asserts on page 4 of its comments that the SGTPs provide very little information about customer access to energy usage data. In its reply comments, Duke stated that it respectfully disagrees, maintaining that this topic was detailed in each respective SGTP, under the requirements of R8-60.1(c)(7)(iv). Regarding providing customer usage data to third parties, Duke indicated its response to requirement R8-60.1(c)(3)(v) was accurate as it relates to DEC and DEP's current situation in North Carolina, as of the filing of the 2016 SGTPs, in that third parties do not utilize any of Duke's currently deployed smart grid technologies, nor does Duke currently transfer any customer data from smart grid technologies to third parties. If and when DEC or DEP engage with third parties and collaborate on implementing or utilizing smart grid technologies, Duke indicated that information will be captured appropriately within the North Carolina SGTPs.

Innovative Rate Plans

On page 7 of its comments, EDF asks the Commission to open a new proceeding to investigate innovative rate plans. Duke states that it does not agree with a need for such a proceeding. As to EDF's comments on analyzing the cost-effectiveness of a smart grid deployment, Duke notes that it has proposed AMI deployment, which is justified without assumptions related to new rates. Duke further notes that it currently offers time-varying rate plans for both residential and non-residential customers, so customers choosing to participate may do so today. In addition, Duke suggests it will review rate design changes, potentially including new rate structures, in future rate case proceedings.

Metrics to Measure Performance of Smart Grid Technologies

On pages 8-9 of its comments, EDF proposes that the Commission develop metrics to support a move to "real-time prudency evaluation." Duke indicates in its reply comments that it believes the current prudency tests are appropriate, and that there is no need to engage in a collaborative stakeholder process to update the prudency review standards at this time, especially as smart grid technology investments are quickly becoming the new standard, and not as unique as initially considered over a decade ago.

Reply to NCSEA Comments:

Data Access

According to Duke, NCSEA claims that DEC fails to adequately address the transfer of information between it and the customer. However, in the second section of NCSEA's comments, NCSEA quotes from the DEC SGTP detailing how the utility provides AMI meter data to its customers. Duke stated in its reply comments that DEC clearly references how it provides customers with AMI meter data in the 2016 SGTP, pp. 35-36, in response to the requirement R8-60.1(c)(7)(iv) to provide "A discussion of what AMI services or functions are currently being utilized, as well as any plans for implementing other AMI services or functions within the next two years." Duke notes that details on information provided to customers is also outlined in response to question 2 in Appendix B[1] – Responses to Questions in Commission's August 23, 2013 Order in Docket No. E-100, Sub 137.

Duke points out that NCSEA continues to assert, in its comments, that DEC fails to address requirement R8-60.1(c)(3)(v) to describe how third parties will implement or utilize any portion of the technology. In response, Duke's reply comments state:

> The Companies' response to requirement R8-60.1(c)(3)(v) was accurate as it relates to DEC and DEP's current situation in North Carolina, as of the filing of the 2016 SGTPs, in that third parties do not utilize any of the Companies' currently deployed smart grid technologies, nor do the Companies currently transfer any customer data from smart grid technologies to third parties. If and when DEC or DEP engage with third parties and collaborate on implementing or utilizing smart grid technologies, that information will be captured appropriately within the North Carolina SGTPs.

According to Duke, NCSEA references (on pages 3-4 of its comments) DEC's Smart Meter Usage App program and even "applauds DEC for taking the initiative to develop a program that provides consumers with this type of analysis." However, NCSEA questions whether this type of program "is better left to venture capitalists and start-up technology companies." Duke notes that NCSEA makes this statement assuming that DEC is developing this app in-house, when in fact the utility clearly outlines in the 2016 SGTP that a request for proposals (RFP) is underway for this program, and vendor selection is expected by the end of 2016. Duke indicates that it recognizes the efficiency of partnering with a vendor that has already developed this programming.

NCSEA's Proposed Data Access Rule

According to Duke, while DEC and DEP may see merit in reviewing the Commission Rules related to customer and third-party access to usage data, NCSEA's singular, end-state objective of providing real-time customer usage data to third parties is very narrowly focused. Duke indicates that there are many other factors that must be considered related to investment requirements, customer privacy, liability, authorizations, Duke's Codes of Conduct and affiliate transactions. Therefore, a separate docket was proposed by Duke if the Commission chooses to pursue this topic.

The Public Staff, DEC, DEP, DNCP, and NCSEA, along with representatives from a third-party conglomerate organization, Mission:Data, invited by NCSEA, participated in discussions during 2016 to begin understanding the needs to update the Commission Rules on data access. Duke contends that as each of the utility participants already have processes in place to provide data to customers and authorized third parties, NCSEA's proposed wholesale rule changes seem unnecessary. Therefore, Duke does not object to continuing discussions on updating the Commission Rules related to data access, but believes that the weight and complexity of this topic deserves its own docket.

[1] Duke Energy Carolinas 2016 Smart Grid Technology Plan, Docket No. E-100, Sub 147 (October 3, 2016).

Additionally, Duke believes that the costs to develop the systems and interfaces to provide customer data directly to third parties, manage the customer authorization process, and handle ongoing data requests for third parties should not necessarily be funded by utility customers. This is especially the case when there are already systems and processes in place for providing third parties with customer usage data, and NCSEA is requesting specific data in different formats for its third-party constituents.

In conclusion, Duke submits that its 2016 SGTPs meet the requirement of all applicable statutes, Commission Rules, and Commission orders and should be accepted as filed. Furthermore, Duke asserts that additional recommendations from intervening parties are unwarranted, and that the requests for the same should be denied.

Reply Comments of DNCP

Data Access

DNCP noted that it agrees with the Public Staff that NCSEA's proposed customer usage data access rule is not needed at this time. According to DNCP, Appendix A to its 2016 SGTP demonstrates that DNCP already has appropriate procedures in place to provide customers and third-parties access to customer usage data. DNCP states that it provides substantial historical customer usage information with retail customer bills for each current billing period, and additional information for up to the prior 12 billing periods.[1] Retail customers electing to participate in DNCP's eBill (electronic billing) program have online access to an exact copy of the bill mailed to DNCP's paper bill customers. In addition, DNCP notes that retail customers can request and receive usage information by using DNCP's customer portal to view their last 12 bills, access 18 months of historical usage, and view 30-minute interval data (where applicable), by contacting DNCP via telephone to discuss their usage with a Company employee, or by requesting via telephone or letter that a copy of their bill or an account statement covering 18 months of usage be mailed to them to their address on record.[2] DNCP asserts that NCSEA makes no allegations (nor has the Public Staff or any customer of DNCP alleged) that DNCP's existing data access policies and processes are unreasonable or fail to provide customers with sufficient access to their own customer usage data.

[1] DNCP 2016 SGTP, at Appendix A, pp. 10-11, explains that this information includes beginning and ending billing period dates, beginning and ending meter readings, number of days in billing period, total kilowatt hours (kWh), and (where applicable by rate) on peak kWh, total demand (kW), on peak kW, off peak kW, kilo quantity hours (KQH), and reactive kilovolt ampere (RKVA).

[2] *Id.* at p. 12

With regard to third-party access to customer usage information, DNCP states that it already has procedures in place to allow for such access. As discussed in DNCP's 2016 SGTP, customers may authorize the release to a third party their usage information by mailing a written release to DNCP authorizing release of their usage information to a third party, or customers may obtain their own usage information and provide it themselves to a third party by any mode they deem appropriate.[1]

In sum, DNCP indicated it does not agree with NCSEA and EDF that a new customer data access rule is needed. DNCP stated support for the Public Staff's recommendation for the Commission to direct the electric utilities to update their answers to the questions contained in the Commission's August 23, 2013 Order (Docket No. E-100, Sub 137) in their future biennial SGTPs. Finally, DNCP commented that to the extent that the Commission requires parties to further address customer and third-party data access, collaboration with NCSEA and other parties can occur without a rulemaking proceeding. DNCP noted that should a rulemaking proceeding be initiated, DNCP agrees that a collaborative process may be appropriate and it would participate, as directed by the Commission.

Other

With regard to EDF's additional proposals, DNCP stated that it does not support EDF's recommendations that the Commission impose additional cost/benefit requirements on DNCP's future SGTPs based upon regulatory decisions and smart grid investments by other utilities in other jurisdictions. DNCP also indicated it does not support EDF's recommendations to require the utilities to analyze alternative rate designs adopted by other utilities, or establish new performance metrics related to DNCP's planned smart grid investments based upon developments in other jurisdictions. DNCP points out that the Commission has clarified, and DNCP agrees, that the purpose of this proceeding is not to mandate specific new smart grid investments.[2]

In conclusion, DNCP respectfully requests that the Commission accept DNCP's 2016 SGTP as reasonable and in compliance with Rule R8-60.1, and deny NCSEA's and EDF's requests for additional proceedings and requirements.

DISCUSSION AND DECISIONS

The Commission finds the SGTPs filed by DEC, DEP, and DNCP to be informative and in compliance with the requirements of Commission Rule R8-60.1. Issues specific to the electric utilities' SGTPs in this docket are addressed below.

[1] Id., at pp. 12-13

[2] Order Approving Smart Grid Technology Plans, Declining to Schedule a Hearing, and Requesting Comments on Rule Revision, Docket No. E-100, Sub 141, at 19-20 (November 5, 2015).

GENERAL ORDERS – ELECTRIC

AMI Metering Opt-Out

In its Order dated November 5, 2015, approving the electric utilities' SGTPs (Docket No. E-100, Sub 141), the Commission ordered "That DEC shall address the issue of AMI opt-outs relative to its current and planned AMI deployments by December 1, 2015, and parties may file reply comments by January 22, 2016."

The Public Staff commented that none of the electric utilities included any discussion about customer options for opting out of AMI metering in their 2016 SGTPs. According to the Public Staff, this may be the result of activity associated with DEC's request for approval of an opt-out policy, as noted below. The Public Staff requested information from DNCP on this matter. In response, DNCP indicated that it currently offers an interim Non-Communicating Metering Option to customers. According to DNCP, however, it plans to seek Commission approval of a Non-Communicating Meter Option that will include a proposed charge for participating.

On July 29, 2016, DEC filed an application in Docket No. E-7, Sub 1115 for approval of a Manually Read Meter Rider (Rider MRM) to be paid by DEC customers who choose not to have DEC install AMI meters to measure their electric service. The Commission has received comments and reply comments on the Rider MRM as proposed by DEC and DEC's proposed tariff is pending before the Commission.

According to DEC, in 2016 it began evaluating the case for continuing with incremental smart meter deployments of about 150,000 per year, or moving forward with a project to replace all remaining non-AMI meters with smart meters. DEP stated that as of September 2016 it has installed 56,637 AMI meters, a relatively small number. Similarly, DNCP reported that as of September 2016 it has installed a total of 5,170 AMI meters in North Carolina.

Commission Rule R8-60.1(c)(3), subsections (ii), (iii) and (vii), require that SGTPs include the following information, among other things, for technologies currently being deployed or scheduled for implementation within the next five years:

> (ii) The status and timeframe for completion.
>
> (iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at the time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.
>
> (vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

DEC included this information in its SGTP for its Large Commercial & Industrial and Special Meter AMI Conversion and related Walk-by Meter Reduction projects. Excluding these projects, however, the Commission notes that neither DEC, DEP nor DNCP included the above information in their 2016 SGTPs with regard to any future plans for deployment of AMI meters.

The Commission interprets this to mean that DEC, DEP and DNCP currently have no plans to replace existing meters with AMI meters, either incrementally or on full scale, during the next five years. As a result, the Commission expects DEC, DEP and DNCP to provide the Commission with the above information, as well as any other required information, in their SGTP filings prior to implementing an incremental or full scale effort to replace existing meters with AMI meters.

Innovative Rate Plans

EDF asserts in its comments that the Commission should open a new proceeding to investigate how much energy savings would be available to customers if they had smart meters and innovative rate plans. In addition, EDF recommends that the utilities provide information regarding the cost-benefit analysis they used to show how much the benefits of smart meters would increase when they are paired with effective electricity pricing (rates) that effect changes in consumer behavior.

The electric utilities do not support this recommendation. DNCP stated in reply comments that it does not support EDF's recommendation to require the utilities to analyze alternative rate designs adopted by other utilities. In addition, Duke made the following comments opposing EDF's recommendation.

> The Companies do not agree with a need for such a proceeding. As to EDF's comments on analyzing the cost-effectiveness of a smart grid deployment, the Companies have proposed AMI deployment, which is justified without assumptions related to new rates. The Companies currently offer time-varying rate plans for both residential and non-residential customers, so customers choosing to participate may do so today. In addition, the Companies will review rate design changes, potentially including new rate structures, in future rate proceedings.

The Commission is convinced that existing rate plans are sufficiently designed to encourage behavioral changes that will result in energy savings for consumers. Therefore, the Commission is not persuaded that it should open a new proceeding to investigate innovative rate plans. The Commission, however, encourages the utilities to thoroughly evaluate the effectiveness of current rate designs and structures to support consumer choice and behaviors.

Pacific Northwest National Laboratory Study

EDF asserts in its comments that the Commission should require Duke, in its next SGTP filing, to explain how the PNNL study[1] impacts the integration of renewables and how Duke is dealing with this in its smart grid development.

[1] Duke Energy Photovoltaic Integration Study: Carolinas Service Areas (March 2014), available at http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23226.pdf.

As noted in the PNNL study, Duke commissioned the study to simulate the effects of high-PV penetration rates and to initiate the process of quantifying the impacts. The study results stand on their own. The study is a good example of the commitment of the utilities and industry to inform the ongoing efforts to effectively integrate distributed generation. The Commission takes judicial notice of the full record in Docket No. E-100, Sub 101 including the Interconnection Standards and Agreements approved in 2015.[1] Further, Duke states in its reply comments:

> In their 2016 SGTPs, the Companies did address the management of increasing levels of renewables as it relates to smart grid investments through the detailed descriptions of projects such as the Yukon Feeder Automation Upgrade, Distributed Energy Resources Management System, Phasor Measurement Units, and various Emerging Technology Trends. The Companies will continue to detail the smart grid investments that specifically address renewable integration within the corresponding project descriptions in future SGTPs. The Companies have continued to investigate the impacts of more renewables connecting to the distribution and transmission systems, and do not object to discussing how this impacts the smart grid investments in future SGTPs.

The Commission concludes that it is unnecessary for Duke to specifically address the PNNL study in its next SGTP filing. However, the Commission expects each of the electric utilities to discuss, in future SGTPs, how the integration of distributed generation impacts their decisions on smart grid investments.

Voltage Optimization

EDF asserts in its comments that the Commission should require Duke and DNCP to include in their next SGTP filings detailed cost/benefit plans for installing voltage optimization in North Carolina. In support of this recommendation, EDF notes that contrary to the Commission's 2015 SGTP Order,[2] the utilities' current SGTPs do not discuss this issue in any detail and present no information regarding the costs and benefits of the available technologies for managing voltage on the distribution grid.

In the portion of the Commission's 2015 SGTP Order addressing costs and benefits, the Commission suggested that broad and qualitative terms are appropriate.[3] The Commission requested in the 2015 Order that parties file comments suggesting ways the smart grid rules could be amended to enhance the informative aspects of future smart grid proceedings while reducing the litigious aspects of the current rules. NCSEA filed comments on December 1, 2015 (Docket No. E-100, Sub 126) advocating rule changes including a requirement for utilities to describe the technologies and provide the cost-benefit analyses for the technologies that it has decided to deploy, as well as those it has decided not to deploy in the next five years. On January 29, 2016, in Docket No. E-100, Sub 141, the Public Staff filed proposed rule revisions on behalf of all the

[1] Order Approving Revised Interconnection Standard, Docket No. E-100, Sub 101(May 15, 2015), and Order Approving Interconnection Agreement, Docket No. E-100, Sub 101(May 18, 2015).

[2] Order Approving Smart Grid Technology Plans, Declining to Schedule a Hearing, and Requesting Comments on Rule Revision, Docket No. E-100, Sub 141(November 5, 2015).

[3] Id., at p. 16.

parties (including NCSEA). The proposed amendments, among other things, provided that the revised rules would require the utility to provide the analysis it used to decide whether to pursue (or not pursue) a particular smart grid initiative and the schedule of its planned capital expenditures, rather than provide a "cost-benefit analysis" for each planned smart grid investment. By Order[1] dated June 13, 2016, Rule R8-60.1 was amended and the current Rule states:

> For all smart grid technologies actively under consideration for implementation within the next five years, the smart grid technology plan shall include a description of the technologies, including the goals and objectives of the technologies, as well as a descriptive summary of any completed analysis used by the utility in assessing the smart grid technology.[2]

Duke states in its reply comments:

> In compliance with the Commission's November 5, 2015 SGTP Order in Docket No. E-100, Sub 141, the Companies discussed the approaches to managing voltage on the distribution grid in their 2016 SGTPs Appendix A – Distribution Voltage Control. Additionally, as agreed to in the settlement with EDF and provided for in the Commission's September 29, 2016 Order Approving Merger Subject to Regulatory Conditions and Code of Conduct in Docket Nos. E-2, Sub 1095; E-7, Sub 1100; and G-9, Sub 682, Duke Energy will provide cost-benefit analyses for Integrated Volt-VAR Control to include conservation voltage reduction in the 2018 biennial SGTPs.

The Commission finds the discussion of Distribution Voltage Control included in Appendix A of Duke's SGTPs useful and responsive to the Commission's 2015 Order. As referenced by Duke in Appendix A, the Commission also acknowledges the benefit and cost components included in Distribution System Demand Response Program annual reports[3] filed with this Commission.

DNCP provided information on the technologies it employs for controlling voltage on the distribution grid in Appendix C of its 2016 SGTP. Reference is made to the North Carolina Solar Study that DNCP initiated in 2016 to evaluate system impacts on circuits with high levels of solar penetration. As noted on page 5 of DNCP's SGTP, the results of the study will be used by DNCP to assess operating conditions, evaluate system voltage on circuits with concentrated solar DG, and inform potential operational solutions to mitigate potential system impacts. Phase I of the study consists of detailed data analysis and is expected to continue through 2017.

The Commission is not persuaded that it needs to order Duke and DNCP to include in their future SGTP filings more detailed cost/benefit plans for installing voltage optimization in North Carolina. However, the Commission does expect DNCP to provide more details from the North

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[1] Order Amending Rules, Docket No. E-100, Sub 126 (June 13, 2016).

[2] Id., at Appendix B, p. 3.

[3] For example, Duke Energy Progress, LLC Annual Report for Distribution System Demand Response Program, Docket No. E-2, Sub 926 (June 22, 2016).

Carolina Solar Study in future SGTP filings to include the costs and benefits of solutions proposed to mitigate system impacts of distributed generation.

Metrics to Measure Performance of Smart Grid Technologies

EDF asserts that the Commission should monitor more closely how successfully the utilities are utilizing new grid modernization technologies. EDF goes on to suggest that the Commission can do so by requiring the utilities to propose metrics in their next SGTP filings to measure performance of these new technologies, and the Commission can use these metrics when the utilities seek cost recovery in rate cases. In other words, EDF is suggesting that a real-time prudency evaluation is better than the traditional after-the-fact prudency review. Each of the electric utilities opposed this recommendation.

The Commission appreciates EDF's interest in defining metrics that may be used to monitor how well the utilities are utilizing new grid modernization technologies. However, the Commission is of the opinion that the information required by Rule R8-60.1(c)(4) should be sufficient to inform the Commission prior to traditional cost recovery mechanisms. In particular, the Commission recognizes the requirement in the Rule[1] for "goals and objectives" of each technology deployed to be discussed in the SGTP. Therefore, the Commission is not persuaded that it should require the utilities to propose new metrics as recommended by EDF.

Customer Usage Data Access

In its Order dated November 5, 2015, in Docket No. E-100, Sub 141, approving smart grid technology plans, the Commission ordered "That DEC, DEP, and Dominion shall address in their 2016 SGTPs whether the Commission's Rules require updating in order to address customer and third party access to usage data."

DEC and DEP stated in their 2016 SGTPs that they see merit in reviewing the Commission rules related to customer and third-party access to usage data for potential updates. DNCP, however, indicated in its 2016 SGTP that rule revisions regarding access to customer usage data were not necessary at this time.

The Public Staff's comments referred to the amendment of the smart grid rules in the Commission's 2016 Rules Order and concluded that further changes to the Commission's rules are not necessary at this time. The Public Staff also stated that it does not oppose DEC's and DEP's recommendation that if the Commission chooses to address further rule changes related to customer and third-party access, the process should be a collaborative effort in a separate docket with all interested intervening parties.

[1] Rule R8-60.1(c)(4).

EDF asserts that the utilities' SGTPs provide very little information on customer access to energy usage data. EDF states that it helped develop a protocol for customer access to energy usage information for use in Illinois. The protocol contains guidelines for customer access to information, the recommended time intervals for providing the information, confidentiality, third-party access, etc. EDF recommends that the Commission develop a similar protocol for North Carolina by implementing a rulemaking in this docket.

NCSEA commented that it agrees with DEC and DEP that there is merit in reviewing the Commission rules related to customer and third-party access to usage data. NCSEA goes on to state:

> It is supportive of a collaborative effort to update the Commission's data access rules, but notes that it has been more than a year since the Commission requested that proposed rules be filed in the 2016 SFTP docket. Accordingly, all interested parties have had adequate notice that the Commission's data access rules would be examined and have had the opportunity to intervene in the present docket. As such, NCSEA submits that it is unnecessary to open a separate docket to consider the issue.

As such, and pursuant to the Commission's E-100, Sub 141 Order,[1] NCSEA proposed a new Commission rule[2] to address customer and third-party access to usage data.

In their reply comments, the utilities defend their current systems and processes as appropriate to address customer usage data access. DNCP indicated it does not agree with NCSEA and EDF that a new customer data access rule is needed. However, DNCP commented that if the Commission requires parties to further address customer and third-party data access, collaboration with NCSEA and other parties can occur without a rulemaking proceeding.

The Commission agrees with EDF's comments that AMI meters, which are able to record consumption data in near real-time, could have an important impact on the residential energy sector. The Commission takes special note of the AMI deployment referenced in DEC's SGTP, where DEC states that it began evaluating the case for continuing with incremental deployments or moving forward with a project to exchange all remaining non-AMI meters. As the utilities expand the use of AMI technologies across North Carolina, the Commission finds that it is imperative that protocols for customer access to energy usage information be properly developed and kept current, consistent with the value proposition of these new technologies.

The Commission recognizes the effort in 2016 by certain stakeholders to understand the need to update the Commission Rules on data access. DEC and DEP included the following statement in their reply comments:

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[1] Order Approving Smart Grid Technology Plans, Declining to Schedule a Hearing, and Requesting Comments on Rule Revision, Docket No. E-100, Sub 141, p. 19 (November 5, 2015).

[2] Proposed Commission Rule R8-51.1 (See NCSEA Comments, Exhibit C, Docket No. E-100, Sub 147, December 19, 2016).

> The Public Staff, DEC, DEP, DNCP, and NCSEA, along with representatives from a third-party conglomerate organization, Mission:Data, invited by NCSEA, participated in discussions during 2016 to begin understanding the need to update the Commission Rules on data access. As each of the utility participants already have processes in place to provide data to customers and authorized third-parties, NCSEA's proposed wholesale changes seemed unnecessary. Therefore, Duke does not object to continuing discussions on updating the Commission Rules related to data access, but believes the weight and complexity of this topic deserves its own docket.

The Commission encourages the electric utilities, the Public Staff, and all interested parties to continue meeting and discussing rule changes related to customer usage data and third-party access. The Commission recognizes there are many factors the stakeholders must consider when proposing rule changes to provide easy access to granular energy consumption data. These include, but are not limited to, customer privacy, liability, authorizations, Codes of Conduct, and affiliate transactions which should be appropriately addressed in the parties' discussions. Therefore, rather than initiating a formal rulemaking docket at this time, the Commission requests that Duke include a report on the discussions regarding potential rule changes in Duke's 2017 SGTPs.

The Commission appreciates NCSEA's efforts to develop and propose a new Commission Rule R8-51.1 addressing data access.[1] However, the Commission chooses not to offer discussion, findings, or conclusions on the proposed rule pending the above-referenced rulemaking discussions and report.

CONCLUSION

Based upon the record in this proceeding, and the comments of the Public Staff regarding the SGTPs submitted by DEC, DEP, and DNCP, the Commission hereby accepts the SGTPs filed by the utilities as complete and in compliance with the requirements set out in Commission Rule R8-60.1. The Commission orders DEC, DEP, and DNCP to update their responses to the questions posed in the Commission's August 23, 2013 Order and include those responses in future SGTP filings. Further, the Commission finds good cause to request that the electric utilities, the Public Staff, and all interested parties continue discussing potential rule changes related to customer data access, and that Duke include a report on those discussions in its 2017 SGTPs.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of March, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

[1] NCSEA Comments, Exhibit C, Docket No. E-100, Sub 147 (December 19, 2016).

DOCKET NO. E-100, SUB 147

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2016 Biennial Integrated Resource Plans and Related 2016 REPS Compliance Plans	)))	ORDER ACCEPTING INTEGRATED RESOURCE PLANS AND ACCEPTING REPS COMPLIANCE PLANS

HEARD: Monday, February 27, 2017, at 7:00 p.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Don M. Bailey, James G. Patterson, and Lyons Gray.

APPEARANCES:

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

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

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

Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation, NCRH 20/P.O. Box 1551, Raleigh, North Carolina 27602

For North Carolina Waste Awareness & Reduction Network:

John D. Runkle, 2121 Damascus Church Road, Chapel Hill, North Carolina 27516

For Southern Environmental Law Center:

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

For the Using and Consuming Public:

Lucy Edmondson, Staff Attorney, and Heather Finnell, Staff Attorney, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: Integrated Resource Planning (IRP) is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable electric service. IRP considers demand-side alternatives, including conservation, efficiency, and load management, as well as supply-side alternatives in the selection of resource options. Commission Rule R8-60 defines an overall framework within which the IRP process takes place in North Carolina. Analysis of the long-range need for future electric generating capacity pursuant to G.S. 62-110.1 is included in the Rule as a part of the IRP process.

General Statute (G.S.) 62-110.1(c) requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs" for electricity in this State. The Commission's analysis should include: (1) its estimate of the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) the extent, size, mix, and general location of generating plants; and (4) arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission (FERC). Further, G.S. 62-110.1 requires the Commission to consider this analysis in acting upon any petition for the issuance of a certificate for public convenience and necessity for construction of a generating facility. In addition, G.S. 62-110.1 requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly a report of its: 1) analysis and plan; (2) progress to date in carrying out such plan; and (3) program for the ensuing year in connection with such plan. G.S. 62-15(d) requires the Public Staff to assist the Commission in making its analysis and plan pursuant to G.S. 62-110.1.

G.S. 62-2(a)(3a) declares it a policy of the State to:

> assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills....

Session Law (S.L.) 2007-397 (Senate Bill 3), signed into law on August 20, 2007, amended G.S. 62-2(a) to add subsection (a)(10) that provides that it is the policy of North Carolina "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS)" that will: (1) diversify the resources used to reliably meet the energy needs of North Carolina's consumers, (2) provide greater energy security through the use of indigenous energy resources available in North Carolina, (3) encourage private investment in renewable energy and energy efficiency, and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, Senate Bill 3 further provides that "[e]ach electric power supplier to which G.S. 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval."[1]

Senate Bill 3 also defines demand-side management (DSM) as "activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electric use from peak to nonpeak demand periods" and defines an energy efficiency (EE) measure as "an equipment, physical or program change implemented after 1 January 2007 that results in less

[1] G.S. 62-133.9(c).

energy being used to perform the same function."[1] Energy Efficiency measures do not include DSM.

To meet the requirements of G.S. 62-110.1 and G.S. 62-2(a)(3a), the Commission conducts an annual investigation into the electric utilities' IRPs. Commission Rule R8-60 requires that each utility, to the extent that it is responsible for procurement of any or all of its individual power supply resources,[2] furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in Rule R8-60. In odd-numbered years, each of the electric utilities must file an annual report updating its most recently filed biennial report.

Further, Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a REPS compliance plan as part of each biennial and annual report. In addition, each biennial and annual report should (1) be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports, and (2) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p).

Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the utilities' biennial and annual reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. The Commission must schedule one or more hearings to receive public testimony.

2016 BIENNIAL REPORTS

This Order addresses the 2016 biennial reports (2016 IRPs) filed in Docket No. E-100, Sub 147, by Duke Energy Progress, LLC (DEP); Duke Energy Carolinas, LLC (DEC); and Dominion North Carolina Power (DNCP) (collectively, the investor-owned utilities, utilities or IOUs). In addition, this Order also addresses the REPS compliance plans filed by the IOUs.

The following parties have been allowed to intervene in this docket: Alevo USA, Inc. (Alevo); Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); Environmental Defense Fund (EDF); Grant Millin; Mid-Atlantic Renewable Energy Coalition (MAREC); North Carolina Sustainable Energy Association (NCSEA); North Carolina Waste Awareness and Reduction Network (NC WARN); Nucor Steel-Hertford (Nucor); and jointly, Southern Alliance for Clean Energy, Sierra Club, and the Natural Resources Defense Council (SACE, NRDC, and the Sierra Club). The Public Staff's intervention

[1] G.S. 62-133.8(a)(2) and (4).

[2] During the 2013 Session, the General Assembly enacted S.L. 2013-187 (House Bill 223), which exempted the EMCs from the requirements of G.S. 62-110.1(c) and G.S. 62-42, effective July 1, 2013. As a result, EMCs are no longer subject to the requirements of Rule R8-60 and are no longer required to submit IRPs to the Commission for review.

is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). The Attorney General's intervention is recognized pursuant to G.S. 62-20.

PROCEDURAL HISTORY

On April 29, 2016, DNCP filed its 2016 biennial IRP report and REPS compliance plan. DEC and DEP (collectively, Duke) filed their 2016 biennial IRP reports and REPS compliance plans on September 1, 2016.

On June 22, 2016, DNCP filed corrected pages to its IRP report.

On September 30, 2016, DEC and DEP filed corrected pages to their IRP reports.

On December 16, 2016, the Commission issued an Order Scheduling Public Hearing on 2016 IRP Plans and Related 2016 REPS Compliance Plans. That Order set the public witness hearing for 7:00 p.m. on February 27, 2017, in Raleigh.

On January 19, 2017, the Public Staff filed a motion for extension of time for the filing for petitions to intervene and initial comments to February 17, 2017, and the final date for serving discovery requests to January 24, 2017. The Commission granted this motion on January 20, 2017.

On January 19, 2017, DEC and DEP filed corrections to their 2016 REPS Compliance Plans.

On February 16, 2017, DEC and DEP filed late testimony on natural gas issues.

On February 17, 2017, initial comments were filed by the Public Staff, Grant Millin, NC WARN, NCSEA, MAREC, and jointly by SACE, NRDC and the Sierra Club.

On February 20, 2017, SACE, NRDC and the Sierra Club jointly filed Attachments A&B to their initial comments.

On February 22, 2017, the Public Staff filed an update to its February 17, 2017 comments regarding the DSM activations of DNCP.

On February 27, 2017, the public witness hearing was held in Raleigh, as scheduled.

On March 10, 2017, DEP filed notice that Sutton CT 1 was retired effective March 1, 2017, rather than in June 2017, as included in its IRP.

On April 17, 2017, NC WARN filed reply comments addressing DEC and DEP's late-filed testimony on natural gas issues.

On May 10, 2017, SACE, NRDC and the Sierra Club jointly filed reply comments, including the report "Duke Energy's Resource Plans for the Carolinas: Supplemental Analysis." Also on May 10, 2017, SACE, NRDC and the Sierra Club jointly filed a corrected version of Attachment D to its initial comments.

On May 10, 2017, reply comments were filed by DNCP and jointly by DEC and DEP.

PUBLIC HEARING

Pursuant to G.S. 62-110.1(c) the Commission held a public hearing in Raleigh on Monday, February 27, 2017, at 7:00 p.m., where 32 public witnesses spoke. In summary, the testimonies of the public witnesses focused on the need to encourage energy efficiency and clean renewable resources, such as solar and wind. A few of the witnesses commented on the value of integrating batteries, and other storage technologies, with the utilities' distributed resources. In addition, the witnesses encouraged the Commission to promote an economy and energy future focused on renewables and distributed energy systems. For example, one witness testified that the utilities are planning to build too much unnecessary and unjustified capacity without first maximizing clean energy and energy efficiency that has known benefits for clean air, clean water, and reduced cost for consumers. Other witnesses contended that coal and gas perpetuate climate issues because of greenhouse gas emissions, and further, that the utilities should stop investing in hydraulic fracked gas infrastructure, including the Atlantic Coast Pipeline.

DISCUSSION

The Commission finds and concludes that the record in this proceeding includes sufficient detail to allow the Commission to decide all contested issues without the necessity of a further hearing. The Commission commends the utilities and intervenors for the quality of presentation and analyses. The following sections summarize issues significant to the Integrated Resource Plans filed by the utilities and reflect the full record in the proceeding.

PEAK AND ENERGY FORECASTS

Public Staff Comments - Peak and Energy Forecasts

The Public Staff reviewed the 15-year peak and energy forecasts (2017–31) of DEP, DEC, and DNCP. The compound annual growth rates (CAGRs) for the forecasts are within the range of 0.9% to 1.5%. The Public Staff noted that all of the utilities used accepted econometric and end-use analytical models to forecast their peak and energy needs. They commented that with any forecasting methodology, there is a degree of uncertainty associated with models that rely, in part, on assumptions that certain historical trends or relationships will continue in the future.

In assessing the reasonableness of the forecasts, the Public Staff first compared the utilities' most recent weather-normalized peak loads to those forecasted in their 2015 IRP updates. The Public Staff then analyzed the accuracy of the utilities' peak demand and energy sales predictions in their 2009 IRPs by comparing them to their actual peak demands and energy sales. They commented that a review of past forecast errors can identify trends in the IOUs' forecasting and assist in assessing the reasonableness of the utilities' current and future forecasts. Finally, according to the Public Staff's comments, they reviewed the forecasts of other adjoining utilities in the VACAR region and the SERC Reliability Corporation.

The Public Staff commented that for the last 30 years, all three utilities predicted that their system peaks would occur in the summer. However, during January 2014, the IOUs reported several hourly peak loads that were greater than the summer peak loads that occurred later that year. In February 2015, DEC, DEP, and DNCP experienced all time system peaks. Following these events, DEC and DEP conducted a new resource adequacy study (reserve margin study) in 2015 and 2016, which was included with their 2016 IRPs. DEP and DEC's 2016 IRPs now forecast that the utilities are transitioning to winter peaking systems, with DEP turning winter peaking in 2017, and DEC becoming winter peaking in 2027. The Public Staff goes on to note that DNCP continues to predict that it will be a summer peaking system. In addition, SERC is reporting that its VACAR-South[1] (Carolinas region) winter peak after EE programs will exceed the summer peak until 2018, at which time the summer peak becomes dominant through 2025.

The Public Staff commented that in the 1980s a series of extremely cold winter days caused several winter peaks to be greater than the following summer peaks. This pattern was relatively short-lived, however, and the summer peaks returned to being the system peaks. The abnormally cold winter weather events in recent years and customers' responses to these temperatures have contributed to a sharp growth in winter electricity demands that lends support to the expectation that DEP and DEC may be transitioning towards becoming dual peaking or winter peaking systems. The Public Staff suggests, however, that caution is warranted before making conclusions on this trend.

According to the Public Staff, it is becoming apparent that both summer and winter peak demands have distinct impacts on the operation of the utility systems. Planning decisions going forward will need to evaluate how the IOUs respond to the unique characteristics of seasonal peak demands. The Public Staff notes that each IOU has attempted to independently address their winter and summer peak demands, in part by planning for future resources that can accommodate both winter and summer peak demand loads, as well as the energy requirements of its customers throughout the year.

Public Staff Comments - DEP's Peak and Energy Forecasts

The Public Staff commented that unlike previous years, DEP no longer considers its summer peak to be its system peak. DEP's 2016 IRP predicts its summer peak loads will have a lower Compound Annual Growth Rate (CAGR) of 1.0% as compared to the 1.2% CAGR of the winter peaks that include load reductions associated with projected EE programs and prior to the activation of any DSM programs. DEP's 2014 and 2012 IRPs predicted that its summer peaks would grow at a CAGR of 1.3% and 0.9%, respectively. Without the reduction in peak demand from implementation of its EE programs, DEP expects its summer peaks to grow at an average rate of 1.3%. DEP predicts that in 15 years, the load reductions from its cumulative new EE programs will reduce its annual summer peak load by approximately 7%, which is similar to its projection in its 2014 IRP. DEP assumes that it can actively reduce its summer peak load by using its DSM resources, which it considers a capacity resource.

DEP's forecast of its winter peak loads reflects a slightly higher CAGR of 1.2% than the CAGR of 1.0% for its summer peaks, with the annual difference in the seasonal peaks of

[1] 2016 SERC Regional Electricity Supply and Demand Projections, http://serc1.org/docs/default-source/committee/ec-reliability-review-subcommittee//rrs-annual-report/2016-regional-supply-and-demand -projections.pdf?sfvrsn=2.

approximately 200 MW. DEP predicts that in 15 years, the load reductions from its cumulative new EE programs will reduce its annual winter peak load by approximately 3% in 2031, which is significantly less than the 7% reduction predicted to be available for the summer peak. DEP projects that it will have less than half of the DSM resources to reduce its winter peak loads as compared to the DSM capacity available in summer.

DEP's energy sales, including reductions associated with its EE programs, are predicted to grow at a CAGR of 0.9%, which is similar to prior forecasts. DEP predicts that over the next 15 years, the MWh reductions from its EE programs will reduce its annual energy sales by approximately 1% in 2017, increasing to 3% in 2031.

The Public Staff commented that given the similarity of DEP's summer and winter peaks throughout the forecast period, their review of forecasting accuracy was focused on comparing the annual peak demand, whether summer or winter, with the previously forecasted peak demand. According to the Public Staff, a review of DEP's actual and weather adjusted peak load forecasting accuracy for one year shows that the forecasts in DEP's 2015 IRP underestimated the actual 2016 summer peak load by 1% and underestimated the actual 2016 winter peak load by 1%. However, a similar review of DEP's five-year peak load forecasting accuracy, based on the forecasts (2010-16) filed in its 2009 IRP, indicates a forecast error of 6%, resulting in an average annual overestimation of 766 MW. The Public Staff goes on to state that in regard to DEP's energy sales forecast, the 2009 forecast also reflects a 6% overestimation error.

The Public Staff commented that it believes the economic, weather-related, and demographic assumptions underlying DEP's peak and energy forecasts are reasonable and that DEP employed accepted statistical and econometric forecasting practices. Accordingly, the Public Staff found that DEP's peak load and energy sales forecasts are reasonable for planning purposes.

Public Staff Comments - DEC's Peak and Energy Forecasts

The Public Staff commented that similar to DEP, DEC no longer considers its summer peak to be its system peak. DEC's forecasted summer peak loads reflect a lower CAGR of 1.1% as compared to the 1.3% CAGR of the winter peaks that include load reductions associated with projected EE programs and prior to the activation of any DSM programs. On average for the next 15 years, the summer peaks are projected to be approximately 67 MW lower than the forecasted winter peaks. According to the Public Staff, it is evident that DEC has reduced its forecasts of electricity demand when the current projections are compared with the 2014 projected growth of 1.4% and the 2012 projected growth of 1.7%. DEC predicts that in the next 15 years, its summer season DSM programs will reduce load by 6% and its EE programs will reduce its summer peak demands by another 3% by 2031.

DEC's 15-year forecast predicts that its winter peaks will grow at a CAGR of 1.3%, as compared to the 1.5% forecast in its 2014 IRP and 1.7% growth rate projected in its 2012 IRP. Without the reduction in peak demand resulting from the implementation of its EE programs, DEC expects its winter peaks to grow at an average rate of 1.4% each year for the next 15 years. The average annual growth of its winter peak, which DEC considers its system peak, is forecasted to be 258 MW for the next 15 years. DEC predicts that over the planning horizon, the load reductions from its cumulative new EE programs will reduce its annual winter peak load by approximately 2%, as opposed to the 3% reduction projected from EE programs for its summer peak. The plan also assumes that DEC can reduce 3% of its load by 2031 by using its winter season DSM resources. While DSM is considered a capacity resource, it is projected to contribute significantly less in capacity savings in the winter as opposed to the 7% reduction in load projected during its summer peaks.

The Public Staff commented that DEC's energy sales, including the effects of its EE programs, are expected to grow at a CAGR of 1.0%. This growth rate is the same as predicted in 2014, but is considerably lower than the 1.7% predicted in its 2012 IRP.

The Public Staff's review of DEC's actual and weather adjusted peak load forecasting accuracy for one year shows that the forecasts in its 2015 IRP over-predicted its 2016 summer peak load by 4% and over-predicted its 2016 winter peak load by 5%. However, the one-year forecast errors are reduced to 3% for the winter peak and 2% for the summer peak on a weather-adjusted basis. In addition, the Public Staff reviewed DEC's peak load forecasting accuracy based on the forecasts for 2010-16 filed in DEC's 2009 IRP. The review indicates a forecast error of 4%, resulting in an average annual overestimation of 629 MW of demand. DEC's 2009 energy sales forecast reflects a 2% overestimation error.

The Public Staff commented that it believes the economic, weather-related, and demographic assumptions underlying DEC's 2016 peak and energy forecasts are reasonable and that DEC has employed accepted statistical and econometric forecasting practices. Accordingly, the Public Staff finds DEC's peak load and energy sales forecasts to be reasonable for planning purposes.

Public Staff Comments - DNCP's Peak and Energy Forecasts

The Public Staff commented that DNCP's 15-year forecast predicts that its adjusted summer peaks will grow at a CAGR of 1.5%. DNCP's 2014 and 2012 IRPs predicted a CAGR of 1.3% and 1.5%, respectively. The average annual growth of its summer peak is forecasted to be 293 MW for the next 15 years. DNCP predicts that in the next 15 years, the load reductions from its EE programs will reduce its annual peak load by approximately 1%, a decrease from the 2% forecast in its 2014 IRP. DNCP predicts that load reductions from the activation of its DSM programs will reduce its peak load by approximately 1% by 2031. DNCP's forecast of its winter peak loads reflects a slightly lower CAGR of 1.3% relative to the CAGR of 1.5% for its summer peaks. On average, the winter peaks are approximately 2,728 MW less than the forecasted summer peaks.

The Public Staff commented that DNCP's energy sales are predicted to grow at an average annual rate of 1.5%, an increase from the 1.1% in the 2014 IRP and a decrease from the 1.6% growth rate predicted in its 2012 IRP. According to the Public Staff, DNCP predicts that the savings from its EE programs will reduce its energy sales by approximately 1% by 2031, which is less than the 3% reduction in energy sales previously forecasted in its 2014 IRP.

The Public Staff's review of DNCP's actual peak load forecasting accuracy for one year shows that its 2015 IRP over-predicted DNCP's 2016 summer peak load by 1% and under-predicted its 2016 winter peak load by 9%. According to the Public Staff, DNCP's forecast errors are somewhat similar to the errors observed with DEP and DEC. The forecast errors are partially attributable to the mild summer and winter peak-day temperatures for 2016. The Public Staff also reviewed DNCP's peak load forecasting accuracy based on the forecasts for 2010 - 2016 in DNCP's 2009 IRP. The Public Staff commented that their review indicates a forecast error of 6%, an average annual overestimation of 1,035 MW of capacity. They go on to state that in regard to DNCP's energy sales, the forecast provided in the 2009 IRP reflects a 6% overestimation error.

The Public Staff commented that it believes the economic, weather-related, and demographic assumptions underlying DNCP's peak and energy forecasts are reasonable and that DNCP has employed accepted statistical and econometric forecasting practices. Accordingly, the Public Staff concludes that DNCP's peak load and energy sales forecasts are reasonable for planning purposes.

Public Staff Conclusions - Peak and Energy Forecasts

The Public Staff commented that the importance of load forecast accuracy cannot be overstated given that the purpose of the IRP is to determine the most reasonable plan to serve the forecasted load at least cost. The Public Staff notes that these are the first IRPs where DEP and DEC project that they will be winter peaking. In the event that DEC's estimated winter peak loads and temperatures are overstated and their summer peaks remain dominant, the lower growth in peak demands combined with the predicted increase in solar generation eliminates or significantly reduces the need for 435 MW of combustion turbine (CT) capacity planned for 2025 in DEC's IRP.

The Public Staff expressed a concern revolving around the unexpectedly large increases in the demand for electricity for all three IOUs at the time of the 2014 and 2015 system peaks in January and February during periods of abnormally low temperatures. The Public Staff notes that the influence of these two extreme winters has the potential to bias the estimation incorporated in regression analysis, thereby producing less accurate forecasts. The Public Staff goes on to state that identifying and properly forecasting the shape of customers' responses to abnormally cold conditions can be challenging due to its non-linear nature and may not be fully captured in the current equations in the IOUs' peak forecast models. As such, the Public Staff recommended that the utilities continue to review their winter peak equations in order to better quantify the response of customers to low temperatures. The Public Staff also recommended that the IOUs continue to present CAGRs for both the summer and winter seasons.

Summary of Growth Rates

The following table summarizes the growth rates for the IOUs' system peak and energy sales forecasts in their IRP filings.

2017- 2031 Growth Rates
(After New EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
DEP	1.0%	1.2%	0.9%	172
DEC	1.1%	1.3%	1.0%	286
DNCP	1.5%	1.3%	1.5%	293

SACE, NRDC and the Sierra Club Comments - Peak and Energy Forecasts

SACE, NRDC and the Sierra Club retained James F. Wilson, an economist and independent consultant in the electric power and natural gas industries, to evaluate the peak load forecasts used in the 2016 IRPs. According to comments filed by SACE, NRDC and the Sierra Club, the load forecast is a major factor determining a utility's need for new resources to meet system energy and demand. Overstating load growth will result in excess capacity on the system, and excess costs borne by ratepayers. Mr. Wilson concluded in his report, Review and Evaluation of the Peak Load Forecasts for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans (Wilson Report)[1] that DEC's winter peak load forecast – which is critical due to the utility's new "winter peaking" paradigm – is high, and that there was not enough information to determine whether DEP's load forecast was reasonable.

Mr. Wilson concluded that the risk of very high loads, especially in winter, was substantially exaggerated in the reserve margin studies performed for DEC and DEP. He indicates the critical assumptions about the impact of extreme cold on load levels were chosen based on simple regressions over rather arbitrarily-chosen temperature ranges, despite the high sensitivity of the results to the chosen ranges. He goes on to state that this casual approach stands in contrast to the rigorous process and analysis that the load forecasters at PJM Interconnection, LLC, underwent to enhance their load forecasting methodology following the polar vortex experience. According to Mr. Wilson, the PJM load forecasters developed enhancements to more accurately represent the relationship between loads and extreme temperatures. PJM's enhanced methodology now employs additional "weather splines" in order to more accurately capture the relationships between load and temperature over different temperature ranges, including extreme hot and cold conditions. Among other things, Mr. Wilson suggested that for future IRP proceedings DEC and DEP should research the drivers of sharp winter load spikes under extreme cold conditions, and study the relationship between cold and load, to inform future reserve margin studies.

NCSEA Comments - Peak and Energy Forecasts

NCSEA commented that there are differing forecasts for DEP-West and DEP-East that are not accounted for in DEP's single IRP. According to NCSEA, DEP acknowledges the differing load forecasts in the two service territories, noting that "events in the East are not always coincident

[1] Comments of Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club, Attachment A (Docket No. E-100, Sub 147), dated February 17, 2017.

in the West…." NCSEA goes on to state that when the two service territories are analyzed in a single IRP, the resulting analysis shows that the combined service territories are already a winter peaking system, which masks the fact that DEP-East is not expected to become a winter peaking system until 2023.

Due to the extensive and drastic differences between DEP-West and DEP-East, NCSEA requested that the Commission direct DEP to provide separate analyses for its DEP-East and DEP-West service territories in future IRP filings.

NC WARN Comments - Peak and Energy Forecasts

NC WARN commented that "it remains apparent in its IRPs that Duke continues to exaggerate its growth of electricity sales…." NC WARN notes that Duke's peak and energy growth projections are about as high as they have been in the past several IRPs and comments that the growth estimates are unreasonably high. According to NC WARN, Duke admits per customer usage of electricity has been flat to negative, but baldly claims that increases in number of customers will cause the entirety of the growth in energy (See DEC IRP, p. 16). NC WARN commented that one of the most glaring deficiencies in the Duke IRPs filed in this docket is the continuing overestimation of population growth and its effect on electricity usage. NC WARN states that the Commission must closely scrutinize the validity of the analyses used by Duke to justify growth projections.

Duke Reply Comments - Peak and Energy Forecasts

Duke noted that the Public Staff concluded that both DEC and DEP's load forecasts and methodologies were reasonable for planning purposes. Duke commented that DEC's forecasting error rate in the 2008-2009 timeframe mostly resulted from the severe economic downturn that occurred in 2009 and which no one was able to reasonably foresee. According to Duke, DEC suffered more than DEP and most utilities in the 2009 recession due to its large loss of industrial load, particularly from textiles. In contrast, the DEC peak load forecast developed in 2010 projected a 2013 value that was only 131 megawatts different than the actual weather-adjusted value for the year 2013. Duke commented that its forecasting methodology is always evolving in an effort to further improve the process, as a result of best practices and otherwise.

In response to the Public Staff's recommendation that DEC and DEP continue to review their winter peak equations in order to better quantify the response of customers to low temperatures, Duke commented that DEC and DEP regularly review their peak forecasting methodologies to ensure adherence to the latest industry standards. Duke goes on to state that given the increasing importance of efficiency trends on energy usage, DEC and DEP incorporate Statistically Adjusted End-Use Models (SAE) in their peak forecasting process. According to Duke, SAE models attempt to incorporate the effects of energy efficiency trends into the forecast as well as other end-use changes. This approach also has the advantage of generating a forecast for each month rather than a simple seasonal forecast. Duke commented that in the spring 2016 forecast, the SAE methodology produced a lower summer peak forecast, but a slightly higher winter peak forecast, which matches recent trends.

Duke addressed in its reply comments the fact that SACE, NRDC and the Sierra Club were critical of Duke's load forecasts. As an initial matter, Duke commented that SACE, NRDC and the Sierra Club admitted in their response to DEC and DEP's Data Request 1-5 that, "Mr. Wilson has not prepared any utility electric peak load forecasts." Duke commented, however, that Mr. Wilson's determination of peak load growth rates draws upon recent PJM trends reducing peak growth rates downward without consideration of the differences that may exist between PJM and North and South Carolina. Duke concluded that a comparison of PJM forecast trends to all North and South Carolina forecast trends is of very limited value. Duke noted that while both DEC/DEP and PJM use Moody's Analytics for their economic projections, within the January 2017 PJM Load Forecast Report, Moody's highlights the weakness of the PJM territory compared to the stronger southern economy.[1] Duke further commented that using current Moody's projections, population growth rates in North and South Carolina are expected to grow 5 to 6 times as fast as PJM, and nearly twice the expected U.S. growth rate.

Duke notes that in paragraph 26 on page 13 of the Wilson Report, Mr. Wilson correctly points out that "the very high loads that have occurred on recent, extremely cold winter days occur for very few days and hours; loads in other hours and on other days are much lower. Peak load forecasts intended to represent median or mean values should be relatively unaffected by such rare events." According to Duke, actual peaks fluctuate greatly while the weather normal peaks are not influenced by the extremes, either to the upside or downside. According to Duke, this is illustrated in Mr. Wilson's figure, JFW-3.[2] Therefore, Duke contends that the DEC and DEP forecasts represent an appropriate median forecast.

In reply comments, Duke also addressed Mr. Wilson's suggested use of multiple cold weather splines based on similar analysis performed by PJM. Duke commented that after reviewing PJM's cold weather load forecast and spline development, Astrapé Consulting (Astrapé), and Duke only identified a single cold weather spline at temperatures less than 25 degrees which is almost identical to the method employed by Astrapé. According to Duke, this critique further demonstrates that Mr. Wilson does not understand the load modeling methods used by Astrapé, and thus his criticisms should be rejected.

In response to NCSEA's comments, Duke disagrees with NCSEA's recommendation that the Commission require DEP to complete separate analyses for the DEP-East and DEP-West service areas in future IRPs and updates. Duke commented that while generation units are important to support local energy, voltage and reliability needs, DEP also studies, plans, and adds generation to serve DEP's entire system needs. Duke noted that significant efforts are in place to address the needs of both the east and west portions of DEP's service territory. The Western Carolinas Modernization Plan is one of the efforts in place to address these needs. Duke asserted that there is no compelling reason to change the IRP process to a service-area specific basis, as NCSEA requests.

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[1] http://www.pjm.com/~/media/library/reports-notices/load-forecast/2017-load-forecast-report.ashx, at 17-18.

[2] Id. at 7.

DNCP Reply Comments - Peak and Energy Forecasts

DNCP commented that the Public Staff's analysis found Dominion's forecasts to be reasonable. However, in response to the Public Staff's review of peak load forecasting accuracy, DNCP explained that it contracts with Moody's Analytics to provide economic explanatory variables for use as input variables in its econometric load forecasting models. DNCP explained in its reply comments that Moody's has forecasted higher economic growth than what actually occurred in Virginia, the region primarily served by DNCP. According to DNCP, this lower than anticipated economic growth in Virginia has been a key reason why its forecasts have been higher than what has actually occurred. DNCP commented that DNCP reviews its load forecasting models and processes annually, and improves the process as appropriate. However, DNCP acknowledges that predicting customer demand during times of very low temperature conditions has historically been a challenge.

Commission Conclusions - Peak and Energy Forecasts

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that the IOU's peak load and energy sales forecasts are reasonable for planning purposes. In reaching this conclusion, however, the Commission shares the concerns expressed by the Public Staff on issues related to statistical and econometric forecasting practices and by SACE that DEC's load forecast may be higher than reasonably justified. Therefore, as discussed in detail below, the Commission directs DEC to address this matter in its 2017 IRP update. Based on the fact that Duke studies, plans, and adds generation to serve DEP's entire system needs, the Commission is not persuaded by NCSEA's argument that DEP should alter its IRP planning to incorporate separate analyses for DEP-East and DEP-West.

The Public Staff commented that the economic, weather-related, and demographic assumptions underlying the utilities' peak and energy forecasts are reasonable and employed accepted statistical and econometric forecasting practices. The Commission finds no compelling evidence to the contrary. However, the Commission is aware of the challenges the utilities face to effectively forecast peak loads and appropriately incorporate recent extreme weather events. In particular, the Commission takes note of the Public Staff's comments that the 2014/2015 extreme winters have the potential to bias the estimation incorporated in regression analysis, thereby producing less accurate forecasts. The Public Staff goes on to state that identifying and properly forecasting the shape of customers' responses to abnormally cold conditions can be challenging due to its non-linear nature and may not be fully captured in the current equations in the IOU's peak forecast models.

The Commission further concludes that the DEC load forecast may be high. In reaching this conclusion, the Commission recognizes the Wilson Report. To quote from Mr. Wilson's report, "Overall, the DEC winter peak forecast seems somewhat high compared to the trend in the weather-adjusted peaks...." Mr. Wilson notes in his report on page 9 that for DEC, there has been a steady differential between the weather-adjusted summer and winter peaks during recent years, averaging 750 MW over 2009 to 2016, and averaging 683 MW over 2014 to 2016. The report states that DEC's current forecast breaks from this pattern, again suggesting that the winter peak forecast is high (see Figure JFW-6: DEC Summer and Winter Peaks, Historical and Forecast).

Continuing to address the DEC winter forecast, Mr. Wilson states in his report on page 7 that changes in end-use technologies may be affecting these brief, extreme winter peak loads under extreme cold conditions. The report points out that DEC stated it has not performed any formal analysis to determine which end uses are contributing to these load spikes on extremely cold winter mornings (response to Data Request SACE 2-11).

The Commission recognizes that it is important for each of the utilities to effectively address load response to temperature changes and especially extreme weather events when preparing peak load forecasts. Therefore, the Commission encourages the utilities to seek out and apply lessons learned to their forecasting methodologies wherever those best practices are identified.

Specifically, the Commission determines that DEC should address in its 2017 IRP Update, any refinements it makes to its forecasting methodology to better address load response in general, but especially the previous extreme winter weather events. In addition, DEC should clarify in its 2017 IRP Update how the 540 MW NCEMC backstand agreement is treated in its forecast.

RESERVE MARGINS

Public Staff Comments - Reserve Margins

The Public Staff noted in its comments that DEP, DEC, and PJM[1] use a recommended system reserve margin based on the Loss of Load Expectation (LOLE) probabilistic assessment. The LOLE is a metric that targets the probability of the loss of load on one day in a ten-year period, or one firm load shed event resulting in unserved energy for a firm customer on one day in a ten-year period. The reserve margins that correlate with this LOLE are approximately 17.0% for DEP and DEC, up from 14.5% in the 2014 IRP, and 16.5% for PJM. DEP and DEC's shift from being summer peaking systems to a winter peaking systems means that their reserve margins are designed to meet the winter peak.

PJM's 2015 Reserve Requirement Study recommends use of a reserve margin of 16.5% to satisfy the reliability criteria required by the North American Electric Reliability Corporation (NERC), Reliability First Corporation, and PJM's Planned Reserve Sharing Group. DNCP utilizes a coincidence factor to account for the historically different peak periods between DNCP and PJM, and, therefore, its ability to meet its PJM reserve requirements. This coincidence factor reduces DNCP's reserve margin requirement to 12.46%.

[1] DNCP utilizes the PJM capacity planning process for long- and short-term planning of capacity needs.

The Public Staff stated in its comments that for the planning period 2017 to 2031, the range of reserve margins reported by the electric utilities continues to be similar to those used in previous IRPs when adjusting for the lower than estimated load growth. For the period covered by the IOUs' 2016 IRPs, planned reserves are:

Electric Utility	Planned Reserve 2017-2031	Target Reserve Margin
DEP	17.0% to 27.0%	17.0%
DEC	17.0% to 24.0%	17.0%
DNCP	12.46% to 23.0%	12.46%

In their 2014 IRPs, DEP and DEC's target reserve margins were 14.5% and DNCP's was 11.2%. The increase in reserve margins is based on recent modeling results that demonstrated the volatility of loads during the winter months, generation resource availability, and overall electric generation and grid system response. DEP and DEC used Astrapé, to perform their reserve margin studies. The Public Staff commented that Astrapé has an extensive background in performing modeling and analysis for multiple utilities and regional transmission organizations (RTOs), including PJM. It also performed the modeling and analysis for DEP and DEC's reserve margin studies in 2012.

The Public Staff commented that DEP and DEC's operating reserves during the winter peaks in 2014 and 2015 fell below 1%, largely driven by extreme cold weather events in those years. The reduced operating margins were caused by a number of factors. The extreme cold resulted in unexpectedly high demand, in part due to additional use of resistive heaters such as electric strip heating and portable electric heaters. Increased load, however, was not the only factor that led to the reduced operating margins in 2014 and 2015. A number of plants in the system experienced forced outages because of the extreme cold due to controls and other essential systems being frozen or inoperable at those temperatures. Since that time, DEP and DEC have made capital and operational investments in freeze protection. According to the Public Staff, their systems should now be more resilient to cold weather and, therefore, less likely to experience such narrow operating margins. The Public Staff commented, however, that responses to its data requests indicate that the forced outage rates Astrapé assumed for the reserve margin study were not adjusted to reflect this additional freeze protection, potentially overestimating the likelihood of outages at winter peak and overestimating the recommended planning reserve margin percentage.

The Public Staff also expressed a concern that the approach used by Astrapé may overestimate the demand response associated with these low temperatures and thus the level of reserve margin needed.

The Public Staff addressed other concerns it has with methodologies employed in the Astrapé study. These additional concerns are documented on pages 46-50 in the Public Staff's comments. The Public Staff commented that it is not convinced that the recommended 17% reserve margin based on the winter peak is fully supported. The Public Staff recommends that the Commission direct DEP and DEC to continue to evaluate the methods and assumptions utilized in their 2016 reserve margin studies to try to better understand the relationships between extreme weather events and load response, as well as economic and load growth rates, and update this information as needed in their next IRPs.

Based on its review of the annual plans, the Public Staff commented that it believes that the reserves included in the utilities' IRPs are reasonable at this time for planning purposes. The Public Staff recommended that DEP and DEC continue to review their load forecasting methodology to ensure the assumptions and inputs remain current and that appropriate models quantifying customers' responses to weather, especially abnormally cold winter weather events, are employed.

The Public Staff also commented that to understand the impact of solar and other renewable generation on reserve margin adequacy, more precise modeling is needed. Analysis of the nature of solar power injected into the electrical system, or any other power source that is intermittent in nature, requires sub-hourly modeling with multiple and potentially complex scenarios. The Public Staff commented that sub-hourly modeling could necessitate more time and material intensive resources than currently used. The Public Staff recommends that IOUs in future IRPs evaluate the feasibility and benefits of advanced analytic techniques that incorporate sub-hourly modeling and more granular system performance data, and to the extent these advanced analytics are available at reasonable cost, utilize these resources to provide better information and understanding on optimizing reserve margin needs, as well as overall system operations.

SACE, NRDC, and the Sierra Club Comments - Reserve Margins

Based on conclusions in Mr. Wilson's Report entitled Review and Evaluation of the Reserve Margin Determinations for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans,[1] SACE, NRDC, and the Sierra Club commented that the reserve margins used in the 2016 IRPs were improperly inflated.

In his report, Mr. Wilson noted that the reserve margins used in the 2016 IRPs were based upon recommendations in the DEC and DEP 2016 reserve margin studies prepared by Astrapé and provided in response to data request SACE 1-8. Mr. Wilson's evaluation focused on three issues having to do with how loads were represented in the Astrapé studies and he concluded that these were inaccurate and unsupported.

First, according to Mr. Wilson, the reserve margin studies extrapolated the relationship between cold temperatures and winter loads that occurred in some hours in recent years over much lower temperatures that have not occurred for decades in a manner that greatly exaggerates the magnitude of the loads likely to occur under extreme cold conditions.

Second, Mr. Wilson notes that the economic load forecast uncertainty that was layered on top of the weather-related load distributions was also exaggerated, and is not supported by the underlying data it was based upon.

[1] Comments of Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club, Attachment B (Docket E-100, Sub 147) dated February 17, 2017.

Finally, Mr. Wilson notes that the reserve margin studies relied upon the DEC and DEP peak load forecasts, and treated them as forecasts of mean or average peak loads; however, at least in the case of DEC, the forecast value apparently was not a mean value, and was likely several hundred megawatts in excess of the mean forecast, which would bias the reserve margin by making it higher.

Mr. Wilson states that his review of these issues leads to the conclusion that the risk of very high loads, especially in winter, was substantially exaggerated in the reserve margin studies, and, therefore, the recommended increases in the DEC and DEP reserve margins are unsupported and should be rejected. Among other things, Mr. Wilson suggests that for future IRP proceedings, Duke should research the drivers of sharp winter load spikes under extreme cold conditions and study the relationship between cold and load to inform future reserve margin studies.

NC WARN Comments - Reserve Margins

NC WARN summarized the projected reserve margins over the planning period included in DEC and DEP's current IRP filings. NC WARN characterizes these reserve margins as "excessive" based in large part on a polar vortex in 2014. NC WARN goes on to state that witness Powers concluded at the certificate hearing for the NTE merchant plant in Docket No. EMP-92, Sub 0 that it is important to underscore that there is no reason to build any baseload capacity to meet once-in-a-generation polar vortex conditions that cause higher than expected winter peak loads.

NC WARN also noted in its comments that the most recent NERC report[1] on reliability factors and resource adequacy of utility regions around the country describes the anticipated reserve margin and recommends 15% as the reference margin.

Duke Reply Comments - Reserve Margins

Duke commented that it has appropriately addressed the Public Staff's concerns regarding the reserve margin studies, and Duke continues to fully support the findings recommending minimum 17% winter reserve margin targets for DEC and DEP.

Duke acknowledged in its reply comments that DEC and DEP have experienced significantly higher loads than projected during recent cold weather events. For example, Duke commented that DEP carried 21% summer planning reserve margins into 2015, but experienced real time operating reserves of -3% during the February 20, 2015 cold weather event. The significant load response to cold weather that DEC and DEP experienced in 2014 and 2015, along with the high penetration of solar resources on the Duke system and in the interconnection queues, were the primary drivers for conducting the new reserve margin studies in 2016.

Duke noted the following in its reply comments:

[1] North American Electric Reliability Corporation, 2016 Long-Term Reliability Assessment, December 2016.

The Public Staff expressed concerns that the regression equation modeling conducted in the reserve margin studies "may overstate the demand response associated with these low temperatures and thus the level of reserve margin needed." Specifically, Duke addresses the comments of the Public Staff that "This equation represents the peak daily load associated with the lowest temperature recorded that day, not necessarily occurring at the same hour. Astrapé appears to be using this peak day equation to determine hourly load for each hour of historic temperature data below 25 degrees. For example, if a day has 24 hours of temperature below 25 degrees, then this equation represents the load response at each of these hours regardless of the time of day." Duke commented that the Public Staff's assertion is not correct.

Duke replied that as discussed in its responses to Public Staff data request DEP 1-7 and DEC 17-7, the regression equations were based on peak hours on weekdays during the 2014 and 2015 time period. Duke noted that the actual filters placed on the data were reported in that data response. To correct the cold weather days in the synthetic load shapes, Duke commented that only the peak load hour of the day was modified using the regression equation and that the rest of the day was scaled up or down based on a standard cold weather day shape.

In order to ensure that demand response in the synthetic loads during cold temperatures was in line with the 2014 and 2015 actual peaks, Duke noted that Astrapé compared the weekday synthetic loads with the actual history. This comparison was provided in response to DEC-DEP SACE Data Request 1-11. According to Duke, the comparison demonstrates that the predicted loads calibrate well with the actual load response seen in 2014 and 2015.

Duke also addressed the Public Staff's comments that responses to its data requests indicate the forced outage rates Astrapé assumed for the reserve margin study were not adjusted to reflect operational investments in freeze protection, potentially overestimating the likelihood of outages at winter peak and overestimating the recommended planning reserve margin percentage. Duke noted that it explained the details of the cold weather outage modeling and related impacts on reserve margin study results in response to various Public Staff data requests. According to Duke, the outage data used in the 2016 reserve margin study was based on NERC Generating Availability Data System (GADS) data for years 2010-2014. As noted by the Public Staff, the outage assumptions were not adjusted to reflect the additional subsequent freeze protection investments in Duke's generating plants. Duke pointed out, however, that it is important to understand that the reserve margin studies captured the impact of unit outages through "random" Monte Carlo simulations, and although the outage draws are based on historic seasonal data, the outage draws are independent of temperature in the simulations.[1]

Further, Duke commented that the inclusion or exclusion of a couple of randomly occurring, short-term duration unit outages will not have a significant impact on the system equivalent forced outage rate (EFOR) values. Thus, the few hours that freezing problems may have occurred would typically have little impact on individual unit EFOR values or the reserve margin study results. Duke notes, however, that if unit outages were "forced" to occur on extreme cold

[1] Unit outage modeling is described more fully in Section III.F of the reserve margin study.

days within the simulations similar to 2014 and 2015, then it would put upward pressure on the reserve margin. Duke commented that the key is whether or not the outages are "forced" to occur concurrent with high winter peak loads. According to Duke, this is precisely what Astrapé modeled as a cold weather sensitivity. Astrapé forced additional units offline concurrent with cold temperatures and high loads similar to what was experienced in 2014 and 2015.[1] Duke commented that the results of the sensitivity analysis showed a significant impact on loss of load expectation and resulted in an increase in the reserve margin target of greater than 2%. As such, Duke did not force these cold weather outages into the base case of the reserve margin study.

Duke noted that the analysis shows that these outages were extremely isolated and short in duration. Because the outages are modeled independently from weather in the base case, removing the cold weather related outages has little to no impact on the overall reserve margin study results as reflected by the slight change in EFOR. Duke commented that if the cold weather outages were forced to occur at the same time as extreme cold weather and high load events, as reflected in the cold weather outage sensitivity, then the results change dramatically. According to Duke, based on the lessons learned in 2014 and 2015, Astrapé and Duke did not believe it prudent to force these outages to occur during the extreme cold temperatures in the base case analysis and thus only modeled the average EFOR across the winter.

Finally, Duke commented on the Public Staff's recommendation that utilities evaluate the feasibility and benefits of advanced analytic techniques that incorporate sub-hourly modeling and more granular performance data in order to better analyze the nature of solar power injected into the electrical system, or any other intermittent power source. Duke noted that the Duke IRP team is in the process of evaluating available model enhancements. Duke commented that the IRP utilizes hourly long-term models for system optimization and production cost modeling. The computational time to produce results in these models has generally not allowed these longer-term models to be developed at a sub-hourly granularity. According to Duke, sub-hourly analysis is more appropriately handled in shorter term production costing models utilized by the systems optimization group. As this group makes advancements in studying operational impacts, such as incremental ancillary service requirements, results will be shared with the IRP team as inputs to the IRP models.

DNCP Reply Comments - Reserve Margins

DNCP commented that it is already working to meet the Public Staff's recommendations relative to advanced analytic techniques that incorporate sub-hourly modeling and more granular system performance data. DNCP noted that in order to accommodate the anticipated growth of intermittent renewable generation, Dominion is in the process of integrating generation, transmission, and distribution planning more fully, and investigating more granularity in the modeling. According to DNCP, it anticipates that this effort will help ensure reliable system operations as the resource mix evolves in the future, especially concerning the addition of intermittent generation. DNCP commented that it intends to include the results of this work in future IRPs.

[1] The cold weather sensitivity can be found in Section VI of the reserve margin study with the underlying forced outage penalty found in the Confidential Appendix.

Commission Conclusions - Reserve Margins

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that the reserve margins included in the utilities' IRPs are reasonable at this time for planning purposes. However, the Commission finds the analyses by the Public Staff and SACE's report by Mr. Wilson to be helpful regarding the question of whether DEC and DEP should move to a 17% winter reserve margin target. The Commission concludes that this move is not supported by the evidence in this proceeding. Nevertheless, the concerns outlined by the Public Staff, as well those discussed in Mr. Wilson's report, should be acknowledged by DEC and DEP and fully addressed in their 2017 IRP updates.

Further, the Commission is not persuaded by NC WARN's arguments relying on witness Power's testimony in Docket No. EMP-92, Sub 0. In the Order issued January, 19, 2017, in that docket, the Commission observed the following:

> On cross-examination, however, witness Powers acknowledged he undertook no independent modeling, no independent analysis of key economic factors, such as income, electricity prices, and industrial production indices, and no independent analysis or modeling of weather projections. He only looked at the last ten years of actual loads reported by DEC and DEP. He also testified on cross-examination that he did not consider population growth to be necessarily connected to load growth and that he made no assumptions about manufacturing output in North Carolina over the next 20 years.

Order Granting Certificate with Conditions, at p. 14 (January 19, 2017).

NC WARN noted in its comments that the most recent NERC report on reliability factors and resource adequacy of utility regions around the country describes the anticipated reserve margin and recommends 15% as the reference margin. Based on a review of the NERC report, the Commission acknowledges that NERC uses 15% as the "Reference Margin Level" for the SERC-E region. However, the Commission does not view NERC's Reference Margin Level as a recommendation for use as a reserve margin. The NERC definition of Reference Margin Level provided in the report, at page 171, is as follows:

> The assumptions of this metric vary by assessment area. Generally, the Reference Margin Level is typically based on load, generation, and transmission characteristics for each assessment area and, in some cases, the Reference Margin Level is a requirement implemented by the respective state(s), provincial authorities, ISO/RTO, or other regulatory bodies. If such a requirement exists, the respective assessment area generally adopts this requirement as the Reference Margin Level. In some cases, the Reference Margin Level will fluctuate over the duration of the assessment period, or may be different for the summer and winter seasons. If one is not provided by a given assessment area, NERC applies a 15% Reference Margin Level for predominantly thermal systems and 10% for predominantly hydro systems.

The analyses regarding reserve margin targets is extremely technical and complicated, made even more so by the advent of winter peaking on DEP and DEC's systems. The Commission relies heavily on the Public Staff's review and analysis to make its decisions on this subject. Therefore, the Commission determines that DEC and DEP should work with the Public Staff to address the Public Staff's and Mr. Wilson's reserve margin concerns and to implement changes as necessary to help ensure that the reserve margin target(s) are fully supported in future IRPs. Further, the Commission requests that Duke and the Public Staff file a joint report summarizing their review and conclusions within 150 days of the filing of Duke's 2017 IRP updates. In addition to addressing the reserve margin concerns identified by the Public Staff and Mr. Wilson, the report should clearly define the support and basis for the targeted reserve margins incorporated into the IRPs. If the parties cannot reach consensus, then the report should outline their differences and recommend a procedure for the Commission to pursue in reaching a conclusion about the reserve margins recommended by DEC and DEP in their IRPs.

In addition, the Commission concurs with the Public Staff's recommendation that in future IRPs the IOUs should evaluate the feasibility and benefits of advanced analytic techniques that incorporate sub-hourly modeling and more granular system performance data. Further, to the extent that these advanced analytics are available at reasonable cost, the IOUs should utilize these resources to provide better information and understanding on optimizing reserve margin needs, as well as overall system operations.

SYSTEM PEAKS AND USE OF DSM RESOURCES

Public Staff Comments - DEP's System Peaks and Use of DSM Resources

The Public Staff noted that DEP's 2016 annual system peak of 13,244 MW occurred on January 19, 2016, at the hour ending 7:00 a.m., at a system-wide average temperature of 21 degrees Fahrenheit (°F), which is above the normal peak day temperature of 17°F. DEP's all-time peak of 15,515 MW occurred on February 20, 2015, at a temperature of 12°F. Given the relatively mild peak-day winter temperature in 2016 and ample available reserves, DEP did not activate any of its DSM programs. This is in contrast to 2015, when a significant amount of generation was not available for dispatch on the morning of the winter peak. Due to the extreme temperatures, DEP activated its DSDR[1] program, reducing load by 290 MW; its commercial, industrial, and government (CIG) and EnergyWise demand response programs, reducing load by 26 MW; and its large load curtailment program, reducing load by 240 MW. The Public Staff commented, for that peak hour in 2015, DEP's operating margin fell to -1.6%. As a result, in order to prevent shedding of load DEP acquired 700 MW of non-firm energy, 500 MW from DEC and the remainder from PJM and others.

Based on the Public Staff's comments, DEP's summer system peak of 13,033 MW occurred on July 26, 2016, at the hour ending 4:00 p.m., at a system-wide temperature of 94°F, which is considered mild or slightly below average temperature. This peak was 211 MW less than the previous winter's peak, and ample available reserves led DEP to activate only 23 MW of its DSM resources.

[1] The Commission has classified DSDR as an EE program, but DEP generally uses it as it would a DSM program.

The Public Staff noted that during DEP's ten highest peak loads in 2016, DEP activated its DSM programs twice during the summer season (23 MW and 2 MW). In response to the Public Staff's data request, DEP indicated that none of the ten highest 2016 peak loads warranted the drastic response to actual load conditions observed during the winters of 2014 and 2015 and the summer of 2015. DEP indicated that in 2016, reserves were more than adequate, and system energy costs (lambdas) were not significantly greater than average. As it has stated in prior IRP comments, the Public Staff commented that it believes the utilities should maximize the use of their DSM to reduce fuel costs, especially when marginal costs of energy are high, as well as to ensure reliability.

Public Staff Comments - DEC's System Peaks and Use of DSM Resources

The Public Staff noted that DEC's 2016 annual system peak of 18,037 MW occurred on July 25, 2016, at the hour ending 5:00 p.m., at a system-wide temperature of 96°F. DEC's winter system peak of 17,136 MW occurred on January 19, 2016, at the hour ending 8:00 a.m., at a system-wide temperature of 16°F. According to the Public Staff, DEC did not activate any of its DSM resources during the winter system peak, but it did activate some DSM resources during the summer peak, for a reduction in summer peak demand of 456 MW. During its ten highest peak loads in 2016, DEC activated its DSM programs five times during the summer season. DEC did not activate any DSM resources during the winter season peaks. In response to a Public Staff data request, DEC indicated that none of the winter peak loads in 2016 warranted the use of DSM.

The Public Staff further commented that given the relatively mild peak-day temperatures during much of 2016, ample available reserves, and system energy costs (lambdas) were not significantly greater than average, and DEC did not activate its DSM programs as much as in 2015. By contrast, in 2015 DEC reduced load by 468 MW with its commercial and industrial DSM programs at its highest peak load on February 20, 2015. At that time, DEC's operating margin fell to 1.2% due to higher than expected load conditions and generation resource outages. According to the Public Staff, during the 2015 summer season, DEC did not operate its DSM at the time of its highest summer peak load; however, there were several other days during the summer that DEC activated its Power Manager Program and reduced load by several hundred MW.

Public Staff Comments - DNCP's System Peaks and Use of DSM Resources

The Public Staff noted that DNCP's 2016 annual system peak of 16,914 MW occurred on July 25, 2016 at the hour ending 4:00 p.m. with an average temperature of 97°F. DNCP activated its Non-Residential Distributed Generation (DG) Program and Air Conditioning (AC) Cycling Program to reduce load by 5.3 MW and 100 MW, respectively, during the summer peak. DNCP's winter peak of 16,173 MW occurred on January 19, 2016, at the hour ending 8:00 a.m., at a system-wide temperature of 17°F. According to the Public Staff, DNCP did not activate its DSM resources during the 2016 winter peak, but did activate its DG Program and AC Cycling Program during several of its highest ten summer and winter peak days.

Public Staff Conclusions - System Peaks and Use of DSM Resources

The Public Staff acknowledges that load conditions, energy prices, generation resource availability, and customer tolerance for the use of DSM are all important considerations in determining which DSM resources should be deployed. Use of DSM resources is largely dependent on the circumstances and cannot be prescribed in any definitive manner. As previously noted, 2016 was a relatively mild year for temperatures, with lower loads and marginal costs of generation as compared to February 2015. Nevertheless, the Public Staff concluded that the utilities should maximize the use of their DSM to reduce fuel costs, especially when marginal costs of energy are high.

In its review of the DSM activations at the time of the 15 highest hourly peaks for each utility, the Public Staff notes an ongoing concern regarding the amount of DSM load reduction actually realized during a DSM event, versus the amount of DSM resource available for an event, as represented in the load forecast tables. The load forecast tables represent the total amount of DSM resource in the resource mix for each IOU. However, when the IOU activates the DSM resource, the IOU may only activate all or only a portion of the resource. The forecast tables do not indicate the response the IOU is likely to receive from customers when an activation takes place. According to the Public Staff, taking into account the expected response from customers when forecasting the availability of the DSM resource would provide a more accurate forecast.

A second area of concern for the Public Staff involved the difference in DSM resources available in the winter and the summer due to winter season DSM typically not being cost effective. The Public Staff commented that each North Carolina utility has a summer air conditioning load control program, customer-owned standby generation, and load curtailment programs. Standby generation and load curtailment resources are available to each utility in the winter season. The Public Staff commented, however, that DEP is the only utility that has any dispatchable DSM for use during the winter season (the Heat Strips and Water Heater measures in the EnergyWise program). They also noted that DSDR was also used by DEP several times in both the winter and summer seasons to reduce peak demand.

The Public Staff offered two recommendations to address their concerns regarding DSM. First, the DSM resources forecast to be available in the IRP should represent the reasonably expected load reductions that are available at the time the resource is called upon as capacity. Through evaluation, measurement, and verification (EM&V) of these DSM programs, utilities should identify the enrolled DSM capacity and the reasonably expected level of load reduction that can be reliably called on during a DSM event, winter and summer. To accomplish this, the Public Staff recommended that each IOU begin including in its discussion of the activations of DSM and curtailable resources the percentage of DSM or curtailable resources called upon (in terms of MW), and the load reduction response (MW reduced) for each event for each program. Second, the Public Staff recommended that each IOU investigate and implement any cost-effective DSM that would be available to respond to winter peak demands.

Duke Reply Comments - System Peaks and Use of DSM Resources

Duke replied to the Public Staff's conclusion that the utilities should maximize the use of their DSM to reduce fuel costs, especially when marginal costs of energy are high. Duke commented that this is a practice currently utilized by DEC and DEP. However, the program cost impact and lost capacity value associated with customer attrition are also taken into account. According to Duke, this ensures that each program activation provides a net positive benefit to customers.

Commission Conclusions - System Peaks and Use of DSM Resources

The Commission emphasizes that utilizing evaluation, measurement, and verification to help ensure that the impact of DSM programs is accurately represented in the IRPs. The Commission recognizes that the amount of DSM load reduction actually realized during a DSM event may be different than the totals included in IRP planning and included in the load forecast tables. However, the Commission is of the opinion that the planned reserve margin targets, in part, exist to address the difference in actual DSM achieved versus planned, in much the same way it covers generating capacity that is not available at the time of the peak. Therefore, the Commission does not find it necessary at this time to act on the recommendation of the Public Staff to instruct the IOUs to discuss DSM activations in terms of the percentage of DSM called upon versus actual response. In addition, the Commission acknowledges Duke's reply comments that state DEC and DEP have incorporated the percentage of DSM (or curtailable resources) in terms of capacity load reduction response (MW reduced) for each program into their DSM activation reporting process. Duke commented that this information will be included in future IRPs.

However, the Commission does share the concern expressed by the Public Staff about the difference in DSM resources available in the winter compared to the summer, especially given the increased sensitivity in planning for winter loads and resources. The Commission agrees with the Public Staff that additional emphasis should be placed on defining and implementing cost-effective DSM programs that will be available to respond to winter peak demands.

ENERGY EFFICIENCY (EE) FORECASTS AND PROGRAMS

Public Staff Comments - EE Forecasts and Programs

The Public Staff's review of the IOUs' DSM/EE forecasts and programs indicated that each IOU complied with the requirements of Commission Rule R8-60 and previous Commission orders[1] regarding the forecasting of DSM and EE program savings, as well as the presentation of data related to those savings. Each IOU included information about its respective DSM and EE portfolios that is largely the same as reported in the 2015 IRP updates. Each IOU appropriately addressed the changes in their respective forecast of DSM and EE resources and the peak demand and energy savings from those programs.

The Public Staff commented that several factors continue to affect the IOU's ability to develop and implement cost-effective EE programs. Technological changes are providing more efficient lighting measures for consumers. Additionally, there are potential changes to federal standards for future lighting measures that could make it difficult for an IOU-sponsored EE lighting program to be cost-effective. According to the Public Staff, changes in the avoided costs also are likely to make it more difficult to attain cost-effective programs in general. Further, the Public Staff opined that with lighting being a large portion of the EE portfolios, it is not likely that the amounts of EE savings from lighting measures will continue beyond one or two

[1] Ordering paragraphs 8 and 9 of Order Approving 2011 Annual Updates to 2010 Biennial Integrated Resource Plans and 2011 REPS Compliance Plans, dated May 30, 2012, in Docket No. E-100 Sub 128, and ordering paragraphs 7 and 8 of Order Approving Integrated Resource Plans and REPS Compliance Plans, dated June 26, 2015, in Docket No. E-100, Sub 141.

more years. Other technologies such as space heating/cooling and building envelop measures will continue to face similar headwinds as technologies improve, standards rise, and avoided costs decrease.

Public Staff Comments - DEP and DEC's EE Forecasts and Programs

The Public Staff commented that DEP and DEC's portfolios of EE programs are not materially different from those in the 2015 IRP updates. DEC and DEP have continued to merge their programs so that they mirror one another and have the same incentive structures, incentive amounts, and eligibility requirements. The Public Staff noted that the Commission has approved several requests to modify existing EE programs and to approve new programs, making DEP and DEC's programs virtually identical. The Public Staff commented that in the last few DSM/EE rider proceedings, both DEC and DEP's portfolios have been shifting the source of EE savings away from lighting measures toward behavioral programs (My Home Energy Report and Business Energy Report).

The Public Staff noted that DEP and DEC continue to rely on their 2012 market potential studies for input into EE program design and development. DEP and DEC are currently working to update their market potential study and expect to file their updated studies with their 2017 IRP updates.

The Public Staff noted that DEP and DEC provided a comparison of projected EE savings from their 2014 and 2016 IRPs. According to the Public Staff, DEC's projections did not vary more than 10% between 2014 and 2016; however, DEP's projections did. DEP attributes most of this variance to the addition of several new EE programs to its portfolio over the last two years. The Public Staff also compared the changes between the 2015 IRP update and the 2016 IRPs, and found similar results (11% decrease for DEP and a 9% decrease for DEC, when excluding historical and "rolled off" EE savings). The Public Staff concluded, however, that this comparison may not be appropriate in light of the changes in how the data are presented in the respective IRPs.

Prior to the 2015 IRP updates, the Public Staff compared the net EE savings from one year to another over each planning horizon. According to the Public Staff, this generalized view was sufficient to understand the changes made to EE between IRPs. However, in the 2015 IRP updates, DEP and DEC began removing savings that would "roll off" the EE portfolio. This roll off was a function of measures that had reached their measure life. The Public Staff commented that the rolled-off amount of savings is not easily calculated for years prior to 2015. Therefore, a comparison of data to understand the changes to the EE portfolio savings is not available with any degree of integrity.

The Public Staff noted that both DEP and DEC gave further explanation of this process in their responses to Public Staff data requests. Table C-3 in both DEC and DEP's IRPs explain the process used to move EE savings from the EE portfolio to the forecasted energy sales.[1] The Public

[1] The process begins by determining the EE savings from all measures on a cumulative basis (measures installed prior to the current year and new measures installed in the current year.) Once cumulative EE savings are determined, the Companies then determine the savings that have reached the end of their measure life. Those expiring savings are then removed from the cumulative amount ("rolled-off"). The net impact on EE savings (savings from new measures

Staff commented that it believes this process is reasonable and more accurately conveys the impact of EE on the load forecast of the IRP. These rolled-off EE savings eventually become part of the forecasted energy sales. According to the Public Staff, it is reasonable to expect these rolled-off or historical EE savings will continue to be embedded in the load forecast, as customers are unlikely to revert to less energy efficient habits after an EE measure expires. Further, it is reasonable to expect that consumers would continue to observe efficient habits and replace expiring measures with an equally, or more efficient measure. With changes in energy consuming behaviors, technologies, or appliance standards that will occur in the future, the Public Staff believes that EE measures reaching the end of their measure life and their savings should not be counted as EE portfolio savings. In other words, EE savings do not continue in perpetuity.[1] However, as noted by the Public Staff, the impact of those ongoing behaviors will be determined through future appliance saturation studies and other load research studies that will be captured and represented in DEP and DEC's load forecasts.

Public Staff Comments - DNCP's EE Forecasts and Programs

The Public Staff noted that DNCP's portfolio of EE programs is not significantly different from those in previous IRPs. Two new programs were recently approved (Small Business Improvement and Residential LED Retail Lighting programs) and included in the portfolio. DNCP also included the Residential Programmable Thermostat program in its projections of future EE savings. However, the Public Staff commented that this program was rejected by the Virginia State Corporation Commission (VSCC).[2] Given the small impacts included in the IRP from the Residential Programmable Thermostat program on DNCP's EE portfolio, the Public Staff did not recommend an adjustment to the projected DSM/EE savings.

According to the Public Staff, the projected savings from DNCP's portfolio of EE and DSM programs are substantially less (more than 10% from the savings in the 2015 IRP update) than previous IRPs. There is an overall decrease in peak demand savings of 46% and in energy savings of 75% from the 2015 IRP update. The Public Staff commented that the primary reason relates to the removal of DNCP's Voltage Conservation program from its portfolio. DNCP indicates that this program is directly related to its deployment of automated meter infrastructure (AMI) across its system, and until it has made a more firm decision on AMI deployment, DNCP chose to remove the Voltage Conservation program from its DSM/EE portfolio. The Public Staff also noted that over the planning period, DNCP's EE savings projections indicate a significant

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installed in the current year, and savings expiring at the end of their measure life) are then subtracted from each company's load forecast.

[1] The Commission has recently ruled that for purposes of REPS compliance, once the utility EE measures reach the end of their measure life, they are not expected to produce continued EE savings in perpetuity that would be eligible for REPS compliance. See Order Approving REPS and REPS EMF Rider and REPS Compliance Report, at 26-27, Docket No. E-2, Sub 1109 (January 17, 2017).

[2] Final Order dated April 19, 2016, in Case No. PUE-2015-00089.

shift away from EE savings associated with lighting measures to savings more associated with space heating/cooling.

The Public Staff noted that DNCP completed a market potential study in early 2015; however, DNCP did not incorporate the impacts related to the study until the 2016 IRP. According to the Public Staff, many of the programs discussed in the market potential study are already incorporated in some form in an approved EE program in DNCP's portfolio. The Public Staff commented that in response to its data request, DNCP indicated that it used the potential study as a "guidance tool" in designing future EE programs. Measures could be incorporated into the IRP based on market trends, but there is no direct link between the potential study and the IRP. DNCP also noted that the potential study serves as a first assessment of measures that may be integrated into the EE portfolio, but further review of the measure, as well as information from potential vendors, is used to develop a cost-benefit model. Only after these steps, and a determination that a program could be cost-effectively designed and implemented, would DNCP begin to incorporate the EE measure into its IRP.

The Public Staff further noted that the regulatory environment in Virginia is more stringent toward approving EE measures. The Public Staff commented that DNCP has indicated, in past DSM/EE rider proceedings, that it is more cost-beneficial to implement EE programs on a system-wide basis in Virginia and North Carolina. The Public Staff recommended that where DNCP and its Virginia affiliate cannot offer an EE program on a system-wide basis, DNCP should evaluate whether it could cost-effectively offer the program on a North Carolina-only basis. According to the Public Staff, this approach has allowed DNCP to include cost-effective programs in its North Carolina EE portfolio, the most recent being the Residential Retail LED (light emitting diode) Lighting Program.[1] The Public Staff noted that such a program is consistent with findings of the potential study, which included several LED measures. DNCP continues to evaluate a number of options that would allow it to incorporate more of the measures identified in the market potential study into the IRP.

Public Staff Conclusions - EE Forecasts and Programs

Based on the Public Staff's review of the projected DSM/EE savings and DSM/EE portfolios discussed in the IRPs of DEP, DEC, and DNCP, the Public Staff recommended that the IOUs continue to explain any change of 10% or more in the savings projections from the previous IRP or IRP update. Additionally, the Public Staff recommended that the IOUs identify any changes in EE-related technologies, regulatory standards, or other drivers that would impact future projections of EE savings regardless of the 10% threshold. For example, changes in lighting technologies and standards will impact the IOU's ability to achieve cost-effective savings from lighting measures. According to the Public Staff, those changes and trends should receive more detailed discussion in the IRPs. Additionally, the Public staff recommended that the IOUs continue to pursue all cost effective EE and DSM. Finally, the Public Staff recommended that DNCP evaluate the potential to cost-effectively implement any DSM/EE program on a North

[1] Approved December 20, 2016, in Docket No. E-22, Sub 539.

Carolina-only basis if approval has been denied in Virginia to implement the program on a system-wide basis.

SACE, NRDC, and the Sierra Club Comments - EE Forecasts and Programs

SACE, NRDC, and the Sierra Club commented that the Duke IRPs underutilize cost-effective energy efficiency. These comments rely, in part, upon a study prepared by Daymark Energy Advisors (Daymark) entitled Duke Energy's Resource Plans for the Carolinas: An Evaluation and Alternative Approach, (February 17, 2017), included as Attachment D to the initial comments of SACE, NRDC, and the Sierra Club. Daymark found that Duke prematurely limited the amounts of energy efficiency available as a resource to DEP and DEC through an overly restrictive screening process. According to SACE, NRDC, and the Sierra Club, screening out efficiency options prior to running the resource planning models biases the analysis in favor of supply-side options. SACE, NRDC, and the Sierra Club further commented that Duke's planning process does not allow energy efficiency to be easily compared with supply-side resources in a capacity expansion model.

The Daymark Study states that the screening process by Duke limits the amount of energy efficiency programs to between 60% and 90% of the economic potential (determined by avoided cost). The Daymark Study references Duke's 2012 EE Market Potential Study and noted that it incorporated estimates for the generation supply cost savings that energy efficiency could provide, avoided cost. The Daymark Study stated that this avoided cost level in 2012 was determined to be \$0.07/kWh and Duke's screening process considered energy savings associated with levelized cost of energy that is lower than \$0.07/kWh of the DSM supply curve to be economical. Thus, "economic potential" is defined as the energy savings associated with EE incremental and program cost being less than \$0.07/kWh. The Daymark Study notes that DEC considered 60% of the economic potential to be achievable and included in Duke's Base preferred case. Duke's high EE case is approximately 1.5 times greater than the achievable level identified in the Base case.

The Daymark Study defines a new level of energy savings (i.e., strategic potential) to emphasize the possibility of additional EE savings to consider in the long-term planning. As noted in the Daymark Study, strategic potential is not a standard tem in the EE potential studies. However, according to the Daymark Study, use of the strategic potential in planning would not limit the amount of energy efficiency resource available by arbitrarily defining the limit of economic potential.

Duke Reply Comments - EE Forecasts and Programs

Duke commented that SACE/Daymark disagreed with DEC and DEP's estimate of economic and achievable EE potential, which was based on the most recent market potential study at the time of the IRP. Duke noted that the economic potential study employed by DEC and DEP is the cumulative savings up to a levelized cost (including program costs) of \$0.07/kWh, a value derived from the avoided costs in effect at the time of the Market Potential study. Duke commented that this is the most logical way to estimate an economic potential because, as required by the regulations in the Carolinas, an EE program must be cost effective in order to be offered, with the exception of certain programs designed for income-qualified customers.

According to Duke, the Daymark Study contends that all of the EE Potential up to approximately $0.09/kWh should be included in the IRP because the levelized costs for this EE Potential "is still lower than the cost of additional nuclear generation." Duke commented that SACE's choice of the portion of the DSM supply curve that they consider to be "inelastic" is purely arbitrary and not relevant. In addition, Duke commented that the proposed "strategic potential" approach does not make sense because the purpose of estimating economic potential in a Market Potential Study is to determine what EE programs would be economically viable in the traditional sense that programs can be deployed at a levelized cost that is lower than the equivalent avoided cost used to value energy efficiency.

Duke commented that it is extremely pertinent and important to point out that, at the time of its Market Potential study, the levelized cost that was considered as the cutoff point for the economic potential was set at $0.07/kWh based upon the avoided costs in effect at the time. However, Duke noted that since that time the levelized costs used in the avoided cost filings have declined by almost 50% versus the costs at the time of the Market Potential study. Because DEC and DEP continued to use an economic potential that was based on the significantly higher avoided costs at the time of the Market Potential study, the forecast of future EE potential included in the 2016 IRPs could actually be considered overly optimistic because it was based on an economic potential that is significantly higher than what would be calculated using this method today.

Finally, Duke commented that DEC's 2016 IRP analysis showed that the inclusion of a portfolio which contained more EE (High Case) was found to be more expensive than the Base Case, as shown in Table 8-B on page 37 of the 2016 DEC IRP. In addition, Duke stated that even if the High Case were chosen, the impact on the resource plan was minimal, resulting only in the delay of a CT by one year during the next 15-year planning horizon. Therefore, SACE's contention that Duke "prematurely limited" the amount of EE in its IRP analysis is simply without foundation. Duke commented that the IRP report clearly shows that Duke evaluated the inclusion of additional EE in the High EE case and the resulting portfolio was found to be more expensive than the recommended IRP resource plan.

DNCP Reply Comments - EE Forecasts and Programs

DNCP noted that the Public Staff recommended that the utilities continue to explain any change of 10% or more in the savings projections from the previous IRP or IRP update; and identify any changes in EE-related technologies, regulatory standards, or other drivers that would impact future projections of EE savings regardless of the 10% threshold. DNCP commented that it will continue to explain changes of 10% or more in the savings projections from the previous IRP or IRP update. Further, DNCP commented that it would be challenging to identify "all" changes in EE-related technologies, regulatory standards, or other drivers that would impact future projections of EE savings regardless of the 10% threshold. According to DNCP, it is more reasonable to be required to include "major known" changes in regulations and manufacturing standards, rather than each one regardless of any type of materiality standard.

DNCP also noted that the Public Staff recommended that where Dominion and its Virginia affiliate cannot offer an EE program on a system-wide basis that DNCP evaluate whether it could cost-effectively offer the program on a North Carolina-only basis. DNCP commented that

Dominion has previously offered North Carolina-only EE programs, such as its Residential Retail Lighting Program, and will continue to evaluate additional North Carolina-only programs, as may be appropriate.

Commission Conclusions - EE Forecasts and Programs

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that the IOU's approach to utilizing economic and achievable EE potential, linked to avoided cost calculations, is appropriate to ensure the cost-effectiveness of EE Programs. The Commission agrees with the Public Staff's comments that the utilities complied with the requirements of Commission Rule R8-60 and previous Commission orders[1] regarding the forecasting of DSM and EE program savings, as well as the presentation of data related to those savings. However, the Commission does not agree with the position of SACE, NRDC, and the Sierra Club that the Duke IRPs underutilize cost-effective energy efficiency. Further, the Commission is not persuaded by SACE, NRDC, and the Sierra Club's argument for using a "strategic potential" approach to planning, as defined in the Daymark Study.

The Commission appreciates the Public Staff's assessment that several factors continue to affect the IOU's ability to develop and implement cost-effective EE programs. As noted in its comments, changes in avoided costs, including those pending before the Commission in Docket No. E-100, Sub 148, could make it more difficult to attain cost-effective programs in general. Still, the Commission finds the logical approach of the utilities, linked to avoided costs, valid for planning.

The Commission acknowledges the challenges described in the Public Staff's comments, including the "headwinds" associated with technology improvements, rising standards, and decreasing avoided costs. The IOUs should continue to explain changes of 10% or more in the savings projections from the previous IRP or IRP update. The Commission also finds it reasonable for the IOUs to continue to address major known changes in EE-related technologies, regulatory standards, and other drivers that would impact future projections of EE savings.

Finally, the Commission encourages DNCP to continue to evaluate additional North Carolina-only programs.

CARBON REGULATION AND CLEAN POWER PLAN

Public Staff Comments - Carbon Regulation and Clean Power Plan

On June 18, 2014, the United States Environmental Protection Agency (EPA) proposed a new rule under Section 111(d) of the Clean Air Act (Clean Power Plan or Plan) to limit carbon dioxide (CO_2) emissions from existing fossil fuel-fired electric generating units by requiring substantial reductions in CO_2 intensity. On August 3, 2015, the EPA finalized the Clean Power

[1] See Ordering paragraphs 8 and 9 of Order Approving 2011 Annual Updates to 2010 Biennial Integrated Resource Plans and 2011 REPS Compliance Plans, dated May 30, 2012, in Docket No. E-100 Sub 128, and ordering paragraphs 7 and 8 of Order Approving Integrated Resource Plans and REPS Compliance Plans, dated June 26, 2015, in Docket No. E-100, Sub 141.

Plan, requiring states to submit to EPA by September 6, 2016, an initial state implementation plan designed to achieve the required CO_2 reductions, and a final plan by September 6, 2018. The Clean Power Plan established two rate-based and two mass-based compliance pathways for states to consider in the development of their state implementation plans. Under the Plan, the EPA should review and approve or disapprove state plans within 12 months of receipt. The emission limitations are scheduled to take effect beginning in 2022.

Petitions challenging the Clean Power Plan were filed with the U.S. Court of Appeals for the District of Columbia (D.C. Circuit). The U.S. Supreme Court issued a stay on implementation of the Clean Power Plan on February 9, 2016. The D.C. Circuit heard oral arguments on September 27, 2016. A decision from the DC Circuit is expected in 2017, and is likely to be appealed to the Supreme Court. Additional uncertainty as to how North Carolina and the EPA will proceed in regard to the Clean Power Plan has been introduced due to the recent change in administrations at both the state and federal level.

In their 2016 IRPs, DEP and DEC assert that they cannot assess the impact of the Clean Power Plan on their operations due to all the uncertainties surrounding the Plan's implementation. DEP and DEC utilized a mass-based compliance plan and other expansion plans that included a price for carbon emissions as a proxy for carbon regulation. DNCP chose to evaluate and plan for complying with the Clean Power Plan in its IRP, as the Commonwealth of Virginia has elected to continue the development of its state implementation plan.[1] As part of its 2016 IRP, DNCP included a least cost plan that was non-compliant with the Clean Power Plan as well as four compliance plans compliant with the rate-based and mass-based targets.

The Public Staff noted that DEP and DEC did not include expansion plans in their IRPs without a price for carbon. Both utilities (and DNCP) included plans in their 2014 IRPs without a price for carbon. According to the Public Staff, an expansion plan that does not include a price for carbon is more than merely informative. In the 2014 avoided cost proceeding in Docket No. E-100, Sub 140, the Commission held that the generation expansion plans used in avoided cost production cost models should be based on IRP expansion plans that take into account only known and quantifiable costs, and required DEP and DEC to recalculate their avoided energy rates utilizing generation expansion plan scenarios that did not include the costs of carbon. The Public Staff further commented that in the context of DSM and EE programs, the inclusion of carbon has rate implications to customers, both in the evaluation of the cost-effectiveness of programs and in determining the participant incentives to utilities.

The Public Staff commented that in the context of developing a robust long-term resource plan, the Public Staff continues to believe it is appropriate to evaluate the scenarios that both include and exclude explicit costs associated with carbon regulation. While there is currently no such explicit cost, the Public Staff suggested it is appropriate to include scenarios that assume

[1] In its 2014, 2015, and 2016 IRP proceedings, the Virginia State Corporations Commission (VSCC) directed the Virginia Electric and Power Company (operating as DNCP in North Carolina and Dominion Virginia Power in Virginia) to consider and include various options for complying with the Clean Power Plan because of its significance to electric utility resource planning. See VSCC Case No. PUE-2013-00088, Final Order dated August 27, 2014; VSCC Case No. PUE-2015-00035, Final Order dated December 30, 2015; and VSCC Case No. PUE-2016-00049, Final Order dated December 14, 2016.

carbon costs based on the possibility that a known and measurable cost of carbon may exist in the future. As such, the Public Staff recommended that the Commission require DEP and DEC, in future IRPs, to include scenarios that both include and exclude costs associated with carbon regulation.

<u>Commission Conclusions - Carbon Regulation and Clean Power Plan</u>

The Commission acknowledges the uncertainties with regard to carbon regulation generally, and specifically as to the Clean Power Plan. After the Public Staff filed its comments on February 17, 2017, President Trump signed an executive order directing the EPA to review the Clean Power Plan and other greenhouse gas regulations for the power sector.[1] This executive order, EPA's review required by the executive order, and the pendency of the legal challenge to the validity of the Clean Power Plan, continues the uncertainty associated with carbon and its impact on Integrated Resource Planning. The Commission, however, expects the utilities to continue to analyze the impacts of carbon emissions under different scenarios in their planning.

Duke commented that DEC and DEP did not include a scenario that excluded carbon costs in the scenario evaluation portion of their analyses; however, Duke agreed that, given the current political climate and lack of carbon legislation, including scenarios that both exclude and include carbon costs in future IRPs is reasonable until such time that a carbon policy is in place. Therefore, based on the recommendation of the Public Staff and Duke's comments above, the Commission concludes that DEP and DEC should include scenarios in future IRPs or IRP updates, that include and exclude costs associated with carbon regulation.

The Commission also finds and concludes that the methodologies utilized by the utilities to address carbon in their 2016 IRPs are appropriate for planning pending further federal and state actions that provide clarity on the possibility of carbon regulation.

PROJECTED PRICES FOR NATURAL GAS

Beginning with the 2015 IRPs, DEP and DEC migrated to a fuel forecasting methodology for natural gas that included market based prices for the first 10 years of the planning period. This was a change from the methodology utilized in the 2014 IRP where the first 5 years of natural gas prices were based on market data and the remaining years were based off of fundamental pricing. DEP and DEC discussed the rationale behind this move in their 2015 IRP updates. Consistent with the 2015 updates, DEP and DEC utilized the same methodology in their 2016 IRPs based on 10 years of market-based prices.[2]

DNCP utilized forward price for the first 18 months and then blended the forward prices with a fundamental price forecast for the next 18 months to transition to its long-term forecast developed by ICF International, Inc.

[1] Exec. Order No. 13783, 82 Fed. Reg. 16093 (Mar. 31, 2017).

[2] Rebuttal Testimony of Glen Snider, Docket No. E-100, Sub 148 (April 10, 2017), at 17.

Public Staff Comments - Projected Prices for Natural Gas

The Public Staff commented that it appreciates the difficulty in forecasting long-term prices of natural gas as well as other fuel prices, and found reasonable DNCP's reliance on forecasts from ICP International, Inc. However, the Public Staff expressed concerns with the natural gas price forecasts utilized by DEP and DEC in their 2016 IRPs.

The Public Staff commented that the proposed use of forward natural gas prices for ten years by DEP and DEC leads to natural gas prices that it believes to be overly conservative and inappropriate for planning purposes. The Public Staff found more reasonable DNCP's approach of using forward price data for the short-term before transitioning to its long-term fundamental natural gas price forecast.

The Public Staff noted in its comments that the use of an excessively conservative natural gas price forecast is unlikely to alter DEP and DEC's generation expansion plan, however, the use of a low gas price forecast will depress the avoided energy costs that are paid to qualifying facilities, and also reduce the avoided energy costs that are used to evaluate the cost-effectiveness of DSM and EE programs.

The Public Staff recommended that DEP and DEC, in future expansion models, reflect the use of no more than five years of forward natural gas prices.

NCSEA Comments - Projected Prices for Natural Gas

NCSEA noted Duke's reliance on "forward prices" rather than fundamental fuel forecasts in developing IRPs, and by extension their avoided cost calculations. NCSEA requested that the Commission address or determine whether such significant reliance on forward prices in fuel forecasting is appropriate in the context of the avoided cost proceeding. NCSEA noted that in past proceedings, the Commission has addressed the interdependence of the utilities' long-term fuel forecasts and generation expansion plans and has discussed that fuel forecasts drive the utilities' generation planning and generation building decisions.[1]

NCSEA commented that the Commission has previously noted the shortcomings of forward market prices relative to the long-term forecasts, which are prepared by firms whose expertise is in long-term forecasting. According to NCSEA, the Commission has never directed the utilities to construct their respective fuel forecasts using a specific number of years of forward market prices and a specific number of years of fundamental, long-term forecasts even though the Commission has cautioned of the risks associated with the forward prices.

NCSEA noted that it has previously stated and supported its position on the construction of fuel forecasts using a blend of forward prices from futures markets and fundamental-based forecasts in future years through the Affidavit of Ben Johnson, Ph. D., filed in Docket No. E-100, Sub 140, on August 7, 2015. Based on Mr. Johnson's Affidavit, NCSEA contends that fundamental

[1] Order Establishing Standard Rates and Contract Terms for Qualifying facilities, Docket No. E-100, Sub 140 (December 17, 2015), at 24-27.

forecasts are an appropriate source of fuel cost data since they represent an estimate of the price that will be paid by the utility for specific types of fuel purchased at specific dates in the future.

NCSEA commented that in contrast, forward prices from the futures markets are not predictions or estimates of what prices will occur in the future. Rather, forward prices tend to systematically understate the true cost of acquiring fuel at future dates. The prices observed in the futures markets are generally not for the fuel itself, but for contracts that represent a carefully structured, highly standardized bundle of legal rights and obligations. According to NCSEA, utilities do not typically purchase fuel in futures markets in order to receive physical delivery of the fuel at future dates. But, if they were to do so, they would incur substantial additional carrying costs for fuel purchased in this manner, over and above the "forward price" paid for the futures contract itself. NCSEA goes on to state that these carrying costs include interest on their investment and the cost of equity capital during the entire time from the date when they purchase the futures contract until the date when they receive physical delivery of the fuel, months or years later. Therefore, according to NCSEA, futures prices tend to systematically understate the actual cost of acquiring fuel for future delivery, and the magnitude of this understatement becomes more serous the longer the time period over which future prices are being used.

NCSEA argued that fundamentals-based forecasts in future years are more representative of a utility's avoided cost and that it is not appropriate to rely on ten years of forward prices in estimating future avoided cost. NCSEA commented that to the extent forward prices are appropriately relied upon, rather than the fundamental long-term forecasts, it is particularly significant in the context of the biennial avoided cost proceeding, which is currently pending before the Commission in Docket No. E-100, Sub 148. Accordingly, NCSEA requested that the Commission address or determine whether such significant reliance on forward prices is appropriate in the context of the avoided cost proceeding. NCSEA commented that the appropriate reliance on fundamental forecast and future prices, and the appropriate time periods over which these data sources should be used, are issues that are best resolved in the context of the avoided cost proceeding.

Duke Reply Comments - Projected Prices for Natural Gas

Duke's reply comments addressed a number of the Public Staff's concerns, including the position taken by the Public Staff that forward markets are "overly conservative," or too low. Duke noted that in Docket No. E-100, Sub 148, Duke witness Glen Snider, Director of Carolinas Resource Planning and Analytics, presented extensive data demonstrating just the opposite. Duke commented that witness Snider shows that fundamental forecasts have systematically overestimated market prices over the last several years as continued advancements in natural gas fracturing drive down gas prices. Duke goes on to state that a transactable market is neither aggressive nor conservative; it is simply the prevailing market price for forward purchases of natural gas. In fact, over the last few years, both the forward prices and fundamental forecasts have been higher than realized prices, with fundamental forecasts overshooting the mark by a larger margin than forward prices.

Duke noted that the Public Staff recognizes that the forecast of the next 10 years of fuel prices will actually make very little difference in the context of an IRP that is evaluating 40-year generation assets that are projected to come online over the 15-year IRP planning horizon.

However, the 10-year fuel price issue has the potential to directly impact contractual obligations to qualified facilities (QFs) under avoided cost ratemaking. As such, Duke commented that the Public Staff's recommendation to only use five years of liquid market data rather than 10 years of liquid market data is more appropriately addressed in the avoided cost docket as opposed to the IRP docket.

Duke also addressed in its reply comments NCSEA's concerns that forward prices drastically understate the true cost of acquiring fuel for future delivery, and that if utilities actually purchased fuel in futures markets to receive physical delivery at a future date, they would incur substantial carrying costs. Duke commented that purchasing natural gas forwards or futures does not involve substantial carrying costs. To the contrary, such transactions merely involve the contractual agreement of a future price for natural gas. According to Duke, these forward transactions do not involve a payment today for a commodity delivered in the future and as such they do not have "substantial carrying costs."

<u>Commission Conclusions - Projected Prices for Natural Gas</u>

In its March 22, 2016 Order Accepting Filing of 2015 Update Reports (Docket No. E-100, Sub 141), the Commission accepted the update reports filed by the IOUs as complete and fulfilling the requirements set out in Commission Rule R8-60. DEP and DEC utilized a fuel forecasting methodology for the 2015 IRP updates that included market based prices for the first 10 years of the planning period for natural gas. The following excerpt from DEP and DEC's 2015 IRP update reports summarizes the utilities' rationale behind use of this methodology.

> In the 2014 IRP, the first 5 years of natural gas prices were based on market data and the remaining years were based off of fundamental pricing. Market prices represent liquid, tradable gas prices offered at the present time, also called "future or forward prices." These prices represent an actual contractually agreed upon price that willing buyers and sellers agree to transact upon at a specified future date. As such, assuming market liquidity, they represent the markets view of spot prices for a given point in the future. Fundamental prices developed through external econometric models, on the other hand, represent a projection of fuel prices into the future taking into account changing supply and demand assumptions of the changing dynamics of the external marketplace. The natural gas market has become more liquid, and there are now multiple buyers and sellers of natural gas in the marketplace that are willing to transact at longer transaction terms. Due to the evolving natural gas market, DEP and DEC are using market based prices for the first 10 years of the planning period (2016 – 2025O. Following the 10 years of market prices, DEC and DEP transition to fundamental pricing over a 5 year period with 100% fundamental pricing in 2030 and beyond.

In the 2016 biennial proceeding on avoided cost rates (Docket No. E-100, Sub 148), Duke witness Snider provided extensive testimony on market vs. fundamental fuel prices. This matter is currently pending before the Commission.[1] In that docket, witness Snider commented as follows in his rebuttal testimony:

> In Phase 2 of the Sub 140 proceeding, Duke proposed to continue a trend initially begun in recent integrated resource plans of more heavily relying upon forward market price data as a more precise indicator of the near-term future commodity costs of natural gas for purposes of calculating Duke's avoided energy cost rates. Specifically, Duke proposed to rely upon 10 years of forward market price data as a more accurate indicator of the future commodity costs of natural gas and to then transition to fundamental forecast data starting in year 11. However, at the time Duke filed its proposed avoided cost rates in Sub 140 Phase 2, Duke's then pending 2014 IRPs had relied upon only five years of forward market price data before transitioning to reliance on fundamental forecast data for the remainder of the 30 year planning horizon. In its Sub 140 Phase 2 Order, the Commission recognized that changing market conditions supported Duke's increased reliance on forward market price data, acknowledging "the changing nature of the natural gas market and the fact that lower natural gas prices in the short- and long-term will result in benefits to ratepayers in the form of lower-cost electricity rates."[2]

Based on DEP and DEC's 2015 IRP updates and Duke witness Snider's extensive testimony on this subject in the 2016 avoided cost hearing, the Commission accepts that the fuel forecasting methodology utilized by DEP and DEC is appropriate for Integrated Resource Planning in this docket.

The Commission accepts that the fuel forecasting methodology utilized by DNCP is also appropriate for Integrated Resource Planning in this docket.

As discussed in its avoided cost Order in Docket No. E-100, Sub 140,[3] the Commission re-emphasizes the relationship between the IRP and avoided costs and the need for their inputs and assumptions to be consistent. The Commission recognizes, however, that generation expansion plans are less sensitive to changes in fuel forecasts compared to their impact on avoided energy costs that are also used to evaluate the cost-effectiveness of DSM and EE programs. Consistent with the comments of NCSEA and Duke's reply comments, the Commission determines that specific issues related to fuel forecasting methodologies employed by the utilities, are best resolved in the context of the avoided cost proceeding. Accordingly, the Commission's acceptance of fuel forecasting methodologies in the present IRP docket shall not be precedent for or in any manner prejudice decisions to be made in the pending avoided cost proceeding in Docket No. E-100, Sub 148.

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[1] Rebuttal Testimony of Glen Snider, Docket No. E-100, Sub 148 (April 10, 2017) at 5-8 and 15-28.

[2] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 140 (December 17, 2015), at 27.

[3] Id. at 28.

Rather than address the Public Staff's recommendation that would require DEP and DEC to use no more than five years of forward natural gas prices in future expansion models, the Commission will defer to decisions pending in the avoided cost proceeding.

NATURAL GAS ISSUES

Ordering Paragraph No. 15 of the 2014 IRP Order, required that, consistent with the Commission's May 7, 2013 Order in Docket No. M-100, Sub 135, the IOUs shall continue to include with their future IRP submittals verified testimony addressing natural gas issues, as detailed in the body of that Order.

In the Commission's May 7, 2013 Order Approving Rules, Requesting Comments, and Establishing Requirements for Electric Integrated Resource Plans to be Filed in 2014, in Docket No. M-100, Sub 135 (Sub 135 Order), the Commission detailed these natural gas issues:

1. The potential risks inherent in their [the electric utilities'] increasing reliance on natural gas as a generation fuel and the long-term adequacy of North Carolina's gas infrastructure.
2. The electric utilities' plans for procuring the additional gas supplies that would be required by the generation proposed in their IRPs.
3. The electric utilities' plans to ensure long-term gas supply reliability and adequacy.
4. The electric utilities' understanding of how much additional pipeline infrastructure will be needed, and when, due to the combined needs of gas distribution companies and existing and proposed gas-fueled electric generation.
5. The advantages and disadvantages of a second major pipeline being built through North Carolina, and the electric utilities' understanding of the steps that would need to occur to effectuate such construction.

In response to the Commission's 2014 IRP Order, the three IOUs filed testimony in this Docket No. E-100, Sub 147, addressing the issues posed in the Sub 135 Order.

DNCP presented the testimony of Ted S. Fasca, Manager of Generation System Planning. Witness Fasca indicated that although Virginia Electric and Power Company (VEPCO), operating as DNCP in North Carolina and as Dominion Virginia Power in Virginia, has limited gas-fueled generation resources physically located in North Carolina, it plans for and operates its combined North Carolina and Virginia service territory as a single, integrated system. VEPCO manages a balanced mix of fuels that includes fossil (gas, coal, petroleum), nuclear, biomass, and renewable (hydro and solar).

Witness Fasca testified that VEPCO's Virginia electric generating assets are fueled by four major gas pipelines: Transcontinental Gas Pipe Line Company, LLC (Transco), Columbia Gas Transmission (TCO), Dominion Transmission, Inc. (DTI), and Dominion Cove Point LNG, LP (Cove Point). Transco spans from the Gulf of Mexico (GOM) along the east cost up to New York and Pennsylvania. Transco pulls supply from the GOM as well as shale areas in Ohio, Pennsylvania, and West Virginia and is currently the only major gas pipeline in North Carolina. TCO is supplied from the GOM and the Marcellus market areas. TCO does not have any new firm capacity available to supply VEPCO. DTI is primarily centralized in the northeast, spanning Ohio, Pennsylvania, New York, Maryland, Virginia, and West Virginia. DTI has ample supply from the Marcellus and Utica shale regions, but current firm transportation (FT) is limited in VEPCO's service territory. Cove Point connects Cove Point LNG (liquefied natural gas) facility to the Transco, TCO, and DTI pipelines.

According to witness Fasca, VEPCO currently only has one natural gas fueled electric generating unit in North Carolina – the Rosemary Power Station (Rosemary) located in Roanoke Rapids. Rosemary began operation in 1990 and is capable of generating 165 MW. It also has dual-fuel capacity, enabling operation on oil when gas supply is unavailable. Rosemary has 3,183 dekatherms per day (dt/day) of FT on Transco, and, due to the cost of additional FT service for this unit being uneconomic due to the existing air permit limit, VEPCO has no plans to acquire additional FT for this unit. Witness Fasca testified that DNCP intends to continue relying on interruptible transportation (IT) service and the unit's oil backup capability to operate, with limited FT primarily for start-up.

Witness Fasca testified that VEPCO recognizes the abundant supply and low cost of shale gas in recent years and is relying nearly exclusively on natural gas for meeting growth in its electric customer demand. VEPCO plans to continue acquiring FT service for all new large baseload and intermediate gas-fired generating resources. Specifically, he testified that VEPCO has two major CC projects under construction, both of which have FT contracts to fuel them: the Warren County Power Station[1] – 1,337 MW, and the Brunswick County Power Station – 1,375 MW, which is scheduled to be in service in 2016.[2] VEPCO is also planning an additional 3x1 CC plant to be in service in 2019 and is evaluating gas supply options and FT service.

Witness Fasca testified that DNCP executed a Precedent Agreement (PA) with Atlantic Coast Pipeline (ACP) for 300,000 dts/day of FT capacity. Witness Fasca concluded that this additional capacity will benefit DNCP's system portfolio by providing greater access to the Marcellus/Utica supply basins in close proximity to the Brunswick and Greensville CCs.

Witness Fasca presented DNCP's assessment of its natural gas reliability and supply adequacy. He stated that interruptions to a single pipeline are manageable, but additional actions are needed to ensure future reliability and rate stability. He noted DNCP's plans to increase the natural gas pipeline capacity into its service territory, acquire additional FT service on available pipelines, equip future CCs and CTs with dual fuel capability, and continue evaluating opportunities for incremental pipeline capacity. Mr. Fasca indicated that DNCP supports greenfield pipeline projects that allow for future, low-cost expansions that cannot be achieved easily on existing pipelines. He also pointed out that with the eventual reduced capacity constraints on pipelines, pricing should become less volatile and more reliable on peak demand days. Finally, witness Fasca noted that additional pipelines increase the operational flexibility of electric generating plants.

DEP and DEC presented the testimony of Swati V. Daji, Senior Vice President, Fuels & Systems Optimization for Duke Energy Corporation. Witness Daji presented Duke's assessment

[1] The Warren County Power Station commenced commercial operation on December 10, 2014.

[2] The Brunswick County Power Station commenced commercial operation on April 25, 2016.

of the natural gas supply market. Specifically, she stated that the development of shale gas has created a fundamental shift in the nation's natural gas market and has contributed to substantial increases in the supply of natural gas in the United States. Witness Daji noted the Energy Information Administration's projection that shale gas supply will provide over 69% of domestic natural gas production by the year 2040, and noted that the Marcellus and Utica shale gas supply basins are in a period of rapid growth, which should continue. She stated that electric utilities have the opportunity to diversify their gas supply sources across a growing supply.

Witness Daji indicated that DEP has natural gas fueled generation capability of approximately 2,391 MW of natural gas-fired CTs and 2,991 MW of CCs, and that DEC has a total of 3,204 MW of natural gas-fired CTs and 1,403 MW of CCs. Witness Daji indicated that the 2016 IRP base case shows that between 2017 and 2031, DEP is planning to add 5,409 MW of new natural gas-fired generation and DEC is planning an additional 2,481 MW.

In regard to its supply and transportation procurement plan, witness Daji indicated that DEP and DEC operate pursuant to an Asset Management Agreement (AMA) approved by the Commission. In the AMA, DEC is the designated Asset Manager that procures and manages the combined gas supply needs for DEP and DEC, including the scheduling and balancing functions. The AMA also includes a storage agreement. Duke Energy computes a five-year gas usage forecast four times a year and a 15-year forecast updated at least once a year. These forecasts incorporate system load forecasts, market fuel and emission prices, unit capacity ratings and heat rates, and maintenance schedules.

Duke Energy, along with Piedmont Natural Gas Company, Inc. (Piedmont), issued a joint RFP for 900,000 MMBtu (one million British thermal units) per day, pursuant to which 725,000 MMBtu/day would belong to DEP and DEC, beginning November 1, 2018, with an option for additional quantities. The winning bidder was the proposed Atlantic Coast Pipeline (ACP). Duke Energy believes a second major pipeline in the State would offer significant benefits to gas generation customers as well as other end users of natural gas. These benefits include the provision of needed infrastructure to support gas generation growth, a significant opportunity to enhance supply diversity and reliability, and enhanced flexibility, reliability, and integration into the North Carolina gas distribution infrastructure. According to Duke, additional benefits are the promotion of a long-term competitive environment for future pipeline capacity additions, diversification of the natural gas supply by accessing shale gas supplies in the Marcellus and Utica shale basins, and the introduction of an additional gas supplier, which would increase diversity of natural gas supply and credit portfolios. Duke Energy was unable to identify any disadvantages associated with this second major pipeline in the State.

Witness Daji indicated that the ACP project is pursuing its Final Environmental Impact Study, which is planned for completion by June 30, 2017, and final approval of need from the FERC by September 13, 2017. Based on this updated schedule, construction of the ACP should begin thereafter, with an in service date of late 2019 rather than late 2018 as originally projected.

Public Staff Comments - Natural Gas Issues

The Public Staff concluded that DEP, DEC, and DNCP made a reasonable assessment of their needs for natural gas infrastructure in order to meet their growing dependence on natural gas to provide electric generation. According to the Public Staff, the utilities also demonstrated their understanding of how an interstate pipeline is planned, approved, and built, including the open season period to determine the market for the pipeline and associated costs. Additionally, the Public Staff commented that the IOUs are knowledgeable about the natural gas supply market, as well as the pipeline planning and build-out in order to move the natural gas supply to their electric generation facilities. It appears that the ACP will indeed be the second major natural gas pipeline into the State of North Carolina. The utilities adequately set out the benefits of this additional pipeline.

The Public Staff recommended that the electric utilities and the natural gas distribution companies continue to work together with ACP in planning for adequate pipeline capacity to meet electric generation needs. The Public Staff also recommended that the electric utilities consider natural gas electric generation facilities that also can operate on an alternate fuel.

NC WARN Comments - Natural Gas Issues

NC WARN noted in its initial comments, that one of the most glaring deficiencies in the Duke IRPs filed in this docket is the proposed massive investment by both utilities in new natural gas infrastructure, which will further exacerbate the climate crisis.

NC WARN further commented that Duke remains heavily reliant on construction of new natural gas infrastructure, including power plants and new natural gas pipelines, such as the Atlantic Coast Pipeline. NC WARN stated that Duke Energy's increasing dependence on natural gas is troublesome because of the likely future cost increase from fuel supply and production limitations[1] and the impacts of methane from natural gas infrastructure on the climate crisis.[2] According to NC WARN, rather than addressing these issues squarely, the IRPs forecast the need for more and more natural gas plants. DEC plans to add 2,481 MW of new natural gas capacity by 2031 and DEP plans to add 5,409 MW of new natural gas capacity by 2031.

NC WARN also filed reply comments that specifically addressed the testimony on natural gas issues by Swati V. Daji. NC WARN noted that Nancy LaPlaca, J.D. drafted the reply comments which asserted that:

1. Future U.S. natural gas supplies are overestimated, which could result in stranded assets.
2. Purchasing gas from its own subsidiary will not provide Duke Energy with a "diverse" and reliable fuel supply.
3. Methane from natural gas has an enormous effect on climate change, as its greenhouse gas warming potential is 86 times worse than carbon dioxide over 20 years.

NC WARN's basis and support for these assertions are detailed in their reply comments, including a number of references to studies, forecasts, papers, and other documents submitted in support of its positions. NC WARN commented that the supply of natural gas in the U.S. is

[1] J. David Hughes, 2016 Shale Gas Reality Check, Fall 2016. http://www.postcarbon.org/2016-shale-gas-reality-check/.

[2] Dr. Robert W. Howarth, "Methane emissions: The greenhouse gas footprint of natural gas," September 2016. http://www.eeb.cornell.edu/howarth/summaries CH4 2016.php.

seriously overestimated, putting ratepayers at risk of rising prices at best, and stranded assets at worst. NC WARN stated that historic production data shows that endless future supplies of shale gas are based on unrealistic forecasts by the U.S. Energy Information Administration (EIA). NC WARN commented that the EIA (and Duke Energy in its planning) expects natural gas production to continue to rise decades into the future, utterly ignoring the fact that shale gas wells decline very quickly over the first three years, and that the oldest U.S. shale gas plays, which have been producing for less than 20 years, are in the advanced stages of decline.

One source referenced by NC WARN is the work of Arthur E. Berman, a geological consultant with 37 years of experience in petroleum exploration and production, as well as financial analysis with a focus on the energy sector. NC WARN commented that Berman has been alerting investors for years that the "magical thinking" behind believing shale gas can continue to be cheap, abundant and profitable defies the rules of economics. According to NC WARN, Berman disputes the findings of the EIA's 2016 Annual Energy Outlook saying that it "sparkles with pixie dust."[1] According to NC WARN, Berman points out that although the Marcellus still has gas, and will for many years, the gas cannot be profitably brought to market at the current low prices. NC WARN commented that Berman clearly states that when gas prices are below the cost of production, companies cannot make a profit.

Finally, NC WARN commented that in an era of rapidly decreasing costs for clean energy, and the questionable future supplies and cost of natural gas, it is irresponsible for Duke Energy to promote further reliance on fracked gas in the IRPs. If the cost of natural gas either rises dramatically, or is not available over the 30-year life of the natural gas plants, ratepayers could be stuck with stranded assets.

Addressing methane, NC WARN commented that the huge increase in fracking in the U.S. is driving a spike in methane emissions and, according to the most recent report by the Intergovernmental Panel on Climate Change (IPCC) issued in 2013, methane's effect on the climate is 86 times that of carbon dioxide over a 20-year timeframe. According to NC WARN, decisions about the use of natural gas and its impacts on the climate should consider the 20-year timeframe, rather than the longer, 100-year timeframe which causes natural gas to appear to be promoted as more climate-friendly than it actually is.[2]

NC WARN commented that Duke Energy did not consider lifecycle GHG emissions that would result from the buildup of natural gas infrastructures presented in the IRPs. According to NC WARN, Duke Energy fails to provide reasoning or methodology for neglecting to address lifecycle GHG emissions estimates for nearly 8,000 MW of new natural gas power plants, making it impossible for the Commission to evaluate how large cumulative emissions will be over the next thirty years – the proposed lifetime of these projects. Duke Energy must analyze the possibility that additional natural gas infrastructure will lock-in fossil fuel use for decades to come and discourage or prevent the construction of carbon-free energy sources, which has significant implications for the climate. NC WARN further commented that because the

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[1] www.albertman.com/shale-gas-magical-thinking-and-the-reality-of-low-gas-prices/.

[2] https://thinkprogress.org/how-the-epa-and-new-york-times-are-getting-methane-all-wrong-eba3397ce9e5#.s5zcjd205. .

construction and operation of new interstate natural gas infrastructure ultimately contributes to increased GHG emission, Duke Energy must fully evaluate these impacts, compare alternatives, and develop mitigation measures as part of its planning.

Duke Reply Comments - Natural Gas Issues

Duke noted that in its April 17, 2017 Reply Comments, NC WARN regurgitates the claims it has attempted to make in several recent past proceedings, including in Docket No. E-2, Sub 1089 (Western Carolinas Modernization Project) and Docket Nos. E-2, Sub 1095, E-7, Sub 100 and G-9, Sub 682 (the Duke Energy/Piedmont Natural Gas merger), that future natural gas supplies in the United States are overstated and that methane from natural gas has an impact on climate change. Rather than engaging in policy arguments that Duke contends are irrelevant to this IRP proceeding, Duke commented that it respectfully asserts that if NC WARN seeks to abolish the use of natural gas or seeks to change the laws and regulations governing the extraction or processing of natural gas or their attendant environmental regulations, those arguments should be made before Congress, the North Carolina General Assembly or the appropriate federal or state agency charged with implementing environmental policy.

Duke further submitted that NC WARN's IRP Comments and Reply Comments are not realistic proposals if the State of North Carolina wants to ensure reliable and affordable electricity is available to the residential, commercial and industrial customers over the IRP planning horizon, as Duke is obligated to do. According to Duke, renewable resources, EE and DSM are important and increasingly significant components of DEC and DEP's IRPs, but they simply cannot realistically be relied upon in the almost exclusive nature that NC WARN has alleged. In contrast to the NC WARN "plan," the Duke's IRPs present robust and balanced portfolios of diverse supply and demand-side resources that will cost-effectively and reliably serve customers' short and long-term needs across a range of many possible future scenarios. Duke stated that the comments of NC WARN should be disregarded.

Commission Conclusions - Natural Gas Issues

Based on a review of witnesses Fasca's and Daji's filed testimony in this docket, along with the review and comments of the Public Staff, the Commission finds that the IOU's responses to the issues raised in the Commission's Sub 135 Order adequately address the Commission's concerns. The Commission does not anticipate the need to have such detailed testimony to be filed in subsequent IRPs or IRP updates. This is not to detract from the importance the Commission places on the identification and implementation of plans to address natural gas issues, including those identified in the Sub 135 Order. The Commission has confidence in the ability of the IOUs to timely and effectively address natural gas issues related not only to technologies employed but also the science.

As the Commission concluded in the preceding section on Projected Prices for Natural Gas, the IOU's fuel forecasting methodologies are appropriate for Integrated Resource Planning. The

Commission is of the opinion that the current scenario planning and risk analyses utilized by the IOU's effectively address key market drivers such as natural gas supplies.[1]

As also discussed above, the Commission expects the IOUs to continue to analyze the impacts of carbon emissions under different scenarios in their planning, despite the continuing uncertainties about future carbon regulation. In addition, the Commission notes that the impacts of carbon are based on cost assumptions relative to the Clean Power Plan or other carbon regulations. Therefore, the Commission is of the opinion that the current assessments of carbon included in the IRPs are sufficient for now without requiring a broader approach to assess lifetime GHG emissions (including methane) in the manner recommended by NC WARN.

The Clean Power Plan does not address methane. In fact, the EPA recently instituted a 90-day stay on the Obama administration's limits on methane emissions from oil and gas drilling sites, allowing the fossil fuels industry to submit another round of comments before the rule goes into effect. Moreover, NC WARN's concern with methane emissions is focused primarily on methane leakage and venting within the natural gas production and distribution process. The Commission does not regulate natural gas extraction or interstate transportation. However, the Commission does condition its issuance of CPCNs for electric generating plants - whether fueled by nuclear, coal, natural gas or other sources - on compliance with all applicable laws and regulations, including any environmental permitting requirements. The Commission finds and concludes that such required regulatory approvals and compliance by the utilities are sufficient to address the environmental concerns raised by NC WARN.

The Commission supports the Public Staff's recommendation that the utilities continue to develop methods of quantifying the benefits of fuel diversity. The Commission also supports the Public Staff's recommendation that the utilities consider natural gas electric generation facilities that can also operate on an alternate fuel.

RELICENSING OF EXISTING NUCLEAR PLANTS

Public Staff Comments - Relicensing of Existing Nuclear Plants

The Public Staff commented that one of the significant issues faced by the utilities is the pending expiration of operating licenses for nuclear energy resources in the next 20 to 30 years. According to the Public Staff, current schedules call for retirement of approximately 5,900 MW in the 2030 to 2034 period and the loss of an additional approximately 8,400 MW in the 2036 to 2046 period. The following table summarizes the current license expiration dates for the utilities' nuclear facilities.

[1] DNCP stated on page 80 of its IRP, "Key drivers include market structure and policy elements that shape allowance, fuel and power markets, ranging from expected capacity and pollution control installations, environmental regulations, and fuel supply-side issues."

Name	Utility	Summer Capacity (MW)	License Expiration Date
Robinson Unit 2	DEP	741	July 2030
Surry Unit 1	DNCP	838	May 2032
Surry Unit 2	DNCP	838	January 2033
Oconee Unit 1	DEC	847	February 2033
Oconee Unit 2	DEC	848	October 2033
Oconee Unit 3	DEC	859	July 2034
Brunswick Unit 2	DEP	932	December 2034
Brunswick Unit 1	DEP	938	September 2036
North Anna Unit 1	DNCP	948	April 2038
North Anna Unit 2	DNCP	944	August 2040
McGuire Unit 1	DEC	1158	June 2041
McGuire Unit 2	DEC	1158	March 2043
Catawba Unit 1	DEC	1140	December 2043
Catawba Unit 2	DEC	1150	December 2043
Harris Unit 1	DEP	928	October 2046

The Public Staff noted that the Nuclear Regulatory Commission (NRC) is in the process of developing draft technical guidance for subsequent license renewal (SLR)[1] that may ultimately provide an option to operators of commercial nuclear power facilities for extension past the current 60-year licenses. The Public Staff commented that any additional license extension will be evaluated by the utility based on the specific risks and costs associated with each unit. The NRC has stated that it expects the first requests for extending unit life to 80 years to be filed in the 2018 to 2019 period.

The Public Staff noted that while there is uncertainty whether further license extensions may be granted, DEC's Oconee and DNCP's Surry and North Anna nuclear plants have been identified as candidates for license extension beyond 60 years.[2] On November 15, 2015, DNCP filed a letter of intent to pursue a second license renewal for Surry Units 1 and 2 by the end of first quarter 2019.[3] The Public Staff speculated that should license extensions for some or perhaps even all of the existing units be approved and be determined to be economic, the utilities' energy and

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[1] Nuclear Regulatory Commission, Subsequent License Renewal, online at: https://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal.html.

[2] See, http://www.nytimes.com/2014/10/20/business/power-plants-seek-to-extend-life-of-nuclear-reactors.html?emc=eta1

[3] DNCP included the Letter of Intent as Exhibit 3Y in its 2016 IRP (see p. A-101).

capacity needs and forecasted construction schedule of new generation, as detailed in the 2016 IRPs, would be altered significantly. DEP has indicated that it does not currently plan to seek a second license extension for Robinson Unit 2. The 2016 IRP indicates that Robinson 2 is scheduled to be shut down following the expiration of its current operating license in July 2030.

The Public Staff recommends that the Commission direct the utilities in future IRPs to include a discussion and evaluation of potential subsequent license renewals for all of their existing nuclear units, including an evaluation of the risks and required costs for upgrades, and to reflect any such relicensing plans in future IRPs.

Duke Reply Comments - Relicensing of Existing Nuclear Plants

Duke commented that in making its recommendation, the Public Staff states that DEC's Oconee Nuclear Plant has been identified as a candidate for license extension, but other nuclear units, including DEP's Robinson Unit 2 have not. Duke stated that it would like to clarify, however, that they have made no decisions yet on which nuclear units will be considered as license extension candidates. Duke noted that for planning purposes, the IRP base case assumes retirement at the end of the current license for all nuclear units. Duke also noted that in the 2016 IRPs, it ran a license extension sensitivity which included an assumed 20-year extension of all nuclear units beyond the current 60-year license.[1] Duke commented that it is willing to include a sensitivity for license extensions for existing nuclear assets in future IRPs.

Duke commented that the nuclear industry is in the initial stages of pursuing SLR for the fleet of operating nuclear power plants. The NRC has determined that no changes are required to the License Renewal regulation (10 CFR Part 54) but regulatory guidance documents will need to be updated to address extending operating licenses to 80 years. These new guidance documents, NUREG-2191 and NUREG-2192, have been drafted by the NRC staff and are expected to be finalized and published in the Federal Register in July 2017. Duke noted that it is currently evaluating pursuing SLR for its nuclear fleet but, at this time, no decision has been made. Duke commented that DEC and DEP believe that the uncertainty regarding license extensions combined with the new nuclear long development cycle (10-15 years to license and construct) makes it imperative that DEC and DEP plan for these assets as if they will not be available, then adjust the IRPs as more information becomes available.

DNCP Reply Comments - Relicensing of Existing Nuclear Plants

DNCP commented that with respect to existing generating facilities, the Public Staff recommended that the Commission direct the IOUs in future IRPs to include a discussion and evaluation of potential SLRs for all of their existing nuclear units, including an evaluation of the risks and required costs for upgrades, and to reflect any such relicensing plans in future IRPs. DNCP commented that DNCP commits to include such discussion in its future IRPs and has already provided this type of information in Section 5.2.2 of its 2017 IRP filed in this docket on May 1, 2017.

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[1] 2016 IRPs, at p. 65.

Commission Conclusions - Relicensing of Existing Nuclear Plants

The Commission agrees with the Public Staff's recommendation that the utilities should include a discussion and evaluation of potential SLRs for all of their existing nuclear units, including an evaluation of the risks and required costs for upgrades, and to reflect any such relicensing plans in future IRPs. The Commission accepts the discussion and analyses included in the current docket as adequate. However, these should be expanded upon in future IRPs, consistent with the Public Staff's recommendation and especially as guidance documents on the requirements for an SLR are finalized.

NEW NUCLEAR PLANTS

The DEC and DEP IRP's continue to include new nuclear generation as a carbon-free, cost-effective, reliable option within Duke's resource portfolios. DEC's Base Case models commercial operation of the Lee Nuclear Units in 2026 and 2028. While DEP's Base Case does not call for DEP to construct additional self-owned nuclear generation before 2030, it is considered in the IRPs' alternative Joint Planning Case of DEC and DEP. The Joint Planning Case projects shared DEP-DEC ownership of the Lee Nuclear Units in 2026.

The DNCP IRP notes that DNCP is in the process of developing a new nuclear unit, North Anna 3. Based on the expected schedule for obtaining the Combined Operating License (COL) from the NRC, the Virginia State Corporation Commission certification and approval process, and the construction timeline for the facility, the earliest possible in-service date for North Anna 3 is now September 2028. This in-service date was delayed one year from the 2015 plan. The 2029 capacity year would support the option to develop North Anna 3 prior to the Clean Power Plan compliance plan date of 2030, if the Clean Power Plan comes to fruition.

SACE, NRDC, and the Sierra Club Comments - New Nuclear Plants

SACE, NRDC, and the Sierra Club contended that nuclear is not part of a least-cost portfolio. SACE, NRDC, and the Sierra Club commented that construction of new nuclear is fraught with risk and uncertainty, as demonstrated by the cost overruns and construction delays at the V.C. Summer and Vogtle nuclear plants. SACE, NRDC, and the Sierra Club noted that Daymark's analysis shows that despite the Lee Nuclear Units' inclusion in DEC's 2016 IRP, the Lee Nuclear Units are not economic. SACE, NRDC, and the Sierra Club noted that in multiple model runs, Daymark's Aurora model did not select even one nuclear unit. DEC instead "forced" the nuclear units into its IRP and appears to consider nuclear plants as necessary to achieve a System Mass Cap carbon-reduction scenario. However, SACE, NRDC, and the Sierra Club submitted that Daymark's analysis shows that this scenario can be achieved at a lower cost with alternatives to nuclear power.

Duke Reply Comments - New Nuclear Plants

Duke commented that it is apparent that most of SACE, NRDC and the Sierra Club's argument that the IRPs are not "least-cost" hinges on DEC's inclusion of new nuclear resources. As stated in the DEC IRP, Duke acknowledged that the portfolios that include Lee Nuclear are not the least cost from a revenue requirement perspective. Duke commented, however, that at the time the IRPs were developed the plight of carbon emission legislation was unclear, but it was reasonable to assume that some carbon restrictions would be in place in the early to mid-2020s based on the status of the Clean Power Plan at the time. Duke noted that with the potential for stringent carbon emission targets, the assumption that existing nuclear units would not be relicensed, uncertainty of future fuel prices, and in keeping with previous IRP filings, DEC decided that inclusion of new nuclear generation in the late 2020s would be prudent from a planning perspective. Further, the timing and reasonableness of the need for new nuclear generation continue to be evaluated as carbon legislation, natural gas prices, and nuclear relicensing costs change over time.

Commission Conclusions - New Nuclear Plants

The Commission finds that the analyses and methodologies incorporating additional nuclear capacity and energy into the utilities' IRPs are appropriate for planning in this docket. The Commission recognizes the significant uncertainties that must be addressed before any utility decides to move forward with building new nuclear generation. Recent developments with the V.C. Summer and Vogtle units only serve to reinforce the importance of the planning and inherent risk assessments as well as the on-going scrutiny of actions taken. Finally, in response to an intervenor's request for a show cause order, the Commission issued an Order on May 15, 2017, in Docket No. E-7, Sub 819 denying the request and requiring DEC to file additional information about its expenditures and planning for the Lee Nuclear Units.

SOLAR ENERGY

Public Staff Comments - Solar Energy

The Public Staff commented that for both DEP and DEC, the assumption about solar's contribution to peak capacity has a significant impact on future capacity requirements. According to the Public Staff, even a small adjustment in the percent of nameplate capacity available at peak demand has the potential to delay or even eliminate the need for additional capacity. As such, the Public Staff recommended that the issue of aggregate solar generation coincidence at peak for both winter and summer be evaluated further, given the growing importance of solar generation in North Carolina.

SACE, NRDC, and the Sierra Club Comments - Solar Energy

SACE, NRDC, and the Sierra Club commissioned expert analyses of the 2016 Duke IRPs and supporting documents. SACE, NRDC, and the Sierra Club commented that these expert consulting firms, such as Daymark Energy Advisors, concluded that Duke prematurely limited the amounts of solar photovoltaic energy.[1] Daymark's review of the Duke IRP identified constraints placed on the capacity expansion options as a key concern. To test the sensitivity of the results to these constraints, Daymark analyzed select scenarios with reduced constraints on the long-term capacity (retirements and additions) available to Duke. Based on these tests, Daymark determined

[1] Duke Energy's Resource Plans for the Carolinas: An Evaluation and Alternative Approach, Daymark Energy Advisors (February 17, 2017) for Natural Resources Defense Council, Sierra Club and Southern Alliance for Clean Energy, Docket No. E-100, Sub 147 (May 10, 2017), Attachment D, pp. 2 & 7.

that relieving constraints on the amount of solar PV led to the economic selection of additional solar capacity.[1] As noted in their report, Daymark utilized data from the Duke model and other publicly available data to construct additional local solar and imported wind configurations as supply options for the model to test against the nuclear and natural gas fired units already available for expansion. Up to seven 500 MW blocks of solar in both DEC and DEP was made available to the capacity expansion module. In addition, five blocks of 100 MW wind from Oklahoma and five blocks of 100 MW Tennessee wind were made available in DEC and five blocks of 50 MW wind from Oklahoma were made available for selection in DEP. For both DEC and DEP service areas, all blocks of solar and wind modeled for capacity selection were in fact selected. Overall, this scenario built approximately 3800 MW less thermal capacity while building approximately 8000 MW of additional renewables. According to the Daymark Report, this scenario indicates that there are higher volumes of renewable generation that would lower total system costs and reduce Duke's system carbon emissions.

The Daymark Report noted that Duke appears to have more room on their system for solar PV, as Duke had limited it to 10%. The conclusion in the report was this limit did not result from detailed studies but was considered as judgement.

SACE, NRDC, and the Sierra Club commented that Duke undervalues the capacity that solar provides to the DEC and DEP systems. SACE Director of Research John D. Wilson conducted an analysis[2] of capacity equivalent values for solar energy resources, using data supplied by Duke and by Clean Power Research (CPR). The analysis compared the Duke and CPR data and found that both Duke's data and its method for calculating solar capacity values were severely flawed, resulting in a dramatic undervaluing of solar's capacity benefit to the DEC and DEP systems. The analysis concluded that solar contributes far more to summer and winter peak resource needs than Duke assumed in its IRPs. SACE, NRDC, and the Sierra Club commented that the results of this analysis have important implications not only for Duke's treatment of solar resources in its IRPs, but also for solar avoided costs.

Mr. Wilson's report stated that DEC and DEP undervalue solar because they assess its contribution to peak using what appears to be a simplistic seasonal average of solar capacity factors during certain hours. According to the report, this method is flawed because it gives the same weight to on-peak solar generation (e.g. during the hottest, sunniest hour of a peak load afternoon) as to off-peak generation. SACE's analysis of Clean Power Research's solar generation simulations shows that instead of 44-46%, the summer capacity equivalent value of solar power should be 47-65%, depending on utility and solar technology. For the winter capacity equivalent value, Duke's value of 5% should be increased to 15-26%. As noted in the report, these calculations are derived directly from two hourly datasets covering the 1998-2015 time period. One dataset includes the actual hourly system load and year-ahead peak load forecast for the DEC and DEP planning areas. According to the report, this data is filed on FERC Form 714. The second dataset is simulated hourly generation profiles for fixed mount and single axis tracking PV systems

[1] Id. p. 9.

[2] Analysis of Solar Capacity Equivalent Values for the Duke Energy Carolinas and Duke Energy Progress Systems, John D. Wilson (February 16, 2017) for Natural Resources Defense Council, Sierra Club and Southern Alliance for Clean Energy, Docket No. E-100, Sub 147 (February 17, 2017).

at six locations in the DEC and DEP service areas. This data was provided to SACE by Clean Power Research using its SolarAnywhere model.

By aligning historical system load data with simulated solar generation, the report states that actual performance of solar PV systems can be evaluated under a range of recent meteorological conditions. The 1998-2015 coverage allows for nearly 144,000 comparisons of hourly system load (for each utility) with hourly solar generation. The report notes that this provides an opportunity to conduct a robust statistical analysis of the correlation of solar generation to system load during peak periods.

The report states that taken together, the correlation of higher solar generation with peak load days and the omission of later morning winter peak hours from Duke's capacity equivalence method justifies a significant increase in both the summer and winter capacity equivalent values for fixed mount systems. Furthermore, for single axis tracking systems, the recommended capacity equivalence values are still higher, due to their superior performance in tracking the sun during early morning winter peaks and late afternoon summer peaks. The report concludes that Duke Energy's omission of any distinction by technology type is a significant oversight in its resource planning.

Duke Reply Comments - Solar Energy

Duke commented that DEC and DEP continue to evaluate solar generation profiles, and during winter months the data consistently points to a contribution to peak of approximately 5% during the winter peak hour of 7:00 a.m. to 8:00 a.m. for fixed tilt solar facilities. Duke noted that the majority of winter peaks occur before 7:30 a.m., and at this time in the morning, solar generation is at or near 0% output. Additionally, as single-axis tracking solar facilities become more prevalent on the Duke system, DEC and DEP will evaluate including those facilities, along with their solar generating profiles, in future IRPs. Duke further commented that to the extent solar tracking facilities provide more generating output during the peak hour of 7:00 a.m. to 8:00 a.m., that contribution to peak will be included for those facilities in the IRP evaluation. Duke noted that because DEC and DEP are winter planning, summer solar contribution to peak will not impact their needs for future capacity.

Duke commented that through data requests, Duke requested the inputs into SACE's study that they used to assert that DEC and DEP's 2016 IRPs were allegedly not compliant with Commission requirements and did not represent the "least-cost mix" of resources. Duke noted that when SACE responded that the number of inputs was too voluminous to provide, Duke simply requested the levelized cost of wind/solar energy and the capacity cost of wind/solar resources utilized in their Aurora model along with their corresponding capacity factors. Duke commented that it did not receive this data until after the close of business hours on May 9, 2017, and, therefore, have not had adequate time to quantitatively analyze SACE's assertions.

Duke commented that SACE, NRDC, and the Sierra Club argue that greater reliance on wind and solar generation, along with increased reliance on EE programs, would defer the need for new natural gas generation and would provide for a lower cost portfolio. Duke commented that these arguments are misplaced and noted that DEC and DEP have shown that they are now winter planning utilities, and as such, solar generation does not have the ability to defer the need for new generation. Additionally, a sensitivity of higher levels of solar penetration led to higher revenue requirements. Finally, Duke commented that in the 2016 IRP process, the System Optimizer was allowed to select additional solar generation, and it only selected incremental generation in the stringent carbon scenarios much later in the planning horizon.

Commission Conclusions - Solar Energy

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that the utilities' modeling of solar energy and capacity as presented in the 2016 IRPs are reasonable and appropriate for planning purposes in this docket.

However, the Commission finds merit in the Public Staff's recommendation that the issue of aggregate solar generation coincidence at peak for both winter and summer be evaluated further, given the growing importance of solar generation in North Carolina. SACE's Director of Research, Mr. Wilson, utilized in his analysis a methodology that may provide for a more robust statistical analysis of the correlation of solar generation to system load during peak periods. Without taking a position on the merits of this approach, the Commission considers that a more rigorous analysis similar to that employed by Mr. Wilson, may be warranted and consistent with the Public Staff's recommendation. The Commission notes Duke's position that it did not have adequate time to quantitatively analyze SACE's assertions. Therefore, the Commission concludes that Duke should include in a future IRP, an analysis of the methodology employed by Mr. Wilson and any recommended changes to DEC and DEP's current approach.

WIND ENERGY

MAREC Comments - Wind Energy

MAREC commented that wind energy costs have fallen by 66% over the past seven years,[1] and wind energy represents an increasingly competitive form of energy. In addition, by acting quickly to incorporate wind, the full benefits of federal tax credits can be realized.

MAREC noted that the DEC and DEP filings include no wind energy project additions in their forecasts. Further, MAREC commented that the only statements by DNCP in its 2016 IRP with respect to the viability of onshore wind resources were as follows:

> In the past two years, DNCP has evaluated approximately 310 MW of onshore wind third party alternatives, none of which were located in Virginia. While these projects would be less expensive than DNCP's self-build wind options (both onshore and offshore), they were not competitive against new gas-fired generation and at the time of evaluation, were not expected to contribute toward the Commonwealth meeting its CPP requirements and therefore rejected.[2]

[1] Lazard's Levelized Cost of Energy – Version 10.0, December 2016 at p. 10: https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf.

[2] DNCP IRP at 103.

DNCP continues to pursue onshore wind development; however, there is a limited amount of onshore wind available within or near its service territory. Only three feasible sites have been identified by DNCP for consideration of onshore wind facilities. These sites are located in Virginia, on mountaintop locations.[1]

MAREC commented that the likely explanation for failure of DNCP to incorporate any onshore wind energy capacity in any of its study plans is DNCP's use of a price of $104.02 per MWh, when comparing wind energy to solar and other resources. MAREC commented that this price for wind for purposes of planning is excessively inflated and therefore not at all representative of wind pricing. According to MAREC, the price of wind utilized by DNCP in its IRP modeling is not based in reality. MAREC commented that the same could be said about the prices utilized by DEC and DEP, as wind did not make it out of the screening process in their IRP analyses. DNCP uses estimates in its IRP that are 3-4 times higher than documented market prices for wind energy contracts. MAREC noted that if DNCP performed a true evaluation of market based wind energy prices, it would have found that the pricing for wind is competitive with other generating resources and, in particular, other renewable energy resources.

The bottom line, according to MAREC, is the utilities failed to carefully consider wind for its competitive pricing, its fuel hedge value, the value it provides as a component of a diverse generation supply resource and the economic development value it provides to North Carolina.

MAREC recommended:

1. That the Commission direct the IOUs to evaluate the market prices for all renewable energy resources for REPS compliance, including seeking additional renewable energy diversity when prices of the various renewable resources are comparable.
2. That the Commission direct the IOUs to conduct RFPs for renewable energy as soon as possible to get the maximum value of the Production Tax Credit. The RFPs should be conducted for long-term PPAs that bundle wind energy and renewable energy certificates to give consumers the benefit of stable pricing and the hedge value of wind energy pricing. The RFPs can be conducted in a manner that successful bids should not be in excess of a price limitation approved by the Commission.
3. That the Commission direct DEC and DEP to include energy pricing for wind and other resource in future cost sensitivity analyses.
4. That the Commission should direct DNCP to reevaluate the pricing it has utilized for purposes of its 2016 IRP. DNCP should be required to conduct a market analysis of wind pricing that should be sufficiently detailed and reviewable.

Duke Reply Comments - Wind Energy

Duke commented that the main locations for wind energy generation in the Carolinas are the North Carolina mountains and onshore coastal regions. With ridge laws prohibiting wind turbine construction in the North Carolina mountains and siting issues along the coast, there are real physical limitations to the amount of wind power that could be built in the Carolinas currently.

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[1] DNCP IRP at 110.

Duke further noted that while the National Renewable Energy Laboratory study cited by MAREC may have determined a large potential for North Carolina wind projects, the prohibitive laws and siting issues continue to hinder wind facility construction in North Carolina.

Further, Duke commented that its wind energy pricing is representative of a facility with 100-meter plus towers and larger turbines in order to gain the energy yield necessary to potentially justify construction of a facility. According to Duke, more difficulty lies in locating a wind energy project near a load center with adequate, useful land potential. Duke notes that the Department of Energy and the U.S. Energy Information Administration pricing is very generic and does not account for many of the intricacies of locating a wind farm or any other project.

Duke concluded that DEC and DEP adequately considered wind and all other potential renewable energy resources in preparing their 2016 IRPs. Duke commented that it recognizes the valuable potential that new wind energy resource development could provide. However, DEC and DEP analyzed wind and other generation technologies and selected the resource plans that best meet Duke's needs to provide the reliable, least-cost resource mix as required by North Carolina's Integrated Resource Planning and REPS laws.

DNCP Reply Comments - Wind Energy

DNCP commented that it disputes MAREC's arguments that the wind energy resource pricing presented in the 2016 IRP is overstated. DNCP noted that the installed cost of wind energy in its plan is based on its self-build wind options. These potential projects are located in the mountainous regions of Virginia where expected capital construction costs are projected to be higher than an equivalent project located on a relatively flat, open site, similar to those cited by MAREC which are located in the Great Lakes region or the interior region of the United States. DNCP also cited the 310 MW of third-party alternative projects which were evaluated over the 2015-2016 period in the 2016 IRP. DNCP commented that these projects, while less expensive than DNCP's self-build wind options, did not yield a positive net present value for customers in the analyses performed on the proposals received. Because the projects did not produce overall net benefits in their individual proposal analyses based on economics, they would not be chosen in an IRP study.

DNCP also noted that the wind energy prices used in the 2016 IRP are consistent with the processes and methods utilized in prior IRPs that have been accepted as reasonable for planning purposes by the commissions in North Carolina as well as Virginia. DNCP commented that in contrast, many of the wind energy costs cited by MAREC are either national or regional averages that cannot be applied to the expected cost of installing wind on a specific site in North Carolina or Virginia. Further, DNCP commented that among all available supply-side resources, onshore wind is expected to provide the lowest capacity value, or the lowest contribution to meeting peak demands.

Based on the foregoing, DNCP commented that it continues to find the wind energy pricing and resource analysis presented in the 2016 IRP to be reasonable and appropriate for planning purposes. MAREC's recommendation that DNCP be required to perform additional market analysis of wind pricing should be rejected.

Finally, DNCP noted that the 2016 IRP explains that both DNCP self-build and third-party alternative wind energy resources were not competitive against new gas-fired generation at the time of evaluation. However, DNCP stated that it has and continues to evaluate all forms of third party market alternatives, including wind, as part of its ongoing resource planning process. Accordingly, MAREC's recommendation that the Commission order it to develop a wind resource-focused RFP is not necessary and should be rejected at this time.

Commission Conclusions - Wind Energy

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that the utilities' wind energy pricing and resource analyses presented in the 2016 IRPs are reasonable and appropriate for planning in this docket. The Commission finds merit in the reply comments of DNCP concerning the 310 MW of third-party alternative project proposals evaluated over the 2015-2016 period in the IRP. DNCP specifically commented that these projects did not yield a positive net present value for customers in the analyses performed on the proposals received.

As circumstances exist today and as it stands on this record, the Commission is not persuaded that it should require the utilities to conduct RFPs for renewable energy as soon as possible in order to get the maximum value of the Production Tax Credit (PTC). This was the recommendation by MAREC. However, the Commission determines that this issue is best resolved within the overall context of least cost planning for the production of an adequate and reliable supply of electricity. Indeed, the Commission does not want the utilities to plan on building a particular generation resource mainly because a PTC is available for that resource this year, but may not be available next year. In conclusion, the Commission finds and concludes that the utilities have adequately responded to the issues raised by MAREC related to wind energy and that no further action is necessary at this time.

BATTERY STORAGE

Duke Integrated Resource Plans - Battery Storage

According to the Duke IRPs, DEC and DEP are assessing technologies such as battery storage. Duke notes that battery storage costs are expected to decline significantly which may make it a viable option in the long-run to support operational challenges caused by uncontrolled solar penetration. In the short-run, battery storage is expected to be used primarily to support localized distribution based issues.

Duke included battery storage in its screening analysis for the 2016 IRP. As noted in the DEC and DEP IRPs, the ultimate goal of screening is to pass the best alternatives to the integration process. As in past years, the reason for the initial screening analysis is to determine the most viable and cost-effective resources for further evaluation. Duke reviews generation resource alternatives on a technical and economic basis. The resources that are found to be both technically and economically viable are then passed to the detailed analysis process for further analysis.

Based on the results of Duke's screening analysis, battery storage did not advance to the quantitative analysis as a potential supply-side resource option to meet future capacity needs. However, Duke noted in its IRPs that:

> Beginning in 2016, Distributed Energy Resources formed an Energy Storage (ES) team to develop a fifteen year battery storage prediction model and begin the development of battery storage deployment plans for the next five year budget cycle. The ES team will focus their five year plan across multiple jurisdictions, however, the first two areas that will most likely provide deployment sites are Duke Energy Indiana and western NC, Asheville Regional area. Regional battery storage modeling is proceeding to establish battery system sites, use case designs and cost/benefit analysis. Regulatory approvals and cost recovery development will play a key role in the timing of full operational battery system deployment.

DNCP Integrated Resource Plan - Battery Storage

DNCP stated in its IRP that the need for co-located power storage is paramount to address the intermittency and non-dispatchable characteristics of solar generation resources. DNCP noted that energy storage represents a useful capability with regards to the intermittency of many forms of distributed generation, particularly those which rely on solar or wind power. According to DNCP, adoption of storage technologies at the present time has inherent challenges due to cost-effectiveness, reliability, and useful life. As noted in its IRP, DNCP is monitoring recent advances in energy storage technologies, including batteries.

DNCP noted in its IRP that consistent with the 2015 Plan, DNCP included a solar PV facility coupled with a battery as an entry to the dispatchable busbar curve analysis. At a zero capacity factor, the cost of a solar PV/battery facility is approximately $1,000/kW per year higher than a solar PV facility alone. This difference represents the proxy cost of making a solar PV facility dependable and dispatchable. DNCP stated that given the recent advancements in battery technology, it expects batteries will be a viable option for consideration in future integrated resource plans and, as such, deems it appropriate to begin reflecting that option in the busbar curve analysis.

NCSEA Comments - Battery Storage

NCSEA commented that the current IRP process undervalues the benefits that energy storage can provide both as a generation resource as well as to other aspects of the grid. While NCSEA commended the utilities for including some analysis of energy storage in their 2016 IRPs, NCSEA suggested they are still failing to recognize the full value of energy storage to the utilities and to their customers. NCSEA noted that the 2 MW / 8 MWh lithium ion battery storage system is the only type energy storage included in DEC and DEP's economic screening curve analysis model.[1] NCSEA stated that it believes this is a positive addition to Duke's economic screening analysis but it is disappointed that this relatively small and distribution-based application of energy storage was the only technology considered in the economic screening. NCSEA commented that

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[1] See DEC's 2016 IRP, pp. 140-41 and DEP's 2016 IRP, pp. 137-38.

this narrow consideration of energy storage technology and the failure to recognize the grid benefits of storage in the economic screening analysis resulted in all energy storage technologies being excluded from the quantitative analysis component of the IRPs as potential supply-side resource options to meet future capacity needs.

Quoting from a recent report, NCSEA commented that "A crucial component of the value of storage is its ability to support multiple applications, and their value streams, at the same time."[1] These benefits include: integration of renewables; peak load shaving; emergency response and resilience; grid stability; and energy cost reduction such as avoided transmission and distribution costs. NCSEA commented that the Duke IRPs only analyze the generational value of energy storage and do not quantify the value of these additional benefits.

NCSEA commented that if energy storage costs continue to decline at their anticipated rates of 12% - 15% annually,[2] utilities will be doing themselves and their customers a disservice if they continue to undervalue energy storage in their IRPs and therefore their future generation portfolio and grid services.

NCSEA further commented that in light of the fact that the utilities are already working on battery storage predictions and deployment plans, the Commission should direct the utilities to quantify and incorporate the full value stream that energy storage technologies provide in future IRPs and IRP updates. In addition, NCSEA suggested that the Commission should direct the utilities to identify the regulatory barriers or their interpretation of Rule R8-60 that currently prevents them from incorporating the full value of energy storage in their IRPs in a filing before the Commission.

Duke Reply Comments - Battery Storage

Duke commented that regional battery storage modeling is proceeding to establish battery system sites, use case designs and cost/benefit analysis. Regulatory approvals and cost recovery development will play a key role in the timing of full operational battery system development.

Duke noted that traditionally, IRP modeling has been focused on generation needs. According to Duke, energy storage technologies offer generation as a component of system needs; however, the greatest benefits of energy storage are in ancillary services, peak shaving, load shifting, etc. Duke commented that these stacked benefits are very location specific and cannot be generically applied. In addition, the battery technology selected for each application is very specific to the location need, and as a result, the pricing from application to application can vary dramatically.

According to Duke, battery technology as a generator cannot compete with other generation technologies from a price perspective based on the single benefit as a generation need.

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[1] American Council on Renewable Energy & ScottMadden, Inc., Beyond Renewable Integration: The Energy Storage Value Proposition, p. 20 (November 2016).

[2] Id. at p. 32.

As a result, Duke noted that it is working to integrate their planning processes across transmission, distribution, and generation departments to better evaluate the potential for these stacked benefits.

DNCP Reply Comments - Battery Storage

DNCP noted that NCSEA's comments appear to be directed at Duke, however, NCSEA phrases its request in terms of the "utilities" generally. DNCP commented that DNCP already includes the full value of energy storage in its modeling. Therefore, no action is required on this issue with respect to Dominion's 2016 IRP based on NCSEA's comments.

Commission Conclusions - Battery Storage

The Commission recognizes the potential role that battery storage could play in regards to intermittent distributed generation such as solar and wind. However, the Commission also recognizes the current challenges due to cost-effectiveness, reliability, and useful lives of battery technologies. The Commission is of the opinion that evaluations of this technology, as documented in the IRPs, have not been fully developed to a level sufficient to provide guidance as to the role this technology should play going forward. As such, the utilities should provide in future IRPs or IRP updates a more complete and thorough assessment of battery storage technologies including the "full value" as discussed in the NCSEA comments.[1] If the standard technical and economic analyses of generation resources somehow preclude the complete and thorough assessment of battery storage technologies, then a separate discussion of this point should be included in the IRPs.

At a minimum, the utilities should provide pertinent information derived from their active or planned projects that utilize battery technologies. These projects include those identified by Duke that have been in operation since 2011.[2] In addition, Duke should include in its future IRPs or IRP updates, information summarizing the pertinent work and outputs of the Energy Storage Team referenced in its IRPs.[3]

OTHER IRP MATTERS AND CONCLUSIONS

Risk Analysis

The Public Staff commented that DNCP included for the first time in its IRP, a comprehensive risk analysis based on a probabilistic approach that evaluates the risk with respect to future inputs including: natural gas prices, natural gas basis, coal prices, electricity load, CO_2 emission allowance prices, and capital cost for new generation. A probability distribution of future input values for key risk factors is created, as compared to simply assuming a certain future value for key risk factors, as performed in typical modeling of plans. According to the Public Staff, an

[1] NCSEA's Comments, Docket No. E-100, Sub 147 (February 17, 2017), Storage in the Integrated Resource Plans at 5-15.

[2] See DEC's 2016 IRP, p. 139 and DEP's 2016 IRP, p. 136.

[3] See DEC's 2016 IRP, p. 140 and DEP's 2016 IRP, p. 137.

advantage of this approach is that it allows for the quantification of high impact risk factors even though they have a low probability of occurrence. The Public Staff recommended that DEP and DEC develop similar analytical tools to those utilized by DNCP to determine the least cost plan that provides the lowest risk to its customers, while also providing operational and compliance flexibility to the utility.

The Commission recognizes that risk analyses, such as that utilized by DNCP, may better inform the Integrated Resource Planning process. However, the Commission is without sufficient evidence of the value derived from such risk analyses to require DEP and DEC to utilize similar analytical tools in the development of their IRPs.

Roxboro Retrofit Analysis per Docket No. E-2, Sub 1089

On November 16, 2015, the North Carolina Department of Environmental Quality (DEQ) released a draft rule entitled Standards of Performance for Existing Electric Utility Generating Units Under Clean Air Act Section 111(d).[1] If implemented, this draft rule would require heat rate improvements at many fossil-fueled electric generating units in North Carolina.

In its March 28, 2016 Order Granting Application in Part, With Conditions, and Denying Application in Part in Docket No. E-2, Sub 1089 allowing DEP to proceed with construction of a combined cycle plant near Asheville, the Commission directed DEP to conduct an investigation of retrofitting the four coal burning units at its Roxboro plant as proposed in the draft rule, and to include an assessment of the feasibility and cost-effectiveness of this retrofit in its 2016 IRP. DEP provided the results of its investigation in Appendix K of its IRP.

The two potential requirements identified for the Roxboro plant are the installation of an Intelligent Sootblowing (ISB) system and Variable Frequency Drives (VFDs) on boiler fans. DEP explained that ISB uses electronic monitoring to optimize the timing and amount of boiler cleaning, which reduces both wear on the boiler tubing and parasitic load caused by cleaning. The VFDs would reduce the boiler fan parasitic load by replacing the current airflow control that uses damper panels with airflow control that uses electronically regulated fan motors, which have their speed precisely matched to requirements of the boiler.

DEP's economic analysis indicated that including the installation and operation of the ISB and VFD projects beginning in 2020 would result in cost savings of approximately $3 million per project compared to the base case. The payback periods for the ISB and VFD projects would be approximately one and eight years, respectively. Due to the February 9, 2016 U.S. Supreme Court decision staying the federal Clean Power Plan, DEQ has not implemented its draft rule.

The Public Staff recommended that the Commission direct DEP to develop and file with the Commission, within the next six months, a plan to undertake the retrofits to its Roxboro plant identified in Appendix K of its IRP. In addition, the Public Staff recommended that DEP and DEC

[1] Division of Air Quality, DEQ, Section 15A NCAC 02D .2700, Standards of Performance for Existing Electric Utility Generating Units Under Clean Air Act Section 111(d), available online at the following link: http://deq.nc.gov/about/divisions/air-quality/air-quality-rules/draft-rules.

evaluate other efficiency retrofits included in the draft DEQ rule and include an analysis of their potential economic and emissions benefits in their 2017 IRP update.

In reply comments, Duke noted that both DEC and DEP regularly evaluate numerous potential upgrade and retrofit projects at their generation units on an ongoing basis. Requiring DEC and DEP to include such analyses in future IRPs would be burdensome, potentially voluminous, and in Duke's opinion, would not provide meaningful information that is required as part of the IRP process.

The Commission finds that Duke adequately responded to its March 28, 2016 Order.[1] However, the Commission is not persuaded that Duke should be required to develop and file a plan to undertake the Roxboro plant retrofits in future IRPs or IRP updates even if DEP decides to pursue these projects.

In addition, the Commission does not find that documenting internal analyses and decisions relative to individual efficiency retrofit projects is useful in the IRP and, therefore, does not accept the Public Staff's recommendation in this regard.

Cliffside Unit 6 Carbon Neutral Plan

Finding of Fact No. 3 of the 2014 IRP Order stated that "[t]he Cliffside Unit 6 Carbon Neutrality Plan filed by DEC is a reasonable path for DEC's compliance with the carbon emission reduction standards of its air quality permit." The 2014 IRP Order also required DEC to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit. DEC included the required update as Appendix K to its 2016 IRP. The original plan incorporated actions required under DEC's Cliffside Unit 6 air permit, including the implementation of a Greenhouse Gas Reduction Plan. The original plan also required DEC to: (1) retire 800 MW of coal capacity in North Carolina in accordance with the schedule set forth in Table K-1, which was in addition to the retirement of Cliffside Units 1-4; (2) accommodate, to the extent practicable, the installation and operation of future carbon control technology at Cliffside Unit 6; and (3) take additional actions as necessary to make Cliffside Unit 6 carbon neutral by 2018.

The Public Staff noted that the update submitted by DEC in its 2016 IRP is very similar to the one approved in the 2014 IRP Order, and incorporates the same implementation schedule, with updated values for the estimates of conservation, renewable energy, and nuclear uprates. The Public Staff commented that it believes this update represents a reasonable path for DEC's compliance with the carbon emission reduction standards of its air quality permit, and notes that the retirements listed in DEC's IRP, most of which have already taken place, would exceed the Greenhouse Gas Reduction Plan by close to 50%. The Public Staff recommended that the Commission no longer require DEC to include the Cliffside Unit 6 Carbon Neutral Plan in future IRP filings.

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[1] Order Granting Application in Part, With Conditions, and Denying Application in Part, Docket No. E-2, Sub 1089, (March 28, 2016), Item 7, at p. 40.

The Commission concludes that the Cliffside Unit 6 Carbon Neutral Plan filed by DEC is a reasonable path for DEC's compliance with the carbon emission reduction standards of the air quality permit. This conclusion, however, does not constitute Commission approval of individual specific activities or expenditures for any activities shown in the Plan.

Based on the Public Staff's recommendation, the Commission will no longer require DEC to include the Cliffside Unit 6 Carbon Neutral Plan in future IRP filings.

REPS COMPLIANCE PLANS

G.S. 62-133.8 requires all electric power suppliers in North Carolina to meet specified percentages of their retail sales using renewable energy and energy efficiency. One megawatt-hour (MWh) of renewable energy, or its thermal equivalent, equates to one renewable energy certificate (REC), which is used to demonstrate compliance. An electric power supplier may comply with the REPS by generating renewable energy at its own facilities, by purchasing bundled renewable energy from a renewable energy facility, or by buying RECs. Alternatively, a supplier may comply by reducing energy consumption through implementation of EE measures or electricity demand reduction.[1] The electric public utilities (DEP, DEC, and DNCP) may use EE measures to meet up to 25% of their overall requirements in G.S. 62-133.8(b). One MWh of savings from DSM/EE or demand reduction is equivalent to one energy efficiency certificate (EEC), which is a type of REC. All electric power suppliers may obtain RECs from out-of-state sources to satisfy up to 25% of the requirements of G.S. 62-133.8(b) and (c), with the exception of DNCP, which can use out-of-state RECs to meet its entire requirement. The total amount of renewable energy or EECs that must be provided by an electric power supplier for 2016 and 2017 is equal to 6% of its North Carolina retail sales for the preceding year. In 2018, the required amount increases to 10%.

Commission Rule R8-67(b) provides the requirements for REPS Compliance Plans. Electric public utilities must file their plans on or before September 1 of each year, as part of their IRPs, and explain how they will meet the requirements of G.S. 62-133.8(b), (c), (d), (e), and (f). The plans must cover the current year and the next two calendar years, or in this case 2016, 2017, and 2018 (the planning period). An electric power supplier may have its REPS requirements met by a utility compliance aggregator as defined in R8-67(a)(5).

Public Staff Comments - REPS Compliance Plans

The Public Staff commented on DEP, DEC, and DNCP's plans to comply with G.S. 62-133.8(b), (c), and (d), the general[2] and solar energy requirements. The Public Staff also provided consolidated comments on the IOUs' plans to comply with G.S. 62-133.8(e) and (f), the swine and poultry waste set-asides.

[1] "Electricity demand reduction," as used herein, is defined in G.S. 62-133.8(a)(3a).

[2] The overall REPS requirement of G.S. 62-133.8(b), less the requirements of the three set-asides established by G.S. 62-133.8(d)-(f), is frequently referred to as the "general requirement."

Public Staff Comments - DEP's REPS Compliance Plans

According to the Public Staff, DEP has contracted for and banked sufficient resources to meet the REPS requirements of G.S. 62-133.8(b), (c), and (d) for itself and the electric power suppliers for which it is providing REPS compliance services, which includes the Towns of Sharpsburg, Stantonsburg, Black Creek, Lucama, and Winterville (collectively, DEP's Wholesale Customers).[1]

DEP intends to use EE programs to meet 25% of its REPS requirements. Hydroelectric facilities with a capacity of 10 MW or less and energy allocations from the Southeastern Power Administration (SEPA) will be used to meet up to 30% of the general requirement of DEP's Wholesale Customers.[2] Hydroelectric facilities of 10 MW or less will also provide RECs for DEP's retail customers. DEP may also use wind energy, through either REC-only purchases or energy delivered to its customers in North Carolina, to meet the general requirement. A portion of the general requirement for DEP and its Wholesale Customers will be met by executed purchased power agreements and REC-only purchases from landfill gas and biomass power providers, some of which are combined heat and power (CHP) facilities. DEP also plans to use the increased availability of solar energy to meet the general requirement.

To meet the solar set-aside, DEP will obtain RECs from its own solar facilities, its residential solar photovoltaic (PV) program, and other solar PV and solar thermal facilities.[3]

DEP anticipates that its REPS compliance costs will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

DEP files evaluation, measurement, and verification (EM&V) plans for each EE program in the respective program approval docket.

Public Staff Comments - DEC's REPS Compliance Plans

According to the Public Staff, DEC has contracted for or procured sufficient resources to meet the REPS requirements of G.S. 62-133.8(b), (c), and (d) for the planning period, both for itself and for the electric power suppliers for which it is providing REPS compliance services. These suppliers are Rutherford EMC, Blue Ridge EMC, the Town of Dallas, the Town of Forest

[1] In past years, DEP also provided REPS compliance services for the Town of Waynesville; Waynesville took responsibility for its own REPS compliance beginning in 2016.

[2] A hydroelectric facility with a generation capacity in excess of 10 MW is not considered a renewable energy facility under G.S. 62-133.8(a)(7). Under G.S. 62-133.8(c)(2)c, electric membership corporations (EMCs) and municipalities may not meet more than 30% of their REPS requirements with hydroelectric power.

[3] DEP has acquired certificates of public convenience and necessity (CPCNs) for 140.7 MW of solar PV facilities to meet a portion of its REPS compliance obligations. See Order Transferring Certificate of Public Convenience and Necessity, Docket No. E-2, Subs 1054, 1055, and 1056 (Dec. 16, 2014); Order Issuing Certificate of Public Convenience and Necessity, Docket No. E-2, Sub 1063 (Apr. 14, 2015).

City, the City of Concord, the Town of Highlands, and the City of Kings Mountain (collectively, DEC's Wholesale Customers).

DEC intends to use EE programs to meet 25% of its REPS requirements. Hydroelectric facilities with a capacity of 10 MW or less and energy allocations from SEPA will be used to meet up to 30% of the general requirement of DEC's Wholesale Customers. Hydroelectric qualifying facilities of 10 MW or less, together with DEC's Bridgewater hydroelectric facility, will provide RECs for DEC's retail customers. DEC will continue to use wind energy, either through REC-only purchases or energy delivered to its customers in North Carolina, to meet the general requirement. A portion of the general requirement for DEC and its Wholesale Customers will be met through executed purchased power agreements and REC-only purchases from landfill gas and biomass power providers, some of which are CHP facilities. DEC also expects to use solar resources to satisfy the general requirement.

To meet the solar set-aside, DEC will obtain RECs from its self-owned solar PV facilities and from other solar PV and solar thermal facilities.[1]

DEC anticipates that its REPS compliance costs will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

DEC files EM&V plans for each EE program in the respective program approval docket.

Public Staff Comments - DNCP's REPS Compliance Plans

According to the Public Staff, DNCP has contracted for or procured sufficient resources to meet the REPS requirements of G.S. 62-133.8(b), (c), and (d) for the planning period for itself and the Town of Windsor (Windsor), for which it is providing REPS compliance services. While DNCP may use out-of-state RECs to meet all of its compliance requirements, Windsor may only use out-of-state RECs to meet 25% of its compliance requirements. DNCP plans to use EE, purchased out-of-state RECs, and RECs from its own new renewable energy facilities to meet the general REPS requirements of G.S. 62-133.8(b). For Windsor's general REPS requirement, DNCP will use out-of-state wind and hydroelectric RECs, in-state biomass and solar RECs, and Windsor's SEPA allocation. For the solar set-aside, DNCP plans to purchase in-state and out-of-state solar RECs for itself and Windsor. Its total costs are the same as its incremental costs because, unlike DEP and DEC, it plans to purchase only unbundled RECs, rather than RECs that are bundled with renewable electric energy, to meet its REPS requirements.

DNCP anticipates that it will incur research costs in 2016-18 for the continued development of its Microgrid Project. The Microgrid Project consists of wind, solar, and fuel cell energy generation and battery storage at DNCP's Kitty Hawk District Office. The costs in 2016-18 are primarily for operation and maintenance and fuel for the fuel cell electric generation system.

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[1] DEC has acquired CPCNs for 81.4 MW of solar PV facilities for use to meet a portion of its REPS compliance obligations. See Order Amending Certificate of Public Convenience and Necessity, Docket No. E-7, Sub 1101 (June 16, 2016); Order Amending Certificate of Public Convenience and Necessity, Docket No. E-7, Sub 1079 (Dec. 7, 2016); and Order Transferring Certificate of Public Convenience and Necessity, Docket No. E-7, Sub 1098 (May 16, 2016).

DNCP anticipates that the REPS compliance costs for itself and Windsor will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

DNCP files EM&V plans for each EE program in the respective program approval docket.

REPS Compliance Summary Tables

The following tables are compiled from data submitted in DEP, DEC, and DNCP's Plans. Table 1 shows the projected annual MWh sales on which the utilities' REPS obligations are based. It is important to note that the figures shown for each year are the utilities' MWh sales for the preceding year; for instance, the sales for 2016 are MWh sales for calendar year 2015. The totals are presented in this manner because each utility's REPS obligation is determined as a percentage of its MWh sales for the preceding year. The sales amounts include retail sales of wholesale customers for which the utility is providing REPS compliance reporting and services. Table 2 presents a comparison of the projected annual incremental REPS compliance costs with the utilities' annual cost caps.

TABLE 1: MWh Sales for Preceding Year

	Compliance Year		
Electric Power Supplier	**2016**	**2017**	**2018**
DEP	37,572,645	37,409,094	37,637,337
DEC	61,307,708	60,661,074	61,110,288
DNCP	4,377,561	4,331,768	4,366,511
TOTAL	103,257,914	102,401,936	103,114,136

TABLE 2: Comparison of Incremental Costs to the Cost Cap

		DEP	**DEC**	**DNCP**
2016	Incremental Costs	$31,564,879	$22,018,825	$1,051,845
	Cost Cap	$71,367,582	$104,834,112	$6,309,402
	Percent of Cap	44%	21%	17%
2017	Incremental Costs	$47,596,387	$29,197,215	$1,202,736
	Cost Cap	$72,213,282	$105,412,270	$6,269,230
	Percent of Cap	66%	28%	19%
2018	Incremental Costs	$47,756,637	$32,322,034	$1,552,764
	Cost Cap	$73,066,326	$105,968,212	$6,285,600
	Percent of Cap	65%	31%	25%

Swine Waste and Poultry Waste Set-Asides

Beginning in 2012, electric power suppliers were required to meet 0.07% of their retail sales with energy derived from swine waste, pursuant to G.S. 62-133.8(e), and a combined total of 170,000 MWh or equivalent energy derived from poultry waste, pursuant to G.S. 62-133.8(f). The REPS statute provides for increases in these requirements, or set-asides, in later years. The electric power suppliers have had great difficulty in complying with the swine and poultry waste set-asides. From 2012 through 2016, the electric power suppliers have annually filed joint motions in Docket No. E-100, Sub 113, pursuant to G.S. 62-133.8(i)(2), seeking to delay the swine waste energy requirement, and the Commission has granted their requests. In its orders, the Commission has also required the electric power suppliers to file reports describing the state of their compliance with the set-asides and their negotiations with the developers of swine and poultry waste-to-energy projects, initially on a tri-annual basis and now semiannually.[1] These reports are filed under seal in Docket No. E-100, Sub 113A. The Commission further required the electric power suppliers to provide internet-available information to assist the developers of swine and poultry waste-to-energy projects in getting contract approval and interconnecting facilities. Additionally, the Commission has directed the Public Staff to hold periodic stakeholder meetings to facilitate compliance with the swine and poultry waste set-asides.

In their motions for relief under G.S. 62-133.8(i)(2) in 2012 and 2013, the electric power suppliers requested the Commission to delay the poultry waste set-aside requirements as well as the swine waste set-aside requirements, and the Commission granted their requests. In 2014, the electric power suppliers were able to comply with this set-aside as modified by the Commission. Among the reasons why the electric power suppliers did not request a delay in 2014 were the relatively low requirement of 170,000 MWh or equivalent energy in that year and the utilities' ability to bank RECs from earlier years. In addition, the availability of poultry waste RECs in the marketplace had increased by 2014 due to advances in the technology of power generation from poultry waste, the use of thermal energy to meet the set-aside as authorized by Session Law (S.L. 2011-309), and the availability of poultry waste RECs from "cleanfields renewable energy demonstration parks" as authorized by S.L. 2010-195.

In 2015, the statutory poultry waste requirement rose from 170,000 to 700,000 MWh, and the electric power suppliers were unable to comply with this major increase. Consequently, they filed a joint motion seeking again to delay both the swine and poultry waste set-asides. Instead of granting their motion in full, however, the Commission reduced the 2015 statewide aggregate poultry waste requirement to 170,000 MWh and set the requirements for 2016 and 2017 at 700,000 MWh and 900,000 MWh, respectively. The electric power suppliers successfully met the reduced 170,000-MWh requirement for 2015.

In their 2016 joint motion, the electric power suppliers proposed that the 700,000 MWh poultry waste requirement for 2016 be reduced to 170,000 MWh, and that the 2017 requirement be reduced from 900,000 MWh to 700,000 MWh. In its Order issued on October 17, 2016, in Docket No. E-100, Sub 113, the Commission granted their motion.

The State's electric power suppliers have been able to comply only to a very limited extent with the poultry waste set-aside requirement, and not at all with the swine waste requirement. Nevertheless, the REPS statute has served as a stimulus for several important advances in waste-to-energy technology.

First, several hog farms have installed anaerobic digesters at their swine waste lagoons and produced biogas that has been used as fuel to operate small electric generators at these farms.

[1] The smallest electric suppliers were exempted from this requirement.

Electric power suppliers have purchased the electricity produced by these generators – or, alternatively, have purchased the RECs when the electricity was used on the farm where it was generated – and this represented the initial step toward compliance with the swine waste set-aside.

Second, poultry waste has been transported by truck to existing and new generation facilities, where it has been co-fired with wood or other fuels.

Third, large centralized anaerobic digestion plants have been built in areas where numerous hog farms are located. These plants receive swine waste from numerous sources, produce biogas from the waste by the digestion process, and eliminate impurities so that it is eligible to be transported in the natural gas pipeline system. A specified amount of this biogas, which is referred to as "directed biogas" or "renewable natural gas," is injected into a pipeline, and an equivalent amount of natural gas is delivered by the pipeline operator to a gas-fired utility generating plant. These directed biogas facilities were first built in Midwestern states with extensive hog farming activity, but on December 2, 2016, Carbon Cycle Energy, LLC, began construction of a directed biogas facility in Warsaw, North Carolina.

The Public Staff states that the electric power suppliers will likely continue to have difficulty meeting the swine and poultry waste set-asides. As advances in waste processing technology are made, the electric power suppliers may be able to achieve compliance with these requirements in the not too distant future. The supplier best positioned to reach full compliance is DNCP since it can obtain all of its RECs from out-of-state. DNCP has secured enough out-of-state poultry waste RECs for itself and for Windsor for the entire planning period, and in its Compliance Plan expresses confidence that it will also be able to comply with the in-State poultry waste requirement for Windsor. DNCP has obtained sufficient in-state and out-of-state swine waste RECs to meet Windsor's requirements for the entire planning period; it has enough swine waste RECs under contract to meet its own requirements, as well, but it may be unable to comply if its suppliers fail to fulfill their obligations.

As requested by the Commission, the Public Staff held stakeholder meetings on June 23, 2014, and five subsequent occasions. The attendees included farmers, the North Carolina Pork Council, the North Carolina Poultry Federation, waste-to-energy developers, bankers, state environmental regulators, and the electric power suppliers. The meetings allowed the stakeholders to network and voice their concerns to the other parties.

Public Staff Conclusions - REPS Compliance Plans

In summary, the Public Staff concluded that:

1. DEP, DEC, and DNCP should be able to meet their REPS obligations during the planning period, with the exception of the swine and poultry waste set-asides, without nearing or exceeding their cost caps.
2. DEP and DEC would not have been able to meet the swine waste requirement in 2016 had it not been delayed by the Commission, and they met the poultry waste requirement only after the Commission reduced the aggregate statewide requirement to 170,000 MWh. They are uncertain about meeting the requirements in 2017 and 2018.

3. If the 2016 swine waste requirement had not been delayed, DNCP would have met it for the Town of Windsor, but not for itself. DNCP is confident of its ability to comply for the Town of Windsor in 2017 and 2018, and it expects to comply for itself if its suppliers fulfill their obligations.
4. DNCP will meet its own poultry waste requirement for 2016. It will also meet the out-of-state portion of Windsor's requirement, but may not meet the in-state portion. For 2017 and 2018, DNCP expects to meet its own poultry waste requirements, and the out-of-state portion of Windsor's requirements. It is reasonably confident of meeting the in-state portion.
5. DEP, DEC, and DNCP are actively seeking energy and RECs to meet the set-aside requirements for the years in which they expect to fall short of compliance. DEP is no longer purchasing solar and general RECs to meet its general obligation or solar set-aside obligation because it has sufficient solar RECs to comply with both obligations during the planning period.
6. The Commission should approve the 2016 REPS Compliance Plans filed by DEP, DEC and DNCP

<u>Commission Conclusions - REPS Compliance Plans</u>

The Commission concludes that the REPS Compliance Plans filed by the utilities contain the information required by Commission Rule R8-67(b). As such, and based on the recommendation of the Public Staff, the Commission accepts the REPS Compliance Plans filed in this docket.

COMMISSION CLOSING COMMENTS

Integrated Resource Planning is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable electric service. Potential significant regulatory changes, particularly at the federal level, and evolving marketplace conditions create additional challenges for already detailed, technical, and data-driven IRP processes. The Commission finds the IRP processes employed by the utilities to be both compliant with State law and reasonable for planning purposes in the present docket. The Commission recognizes that the IRP process continues to evolve. The comments, findings, conclusions, and Commission directives included in this Order are intended to inform and guide the electric utilities and parties in their ongoing IRP processes and participation.

IT IS, THEREFORE, ORDERED, as follows:

1. That this Order shall be, and is hereby, adopted as part of the Commission's current analysis and plan for the expansion of facilities to meet future requirements for electricity for North Carolina pursuant to G.S. 62-110.1(c).

2. That the IOUs' forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy those loads, and reserve margins are reasonable for planning purposes, and the Commission accepts the IRP Reports as filed in this docket.

3. That the 2016 REPS compliance plans filed by the IOUs are hereby accepted.

4. That the IOUs, in the preparation of future IRPs, shall adhere to the conclusions and directives of the Commission documented in the body of this Order.

5. That pursuant to the Regulatory Conditions imposed in the Merger Order, DEC and DEP shall continue to pursue least-cost Integrated Resource Planning and file separate IRPs until otherwise required or allowed to do so by Commission order, or until a combination of the utilities is approved by the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of June, 2017

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner ToNola D. Brown-Bland did not participate in this decision.

DOCKET NO. E-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016

ORDER ESTABLISHING STANDARD RATES AND CONTRACT TERMS FOR QUALIFYING FACILITIES

HEARD: Tuesday, February 21, 2017, at 9:00 a.m.; Tuesday, April 18, 2017, at 9:30 a.m.; Wednesday, April 19, 2017, at 9:30 a.m.; Thursday, April 20, 2017, and 9:30 a.m.; Friday, April 21, 2017, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, James G. Patterson, and Lyons Gray

APPEARANCES:

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For the Using and Consuming Public:

> Jennifer T. Harrod, Special Deputy Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602
>
> Tim R. Dodge, Lucy E. Edmondson, Heather D. Fennell, and Robert B. Josey, Jr., Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: This is the 2016 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 (FERC) regulations implementing those provisions, which delegated to this Commission certain responsibilities for determining each utility's avoided costs with respect to rates for purchases from qualifying cogenerators and small power production facilities. These proceedings also are held pursuant to G.S. 62-156, which requires this Commission to determine the rates to be paid by electric utilities for power purchased from small power producers as defined in G.S. 62-3(27a).

Section 210 of PURPA and the regulations promulgated pursuant thereto by FERC prescribe the responsibilities of 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 FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring the purchase and sale of electric power by electric utilities to cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration facilities and small power production facilities that meet certain standards can become "qualifying facilities" (QFs), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

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 that 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 jurisdiction, 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 FERC's rules. The Commission implements Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. The instant proceeding is the latest to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate utility-specific avoided cost rates to be paid by the electric utilities to the QFs with which they interconnect. The Commission also has reviewed and made determinations regarding other related matters involving the relationship between the electric utilities and such QFs, such as terms and conditions of service, contractual arrangements, and interconnection charges.

HOUSE BILL 589

This proceeding also is a result of the mandate of G.S. 62-156, which was enacted by the General Assembly in 1979. This statute, as it was effective when the Commission established this proceeding, provided 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 utilities for power purchased from small power producers according to certain standards prescribed therein. The definition of the term "small power producer," for purposes of G.S. 62-156, as in effect when the Commission established this proceeding, was more restrictive than the PURPA definition of that term, in that G.S. 62-3(27a) included only hydroelectric facilities of 80 megawatts (MW) or less, thus excluding power producers using other types of renewable resources. While this matter was pending before the Commission, the General Assembly enacted House Bill 589, amending G.S. 62-3(27a) and G.S. 62-156, and enacting G.S. 62-110.8, which establishes a program for the competitive procurement of energy and capacity from renewable energy facilities.

PROCEDURAL BACKGROUND

On June 22, 2016, the Commission issued an Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Hearing. Pursuant to that Order, Duke Energy Carolinas, LLC (DEC); Duke Energy Progress, LLC (DEP); Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (Dominion); Western Carolina University (WCU); and New River Power and Light Company (New River) were made parties to these proceedings.

The following parties timely filed petitions to intervene that were granted: North Carolina Sustainable Energy Association (NCSEA); Public Works Commission of the City of Fayetteville;

Carolina Utility Customers Association, Inc.; Carolina Industrial Groups for Fair Utility Rates I, II, and III; Southern Alliance for Clean Energy (SACE); Strata Solar, LLC; North Carolina Pork Council; NTE Carolinas Solar, LLC; Cypress Creek Renewables, LLC (Cypress Creek); O_2 EMC, LLC; and North Carolina Electric Membership Corporation (NCEMC). Participation of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). On April 11, 2017, the North Carolina Attorney General's Office gave notice of intervention pursuant to G.S. 62-20.

On November 15, 2016, DEC and DEP (Duke) and Dominion (collectively, the Utilities) each filed their initial comments, statements, and exhibits. On November 28, 2016, WCU and New River filed proposed avoided cost rates.

On December 20, 2016, NCSEA filed a Motion to Strike as irrelevant certain materials in the Utilities' initial comments, which was denied by Commission order issued on January 18, 2017.

On December 22, 2016, the Public Staff filed a Motion for Amended Procedural Schedule. Similar to Duke's request included in its initial comments, the Public Staff requested an evidentiary hearing in this proceeding, and requested modifications to the procedural schedule. On December 30, 2016, the Commission issued an Order Scheduling Evidentiary Hearing and Amending Procedural Schedule, granting Duke and the Public Staff's requested evidentiary hearing and modifying the procedural schedule in this proceeding.

On January 17, 2017, DEC and DEP filed confidential avoided cost information.

On or after February 13, 2017, 900+ consumer statements of position were filed in this docket.

On or before February 15, 2017, all electric utility companies filed Affidavits of Publication of Notice of Public Hearing as required by the Commission's June 22, 2016 Order. The public hearing was held on February 21, 2017, as scheduled. Twelve witnesses testified at the public hearing.

On February 21, 2017, Dominion filed the direct testimony of J. Scott Gaskill and Bruce Petrie, and Duke filed the testimony and/or exhibits of Lloyd Yates, Kendal Bowman, Glen Snider, John Holeman, III, and Gary Freeman.

On March 28, 2017, NCSEA filed the testimony and exhibits of Carson Harkrader, Ben Johnson, and Kurt Strunk; Cypress Creek filed the testimony of Patrick McConnell; and SACE filed the testimony and exhibits of Thomas Vitolo, Ph.D.; and the Public Staff filed the testimony and exhibits of John Hinton, Jay Lucas, and Dustin Metz. Also on March 28, 2017, NCEMC filed initial comments.

On April 10, 2017, Dominion filed the rebuttal testimony of witnesses Gaskill and Petrie, and Duke filed the rebuttal testimony of witnesses Bowman, Snider, Holeman, and Freeman.

On August 8, 2017, Duke and Dominion jointly filed a motion, requesting that the Commission take into consideration Session Law 2017-192 (S.L. 2017-192 or HB 589) as additional authority in deciding the legal and policy issues in this proceeding. The Commission concludes that this motion should be granted. As reflected in the discussion and conclusions in this order, the Commission considered the authority enacted by S.L. 2017-192 in determining the issues in this proceeding.

In addition to the foregoing, there were other motions, orders, and filings not specifically mentioned which are matters of record.

Based on the entire record in this proceeding, the Commission makes the following

FINDINGS OF FACT

1. The economic and regulatory circumstances facing QFs and electric public utilities in North Carolina have changed since the Commission's last biennial review of standard avoided costs rates.

2. For nonrenewable QFs, it is appropriate for DEC, DEP, and Dominion to be required 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 MW or less capacity. The standard levelized rate option of ten years should include a condition making the contracts under that option 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.

3. It is appropriate for DEC, DEP, and Dominion 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.

4. Dominion 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 (Sub 106 Order), except as modified by this order.

5. For nonrenewable QFs, when calculating avoided capacity rates using the peaker method, it is appropriate to require a payment for capacity in years of a utility's integrated resource planning (IRP) forecast period when a capacity need is demonstrated during that period; however, providing a levelized capacity payment over the term of the contract is a reasonable means of implementing this capacity payment.

6. It is appropriate for the utilities to continue to evaluate the capacity benefits of QF generation and to make other changes as needed to accurately reflect the avoided capacity benefits provided by QF generation of all resource types over the short and long run.

7. The availability of a combustion turbine (CT) is not determinative for purposes of calculating a Performance Adjustment Factor (PAF), because the fixed costs of a peaking unit under the peaker methodology employed by the Commission are a proxy for the capacity-related portion of the fixed costs of any avoided generating unit.

8. It is appropriate to require DEC, DEP, and Dominion to utilize a 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 by further order of the Commission or in accordance with the stipulation filed by DEC, DEP, and the NC Hydro Group and the Commission's December 31, 2014, Order in Docket No. E-100, Sub 140 (Sub 140).

9. DEC and DEP's proposed seasonal allocation weightings of 80% for winter and 20% for summer are appropriate for use in weighting capacity value between winter and summer, and should be used in calculating DEC and DEP's avoided capacity rates in this proceeding.

10. It is not appropriate for DEC and DEP to reset energy prices under the standard offer contract every two years at this time.

11. It is appropriate to require DEC and DEP to recalculate their avoided energy rates using forward natural gas prices for no more than eight years before using fundamental forecast data for the remainder of the planning period.

12. The input assumptions used by Dominion for the purpose of determining its proposed avoided energy rates, including the avoided costs related to fuel hedging activities, are appropriate for use in this proceeding.

13. An imminent violation of a North American Electric Reliability Corporation (NERC) BAL Standard is a system emergency, as defined in 18 CFR 292.101(b)(4); therefore, it is appropriate for DEC, DEP, and Dominion to curtail PURPA QFs when a NERC BAL Standard violation is imminent.

14. It is appropriate for DEC and DEP to amend their standard offer contract to incorporate the imminent violation of a NERC BAL Standard into the system emergency provision.

15. It is appropriate for DEC, DEP, and Dominion to file procedures with the Commission stating how they would curtail QFs on a nondiscriminatory basis when there is a system emergency.

16. It is appropriate for Dominion to make locational energy pricing adjustments to its avoided energy rates accounting for the locational value of distributed generation located in its North Carolina service area.

17. There is power backflow on substations in Dominion's North Carolina service territory from solar generation on the distribution grid such that avoided line loss benefits associated with distributed generation have been reduced or negated.

18. It is appropriate for Dominion to eliminate the line loss adder of 3% from its standard offer avoided cost payments to solar QFs on its distribution network.

19. It is appropriate for Duke to continue to include the line loss adjustments in its avoided energy calculations and to study the effects of distributed generation on power flows on its electric systems to determine if there is sufficient power backflow at its substations to justify eliminating the line loss adjustment from their standard offer avoided cost calculations filed in the next avoided cost proceeding.

20. It is appropriate to require DEC, DEP, and Dominion to propose avoided cost rates in the next biennial avoided cost proceeding that reflect consideration of factors such as the availability of capacity, the QF's dispatchability and reliability, and the value of the QFs' energy and capacity, without regard to the technology the QF uses to generate electricity.

21. It is appropriate to require WCU and New River to offer to all QFs contracting to sell one 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. The changes the Commission approves herein to DEC's proposed ten-year avoided capacity rates should be reflected in the long-term avoided capacity rates that WCU and New River file in compliance with this Order.

22. It is appropriate to add a fourth requirement to the current Commission standard for the establishment of a legally enforceable obligation (LEO) for QFs. Therefore, a QF may establish a LEO when it has (1) self-certified with FERC as a QF, (2) made a commitment to sell its output to a utility under PURPA using the approved Notice of Commitment Form (NoC), (3) filed a report of proposed construction (RPC) or received a Certificate of Public Convenience and Necessity (CPCN) for the construction of the facility, and (4) submitted a completed interconnection request pursuant to the North Carolina Interconnection Procedures (NCIP). For a QF larger than one MW that has been designated as an A or B project in the interconnection queue at the time of its interconnection request, the date on which the commitment to sell is established shall be the earlier of (i) 105 days after the submission of the interconnection request, or (ii) upon the receipt of the system impact study from the public utility. For a QF larger than one MW that has not been designated as an A or B project in the interconnection queue at the time of its interconnection request, the date of the commitment to sell shall be the earlier of (i) 105 days after the project is first designated as an A or B project, or (ii) upon the receipt of the system impact study from the

public utility. In either case, where the QF has or has not been designated an A or B project, the 105-day period as part of establishing a LEO will remain in effect until the Commission issues a final order in Docket No. E-100, Sub 101. If, by final order issued in that docket, the Commission alters the NCIP's 105 day-deadline for providing a QF with the results of the utility's system impact study, that altered deadline shall be substituted for the 105-day standard approved in this order. If, prior to the expiration of the 105 days or the substituted date from Docket No. E-100 Sub 101, the utility anticipates being unable to deliver the results of the system impact study to the QF, the utility may petition the Commission for an extension of that deadline and a delay in the establishment of the QF's LEO. In the proceeding on such a petition, the utility shall bear the burden of proof to justify any requested extension and delay, and the length thereof. The Commission shall address such petitions on an expedited basis and determine the appropriate deadline extension and LEO date on a case-by-case basis.

23. For any QF that withdraws its commitment to sell, it is appropriate to limit such a QF to "as available" rates for the two years following the withdrawal of the commitment.

24. It is appropriate to require DEC, DEP, and Dominion to modify the NoC to reflect the additional requirement for QFs larger than one MW, and to explain the consequences of withdrawal of a NoC.

25. It is appropriate for the Public Staff to convene a working group that includes DEC, DEP, Dominion, and other interested parties, with the goal of developing consensus around proposed revisions to the notice of commitment form, making further refinements to the LEO standard, and other procedures for streamlining the negotiated PPA process.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 1

The evidence for this finding of fact is found in the testimony of Duke witnesses Yates, Bowman, Snider, and Holeman; Dominion witness Gaskill; the Public Staff witnesses Hinton and Metz; and NCSEA witnesses Johnson and Harkrader.

Summary of the Evidence

The parties provided extensive testimony and exhibits regarding the economic and regulatory conditions facing QFs and utilities in North Carolina. Duke witness Yates testified that North Carolina is now at a critical crossroads regarding the integration, development, and customer costs of renewable generation, specifically QF solar generation, under PURPA. He testified that, as of 2016, 60% of all installed PURPA solar projects in the United States are located in North Carolina, attributing this to North Carolina having "significantly encouraged" solar development under PURPA compared to other states. Witness Yates further testified that the existing policies that led to this growth in PURPA solar have also created a distorted solar marketplace resulting in artificially high costs being passed on to North Carolina residents, businesses, and industries, while potentially degrading operation of Duke's electric systems. He supported these arguments with data and by making reference to the testimony of other Duke witnesses. He concluded his testimony by stating that Duke believes that its proposed changes are reasonable and necessary to ensure that its customers and the State's energy systems prosper as Duke continues to add renewable generation resources, and that Duke looks forward to continued collaboration with interested parties to consider improvements that are critical to North Carolina's sustainable energy future.

Duke witness Bowman testified regarding the PURPA regulatory scheme. She emphasized that Congress assigned implementation of PURPA to state commissions that are best suited to consider and balance PURPA's goals with the economic and regulatory circumstances that vary from state-to-state and utility-to-utility. She further testified that North Carolina has evolved its implementation of PURPA over time as economic and regulatory circumstances have changed, including adjusting the standard offer eligibility threshold, as well as the technologies eligible for 10- and 15-year standard offer contracts. Witness Bowman testified that the Commission has balanced the interests of QFs, the utilities, and customers through the State's PURPA standard offer implementation, recognizing that the overpayment risk to customers historically has been relatively small as QFs entitled to long-term rates were of limited number and size. However, she further testified that, since 2005, the State's implementation of PURPA has remained relatively unchanged. Therefore, witness Bowman argued that changing economic and regulatory circumstances – specifically the "surging" growth of utility-scale QF solar in North Carolina – is now driving the need for comprehensive review of the Commission's PURPA policies.

In support of her argument, witness Bowman highlighted the growth in utility-scale solar over the past few years, with approximately 1,100 MW of third-party QF solar now installed on DEP's system and 500 MW installed on DEC's system. She also noted that an estimated 4,900 MW of additional third-party QF solar capacity (approximately 3,800 MW in DEP and 1,100 MW in DEC) are already in development and are requesting to interconnect and sell power to DEC or DEP. Witness Bowman also testified that PURPA is now the predominant driver of the continued development of solar QF projects in North Carolina, as the State's Renewable Energy Tax Credit has expired and as DEP and DEC have achieved long-term compliance with North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) requirements. She also noted that the additional solar renewable energy certificates (RECs) made available from solar-powered QFs are being used to meet the future requirements of the general REPS requirements rather than the solar set-aside requirements.

Witness Bowman continued her testimony by addressing why North Carolina is experiencing greater PURPA growth than other states. She testified that the Commission's historic PURPA polices, including the threshold to establish a LEO and the long terms for standard contracts offered to QFs under 5-MW in generation capacity are more favorable than other jurisdictions, and have made North Carolina the fastest growing solar development marketplace in the Southeast and a leader in distributed utility-scale solar deployment nationally. She observed that Section 210(m) of PURPA, as enacted by the EPAct, provides for termination of the PURPA "must-purchase" obligation for utilities in organized markets and regional transmission organizations where QFs have non-discriminatory access to competitive wholesale energy and capacity markets. Witness Bowman also stated that other states in the Southeast have not adopted PURPA implementation policies as favorable to QFs as North Carolina's policies. Additionally, she testified that other jurisdictions around the country with significant PURPA development have recently taken steps to adjust their PURPA standard offer implementation, largely in response to significant growth of intermittent wind and solar QF generation that was increasingly causing over-supply and growing operational challenges. She argued that continuing the State's current PURPA policies may cause even greater interest in selling QF solar power under the current

PURPA regime and significantly increase the overpayment risk for customers as QFs are no longer of limited size and number. Finally, Witness Bowman testified that in assessing the public interest under PURPA, the Commission should consider two broader purposes of the State's energy policies under the Public Utilities Act: 1) to assure the delivery of reliable and least cost electricity to citizens and businesses of the State, and 2) to integrate a diverse and cost-effective mix of renewables and demand side resources to reliably serve customers.

Duke witness Snider testified that Duke's estimated long-term fixed purchase power obligation for the 1,600 MW of installed solar QFs as of year-end 2016 is approximately $2.9 billion dollars over the remaining 12-14 year terms of these agreements. He also testified that if these contracts were valued at the avoided cost rates Duke proposed in this proceeding, they would have a value of only $1.9 billion, resulting in what he views as a potential long-term "overpayment" of approximately $1.0 billion. Witness Snider also testified that it is critical for the Commission to appreciate that customers' current financial obligation and exposure to "overpayment" risk could increase significantly in the future, as approximately an additional 1,100 MW of solar QFs under 5 MW have established LEOs under the Commission's current policy..

Duke Witness Holeman testified to his recent experience as system operator and the growing operational concerns, reliability risks, and North American Electric Reliability Corporation (NERC) compliance challenges of integrating significant additional QF solar into the DEP and DEC Balancing Authority Areas (BAAs). He testified that DEP and DEC are independent Balancing Authorities (BAs) and must independently balance generation resources, unscheduled QF energy injections, and load demand in real-time, which is essential to providing reliable firm native load service, maintaining compliance with mandatory reliability standards, and achieving reliable bulk electric system operations across the Eastern Interconnection. Witness Holeman described Duke's growing operational experience over the past 18 months with growing levels of installed PURPA solar, and highlighted the potential for future challenges to reliable system operations, based on significant additional PURPA solar proposed to be installed over the next few years.

Witness Holeman further testified that solar QFs are making "unscheduled" and "unconstrained" energy injections into Duke's electric systems, outside of the Security Constrained Unit Commitment process, such that balancing the system is becoming increasingly volatile due to large and uncertain swings in the unscheduled and unconstrained solar QF energy injections. He testified that growing injections of unscheduled QF solar is requiring DEP to increasingly manage the Security Constrained Unit Commitment of its network generating resources at their lowest reliable operating limit (LROL), which Duke defines as the minimum operating level necessary to reliably provide frequency regulation and load-following resource availability to meet the evening peak as well as the next morning's peak demands. Witness Holeman presented figures and testimony analyzing how solar QFs' non-summer energy production between 10 a.m. and 3 p.m. is not coincident with DEP's and DEC's load shape and is increasingly requiring steep down-ramping of network resources, as well as causing operationally excess energy to meet the LROL, during the late morning. After solar production peaks during the mid-day and then declines in the afternoon, DEP is increasingly experiencing deficit energy situations requiring steep ramping up of network resources to meet evening peak loads. Witness Holeman also testified that the variability, volatility, and intermittency of QF solar energy production is causing DEP system operators to have limited operational situational awareness over the performance of these generators intra-day (caused by intermittency of solar production) and day-ahead (caused by variability of solar production) and is also requiring increasingly steep ramping of the BA's load-following network resources.

Witness Holeman also testified that DEP is now experiencing "operationally excess energy" with some regularity during an increasing number of days and hours throughout the year, including 105 hours in 2016 and 71 hours on 19 days during the first month and a half of 2017. Witness Holeman also forecasted that continued growth in installed QF solar capacity will significantly increase operationally excess energy in the DEP BA to 370 gigawatt hours per year by 2022. Witness Holeman also testified how the growing levels of operationally excess energy caused by the increasing levels of solar QFs will continue to put the DEP BA at risk of violating the mandatory NERC BAL reliability standards.

Dominion witness Gaskill testified to the significant influx of solar QF development that has occurred in Dominion's North Carolina service area since the Commission's most recent biennial avoided cost proceeding. Witness Gaskill testified that when the previous avoided cost case commenced in February 2014, Dominion had only seven PPAs executed in its North Carolina service area for approximately 58 MW of solar QF capacity, and only one of those PPAs concerned a project that was operational. In contrast, he testified that, as of February 1, 2017, Dominion had 72 effective PPAs for approximately 500 MW of solar QF capacity in North Carolina, of which, approximately 350 MW is operating and 150 MW is in development. Witness Gaskill presented data showing that, from an interconnection perspective, there was approximately 1,000 MW of capacity in Dominion's North Carolina distribution queue, and another 1,800 MW in the PJM queue for transmission level interconnections. He also emphasized that the vast majority of QFs established LEOs qualifying for the standard contract or negotiated avoided cost rates under the 2014 biennial proceeding.

Witness Gaskill also testified that, because the average on-peak load of its North Carolina service area during 2015 was approximately 518 MW, the amount of North Carolina distributed solar generation that is operational, under construction, or under contract equals or exceeds Dominion's average on-peak load requirements. He noted that the total distributed solar capacity planned for Dominion's North Carolina system rises to approximately 680 MW when QFs that have established LEOs, but not executed PPAs, are included, which exceeds the average on-peak load requirements by approximately 160 MW. He noted further that when the capacity of projects with CPCNs, but no LEOs, is accounted for, the total planned capacity increases dramatically to over 1,500 MW, almost three times Dominion's on-peak load requirements. Witness Gaskill also noted that Dominion's service area anticipates little load growth.

Witness Gaskill testified that three areas of avoided costs are impacted when distributed solar generation exceeds load: distribution line losses are not avoided; locational marginal prices (LMPs) are lower; and incremental QF generation cannot defer or avoid future capacity needs because there is no further load to offset. He testified that the modifications to the standard offer rates and terms Dominion has proposed are intended to address these impacts of the influx of distributed solar development, while remaining consistent with the requirements of PURPA and FERC's rules. He stated that while the Commission addressed similar proposals to some of these modifications in previous avoided cost proceedings, in light of the significant growth in solar QF development that has occurred since the 2014 biennial proceeding, it is imperative that the Commission reconsider these issues on a prospective basis for new solar QFs, or Dominion and its customers will be forced to overpay for new QF output in contravention of PURPA's intent. He noted the Commission's January 18, 2017 order in this docket, stating that the Commission has always established avoided cost rates and implemented PURPA in light of the then prevailing economic conditions facing public utilities and QFs and whether changed conditions justify changes in avoided cost rates and/or PURPA implementation.

Public Staff witness Hinton testified to the level of solar QF development over the past five years in North Carolina, totaling approximately 2,000 MW installed and approximately 7,000 MW of additional solar QFs proposing to interconnect and sell power to the Utilities. He also testified that this significant growth of facilities from which the utilities are obligated to purchase energy and capacity has increased the risk of potential overpayments by ratepayers. He suggested that the sheer volume of QF projects currently being developed in North Carolina calls into question FERC's premise in Order No. 69[1] that future over-estimations and under-estimations of fixed long-term avoided costs would "balance out" over time. He also testified how this higher penetration of solar QF resources is posing operational and technical challenges for the utilities in meeting their obligation to provide safe, reliable, and economic service to ratepayers. Witness Hinton further testified that the pace of QF solar development is now exceeding load growth experienced by the utilities.

NCSEA witness Johnson agreed that North Carolina has been experiencing significant growth in solar production and testified that this growth is both "substantial and more rapid than the relatively leisurely pace at which solar activity is occurring in nearby" southeastern states. In addition, NCSEA witness Harkrader agreed with the Utilities; that "over the past few years North Carolina has been an undisputed leader in terms of installed solar generating capacity." Witness Johnson further testified that the Commission should not adopt less favorable PURPA terms in order to slow the growth of solar. In support of this recommendation, he testified that growth in solar production has long been the goal of public policy makers in North Carolina and elsewhere. Further, witness Johnson testified that policies such as renewable portfolio standards, and tax incentives were adopted to break the "vicious cycle" of the comparatively high life cycle costs of solar electric generation versus traditional energy sources such as oil and coal. He then testified that, in North Carolina, the solar industry is starting to break this vicious cycle and that it "would be a mistake to slam on the breaks just as commercial mass scale is beginning to be achieved." Witness Johnson acknowledged that the challenges faced by the Utilities are real and testified that careful investigation should be conducted and an appropriate policy response should be developed to ensure that these challenges do not become more serious. However, he further testified, that these challenges should not be reason to slow the growth of solar. In his view, the Utilities have not recognized the benefits to society from the rapid growth in solar energy production and instead have focused their testimony in this proceeding "almost entirely" on the technical difficulties and operational challenges they are facing as a result of the growth in solar energy production. Witness Johnson concluded this portion of his testimony by stating that if the Commission adopts the Utilities' proposals, solar expansion will occur at a more leisurely pace, like what is occurring in

[1] See Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978, 45 Fed. Reg. 12, 214 at 12, 224 (Feb. 1980) (Order No. 69).

Louisiana or Mississippi, and it will decrease the opportunity for solar energy production to break the vicious cycle of high costs and little experience.

In his post-hearing brief, the Attorney General addressed many of the Utilities' specific proposals to change the Commission's PURPA implementation. The Attorney General argues that the Utilities essentially admitted that their goal in proposing changes to PURPA implementation is to rein in what they view as "'unconstrained growth in solar generation.'" The Attorney General emphasizes the federal and state law requirement to encourage small power producers to support the goals of promoting energy conservation, more efficient use of energy resources, and energy independence of the United States. The Attorney General further argues that the many of the benefits to consumers from the increase in alternative energy available in North Carolina due to PURPA and other policies are not and cannot be captured in avoided cost calculations, for example, national security, environmental benefits, health benefits, competition and lower prices, and economic benefits. In support of his argument, the Attorney General notes that the testimony of the public witnesses at the February 21 public hearing and the 900+ consumer statements filed in this docket have been "robust and uniformly in support of renewable energy." As reflected in the other sections of this order, the Attorney General then argues that the Commission should maintain the status quo on its PURPA implementation because the Utilities' proposals are either unsupported by the facts or contrary to the law.

Discussion and Conclusions

The Commission takes notice that subsequent to the close of proceedings in this docket, the North Carolina General Assembly enacted and the Governor signed House Bill 589. H.B. 589, N.C. Gen. Assem., 2017 Reg. Sess., S.L. 2017-192 (N.C. 2017). With respect to renewable QFs, this legislation resolved a number of the significant issues in this docket, and the Commission therefore need not address them. However, the legislation fails to address nonrenewable QFs such as combined heat and power QFs. Therefore, the Commission must address such issues for the nonrenewable QFs. As to these nonrenewable QFs, however, the Commission resolves the issues not addressed by HB 589 consistent with that legislation.

There is substantial evidence in this proceeding as to the amount and pace of the development of QFs, and in particular solar-powered QFs selling energy and capacity to the Utilities under the standard offer contract. The Utilities' witnesses' testimony on this issue is largely undisputed, and is supported by the independent and consistent testimony of the Public Staff's witnesses. Further, NCSEA's witnesses agree with the Utilities' fundamental argument that the development of QFs that has occurred in North Carolina is significant. The Commission finds highly persuasive the Duke witnesses' testimony that 60% of all installed PURPA solar projects in the United States are located in North Carolina, many of these QFs being sized at or just below the Commission-established 5-MW threshold for eligibility for the standard offer contract. The Commission also agrees with Duke witness Yates: North Carolina is at a critical crossroads regarding the integration, development, and customer costs of renewable generation, and specifically with regard to QFs powered by solar energy. Further, the Commission agrees with the Utilities' witnesses and Public Staff witness Hinton that the implications of the pace and level of QF development continuing unabated poses serious risk of overpayment by utility ratepayers and operational soundness of utility electric systems, and, ultimately, calls into question the State's continued compliance with PURPA's requirements. Therefore, based upon the foregoing and the entire record in this proceeding, the Commission finds that economic and regulatory circumstances facing QFs and utilities in North Carolina have changed since the Commission's last biennial review of standard avoided costs rates.

Having found that the record evidence demonstrates that the circumstances facing QFs and utilities in North Carolina have changed since the Commission's last biennial proceeding, the contested issues are whether this evidence justifies the Commission establishing new avoided cost rates and/or altering the Commission's implementation of PURPA. In the other sections of this order, the Commission will consider these contested issues in light of the evidence on the inputs included in the avoided cost rate methodology and the discrete aspects of the Commission's PURPA implementation. In the remainder of this section, the Commission addresses the broader question of PURPA's requirements and whether the evidence in this proceeding justifies establishing new avoided cost rates and changing the Commission's PURPA implementation. The Commission also agrees with witness Johnson, that in implementing PURPA, the Commission should not "slam on the brakes" in establishing rules for the development of QF resources. Rather, as the Commission's policies have resulted in North Carolina cresting the hill, it now is appropriate to moderately ease off on the regulatory accelerator and depend in part on momentum created so as to moderate the financial impact on electric rate payers. Therefore, the Commission agrees with some recommended changes but not with others.

The Commission finds persuasive the testimony of Duke witnesses Yates and Bowman and Dominion witness Gaskill regarding the causal link between the amount of solar-powered QF development activity, on the one hand, and the Commission's PURPA implementation and Commission-established avoided cost rates, on the other. The Commission agrees with witness Yates that existing regulatory and legislative policies have created a "distorted marketplace" for solar projects and that this results in artificially high costs being passed on to North Carolina ratepayers. The Commission further agrees with witness Yates that the increasing amount of solar-powered QFs interconnected to Duke's electric systems is inhibiting the Companies' ability to fulfil its public service mission and statutory obligation to provide safe and reliable energy to its customers at reasonable rates.

The Commission also finds persuasive the testimony of witness Bowman that the generating capacity of solar-powered generating facilities installed on Duke's electric systems has increased from 125 MWs in 2012 to 1,600 MWs in 2016. The Commission is mindful of the policy declarations in G.S. 62-2(a), in particular, the policy to promote adequate, reliable, and economical utility service to all the citizens and residents of the State, which witness Bowman testified should be considered in assessing the public interest under PURPA. The Commission agrees with witness Bowman that there is a causal link between avoided cost rates and PURPA implementation, on the one hand, and the level of solar-powered QF development in the state, on the other. For example, she testified that, despite the expiration of the North Carolina renewable energy tax credit and the fact that the Duke utilities have enough solar RECs to meet the solar set-aside requirements beyond 2030, the development of solar-powered QFs with a generating capacity between four and five MW continues. Further, as cited by witness Bowman, two policy developments differentiate North Carolina from other states: the modifications to PURPA enacted by the EPAct, which relieved a number of utilities across the country from PURPA's "must purchase" obligation, and that other states' PURPA policies are not as favorable to QFs as North Carolina's policies. Her testimony is made more compelling in light of the independent, but consistent, testimony of the Dominion witnesses and the Public Staff witnesses. Although NCSEA witness Johnson draws different conclusions from this evidence, he agrees with the basic premise that North Carolina's PURPA policies have contributed to QF development at a more rapid pace than in other states.

Finally, in this section the Commission addresses what changes to the Commission-established avoided cost rates and PURPA implementation are appropriate in light of the foregoing evidence and the legal framework for avoided cost set out in PURPA, North Carolina law, and Commission precedent. First, as testified to by Duke witness Bowman, under the cooperative federalism program established in Section 210 of PURPA, this Commission is tasked with balancing PURPA's goals with the economic and regulatory circumstances facing QFs and utilities in North Carolina. This Commission is guided by FERC's regulations promulgated under PURPA, but afforded "great latitude" in determining North Carolina's PURPA policies and establishing avoided cost rates. See Order No. 69 at 12,230-12,231. Second, as testified to by Public Staff witness Hinton, PURPA and the FERC rules implementing PURPA require each electric utility to purchase electricity produced by QFs at the utility's "incremental cost of alternative energy," commonly called "avoided costs." These rates must be just and reasonable to the electric consumers, in the public interest, and non-discriminatory to the QFs. Properly established, the avoided cost rates make the purchasing utility indifferent to purchasing electric output from a QF or from another source, including the utility building and owning its own generation facility. Third, as the witnesses in this proceeding have testified, PURPA requires the encouragement of QF development. Finally, this Commission is constrained to implement PURPA and establish avoided cost rates consistent with state law, including the policy declarations in G.S. 62-2(a) and the more specific directives in G.S. 62-156. Thus, the Commission's task in this proceeding is to resolve the tension existing within this legal framework by establishing just and reasonable avoided cost rates and making adjustments to the Commission's PURPA implementation where, in the Commission's discretion, such adjustments are justified by the evidence.

Since the first biennial avoided cost proceeding in 1981 (Docket No. E-100, Sub 36) the Commission has used its discretion to implement PURPA and establish avoided cost rates based upon the economic and regulatory circumstances existing at the time. The Commission has, for example, varied the length of standard offer contract that utilities are required to offer, the eligibility threshold for the standard offer contract based on QF generating capacity, and the availability of the standard offer contract based upon QF fuel sources. However, since the Commission conducted the 2004 biennial proceeding (Docket No. E-100, Sub 100) the Commission's implementation of PURPA and the methodology for establishing avoided cost rates have remained relatively unchanged.

Most recently, in the 2014 biennial proceeding, the Commission considered again the economic and regulatory circumstances facing QFs and utilities in North Carolina. In that two-phase proceeding, the Commission first considered changes to the method used to calculate avoided cost payments and whether the methods historically relied upon by the Commission to determine avoided cost capture the full avoided cost. See Order Setting Avoided Cost Input Parameters, E-100, Sub 140, issued December 14, 2014 (Order on Inputs). In phase one, the Commission recognized that implementing PURPA and establishing avoided cost rates requires balancing the costs, benefits, and risks to all parties and utility customers, and that "regulatory continuity and certainty play a role in the development and implementation of sound utility regulatory policy." Id. at 21-22. The Commission concluded that there was insufficient evidence that the current framework fails to comply with the requirements of PURPA or otherwise disadvantages QFs, and that, absent such evidence that would justify altering the Commission's earlier decisions, it was inadvisable to introduce regulatory uncertainty by changing that framework. Id. In the second phase of that proceeding, the Commission considered and established avoided cost rates consistent with the inputs developed in phase one. See Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 140, December 17, 2015 (Phase II Order).

Unlike the 2014 biennial proceeding, in this proceeding the Commission has found substantial evidence that the economic and regulatory circumstances facing QFs and utilities in North Carolina have changed. For the foregoing reasons, and as detailed in the other sections of this order, the Commission concludes that this evidence demonstrates that it is now appropriate to make refinements to the Commission's implementation of PURPA and adjustments in the Commission-approved avoided cost rates. Consistent with the Commission's approach in past avoided cost proceedings, where the evidence fails to justify changing the avoided cost inputs or the Commission's PURPA implementation, the Commission will avoid introducing regulatory uncertainty; however, where the evidence supports changes, the Commission will use its discretion to require appropriate changes.

Finally, as an agency created by statute, the Commission is mindful that it exercises legislative functions and authority delegated to it by statute. See State ex. rel. Util. Com. v. Edmisten, 291 N.C. 451, 232 S.E.2d 184 (1977). On July 27, 2017, the Governor signed House Bill 589 (S.L. 2017-192 or HB 589) into law. Session Law 2017-192 addresses contested issues in this proceeding in three ways: 1) by amending G.S. 62-156(b) to provide direction to the Commission on implementation of the PURPA standard contract offering; 2) by enacting G.S. 62-156(c) by providing direction to the Commission on implementation of PURPA negotiated contracts; and 3) by enacting G.S. 62-110.8 which establishes a requirement that DEC and DEP file with the Commission a program for the competitive procurement of energy and capacity from renewable energy facilities. More specifically, the amendments enacted in HB 589 broadened the definition of "small power producer" to include QFs that use renewable resources as a fuel source but not cogeneration facilities. See G.S. 62-3(27a); 16 U.S.C. 796; and 18 C.F.R. 292.101(b)(1). The amendments to G.S. 62-3(27a) and 62-156 became effective on July 27, 2017, when HB 589 became law and apply to standard contract rates and terms approved by the Commission or nonstandard negotiated agreements entered into on or after that date.

On August 8, 2017, Duke and Dominion filed a joint motion, requesting that the Commission take into consideration Session Law 2017-192 as additional authority in deciding the legal and policy issues in this proceeding. The Commission notes that it may take judicial notice of State statutes, G.S. 62-65(b), that a trial court is expected to take judicial notice of public statutes, and that such statutes need not be pleaded. Miller v. Roberts, 212 N.C. 126, 129, 193 S.E. 286, 288 (1937). Based upon the foregoing, including the effective date of the amendments to G.S. 62-3(27a) and G.S. 62-156, the Commission concludes that the Utilities' August 8, 2017 joint motion should be granted. The Commission further concludes that the enactment of G.S. 62-110.8, and the Commission's initiation of rulemaking to implement that section, renders moot the parties' requests to establish a separate proceeding related to the Utilities' use of a competitive procurement process for energy and capacity supplied by QFs. See Springer Eubank Co. v. Four County Elec.

Membership Corp., 142 N.C. App. 496, 543 S.E.2d 197 (2001); see also Order Initiating Rulemaking Proceeding, Docket No. E-100, Sub 150, July 28, 2017. As reflected in the other sections of this order, the Commission considered the authority enacted by S. L. 2017-192 in determining the contested issues in this proceeding, where applicable.

Therefore, based upon the foregoing and the entire record in this proceeding, the Commission finds that the economic and regulatory circumstances facing QFs and electric public utilities in North Carolina has changed since the Commission's last biennial avoided cost proceeding. The Commission concludes that this change makes it appropriate for the Commission to establish avoided cost rates and to alter the contract terms for QFs in light of these changed circumstances. Significantly, actions by the North Carolina General Assembly have resolved legislatively major issues that otherwise the Commission would have been required to resolve. Therefore, the Commission will require the Utilities to file revised rate schedules, power purchase agreements, terms and conditions, and notice of commitment forms that are consistent with the Commission's conclusions reached in this order.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 2-4

The evidence supporting these findings of fact is found in the testimony of Duke witnesses Bowman, Freeman, and Snider; the testimony of Dominion witnesses Gaskill and Petrie; the testimony of NCSEA witnesses Harkrader, Johnson, and Strunk; and the testimonies of Cypress Creek witness McConnell, SACE witness Vitolo, and Public Staff witness Hinton.

Summary of the Testimony

The parties dispute whether the economic and regulatory conditions currently facing QFs and utilities in North Carolina make it appropriate for the Commission to 1) change the length of the long-term levelized rate options that the Utilities are required to offer under the standard option and/or 2) change the eligibility threshold for the standard option, based on the electric generating capacity of a QF.

Length of Term for the Standard Offer

Witness Bowman testified in support of Duke's proposal to eliminate the 5-year and 15-year standard contract term options, and instead, offer a single 10-year contract with fixed avoided capacity rates and avoided energy rates that update every two years as part of the Commission's biennial review of the Utilities' avoided costs.[1]

Witness Bowman acknowledged that the Commission has previously declined to eliminate the 15-year long-term fixed contracts; however, she argued that, at this time, economic and regulatory circumstances compel the Commission to restrike the balance between encouraging QF development, on the one hand, and protecting customers from the risk of overpayment, on the other. In support of her argument, witness Bowman testified that the long-term avoided cost rates, long-term fixed rate contracts, as well as the low threshold to establish a LEO, have resulted in

[1] Because the Commission finds in this order that Duke's proposal to reset avoided energy rates every two years is inappropriate, at this time, this section addresses only the levelized rates which the Commission concludes are required to comply with PURPA's requirements.

large numbers of solar QFs locking in avoided costs rates that are well in excess of the Duke's actual avoided costs in North Carolina for the next 15 years. Further, she testified, that as the number of solar QFs requesting to sell power under the standard avoided cost rates increases, the financial burden and risk of overpayments from these long-term fixed contracts likewise increase for DEC's and DEP's customers.

Duke witness Snider testified in support of Duke's proposed 10-year maximum term standard contract with capacity rates fixed over the term and energy rates readjusted as part of the Commission's biennial avoided cost proceedings. He first testified that the large number of solar-powered QFs, either in development or under construction, have taken the steps required to "lock in" to the Sub 136 and Sub 140 standard avoided cost rates that the Commission previously approved. Witness Snider further testified that the growing risks associated with the long-term financial obligations under existing PURPA standard offer contracts prompted Duke's proposed modifications. Development of these additional solar QFs inevitably means that Duke's financial obligation under PURPA and customers' exposure to overpayments could increase significantly in the future.

Dominion Witness Gaskill testified in support of Dominion's proposal to reduce the maximum term of a standard avoided cost contract from 15 years to 10 years. He testified that the goal of this proposal is to mitigate customers' exposure to the significant above-market payments for QF output that are resulting under current 15-year contract obligations. He testified that since the fixed long-term prices contained in PURPA contracts are based on projections of future costs for electricity, factors such as technology advances, declining equipment costs, and new fuel supply sources unavoidably prevent the rates paid under these contracts from exactly matching the utility's actual avoided cost in any given year of the PPA. Due to the decline in fuel and power prices in the last few years in particular, he testified that Dominion is significantly overpaying QFs with PPAs or LEOs obtained under the 2012 and 2014 standard offers. He also testified that longer term contracts increase the over/under payment created by the levelized rates available under the 2014 standard offer, as the QF receives rates that exceed Dominion's actual avoided cost in the contract's early years, and rates that are less than the actual avoided cost in the late years. Witness Gaskill argued that reducing the maximum standard offer contract term to 10 years will help address the more severe mismatch between locked-in contract prices and actual avoided costs that results from longer contract terms. He further testified that this proposal is consistent with PURPA and FERC's implementing rules and precedent. First, he stated that a 10-year term provides a basis for long-term project financing, as evidenced by the 5 of 12 non-standard contracts Dominion has entered into with solar QFs that contain 10-year terms, and that have shown the ability to achieve financing by either commencing operations or reaching late-stage development. Additionally, he noted that even with a reduced maximum term, Dominion still retains the obligation under PURPA to purchase QF output at the end of the contract period; the shorter contract term simply allows the prices Dominion must pay to align more closely with its actual avoided costs. Witness Gaskill also responded to SACE witness Vitolo's testimony that Dominion does not have 10-year PPAs with QFs sized under 5 MW simply because QFs that size have been eligible for the standard offer 15-year term. Witness Gaskill also stated that the developers of QFs sized at or under 5 MW and those sized greater than 5 MW are not distinguishable, since such developers, as admitted by their witnesses, simply break up their project portfolios into smaller increments to qualify for standard offer rates. He testified that, if developers can obtain financing for large projects with a 10-year term, they should be able to do so for small projects as well, due to the practice of financing pools of small projects together as a group.

Witness Gaskill also testified that assertions regarding QF versus utility-sponsored projects ignore fundamental differences between rate regulated utilities and QFs in terms of organization, regulation, financing, cost recovery, and the obligation to serve customers. Witness Gaskill also noted that Dominion faces a much higher burden than QF developers when seeking to obtain a CPCN and cost recovery for a new project. He testified that the utility must demonstrate that the investment can be used to meet customer needs at the least possible cost, and cited the three Virginia solar facilities referenced by witness Vitolo as cases where Dominion, in seeking CPCNs for those facilities, provided the Virginia State Corporation Commission (VSCC) evidence that customers would save an estimated $32 million net present value below projected market rates. He noted that the VSCC typically only approves a project if it is shown to be favorable for customers relative to other options. Finally, witness Gaskill agreed that longer depreciation lives for utility rate-based assets lower the near-term rate impact for utility projects. He testified, however, that this is appropriate because the lower annual depreciation costs are passed directly to customers via a lower revenue requirement. He noted in contrast that no near-term rate reduction accompanies longer QF contract terms; instead, any savings from the longer depreciation and lower financing costs are kept entirely by the QF, therefore increasing customer risk of overpayment with no offsetting cost benefit.

Witness Gaskill also testified that, while he has no reason to question developers' claims that a shorter term will, all else being equal, change financing requirements, that potential result is not a compelling reason to expose customers to the risk that accompanies 15-year fixed price contracts at avoided cost. He testified that, while PURPA's goal is to encourage QF development, he was not aware of any PURPA provision or rule that entitles developers to rates that ensure a particular rate of return or that guarantees any particular project (or class of projects) the ability to obtain financing. He stated that, instead, FERC promulgated the requirement cited by witness Hinton, that utilities must provide data from which avoided costs may be derived, based on its belief that in order to evaluate the financial feasibility of a QF project, an investor must be able to estimate the expected return on investment with reasonable certainty. He noted that the maximum financial feasibility period that FERC incorporated in that rule was 10 years.

Witness Gaskill concluded that Dominion's experience is that a 10-year term is of sufficient length to allow QFs to obtain financing and complete projects, as evidenced by the five non-standard contracts with 10-year terms that Dominion has entered into with solar QFs, including all but one of such contracts signed within the past two years. He argued that a 10-year term is reasonable for the standard offer contract at this time, because it strikes an appropriate balance between encouraging QF development and protecting customers by reducing the risk of overpayments due to changes in market conditions over time that result in contract rates misaligning with actual avoided costs. He testified that, while PURPA's intent is to encourage QFs, PURPA's express requirements that rates paid to QFs be just and reasonable to utility customers and not exceed the utility's avoided costs, as well as the lack of any particular stated minimum term or guarantee of QF financing, show that the purpose is not intended to place customers at a disadvantage or to force them to pay more than their actual avoided costs. He stated that reducing the maximum contract term to 10 years will help ensure that rates paid to QFs better align with actual avoided costs through the life of the contract while continuing to encourage QF development in North Carolina.

Dominion Witness Petrie testified that the depreciation length of the three solar facilities that Dominion has in rate base is 35 years. Witness Gaskill further clarified the distinction between the avoided cost context and the utility self-build context, particularly with respect to changing cost forecasts. He testified that when Dominion needs additional generation to meet energy and capacity requirements, it determines the least cost option for obtaining that generation, taking into account fuel diversity and other factors, and must obtain Commission approval through a CPCN proceeding for investment in build options. He acknowledged that fuel forecasts can change from the time the decision to build or buy was made, but noted that when Dominion decides to build, the price is below the projected market price, or it would not make that decision. On redirect, witness Gaskill agreed that when Dominion decides to build generation, it must show that it is the least cost option, that there is a need for the generation, and that it could not purchase the generation from another source for less cost. He also agreed that Dominion customers still benefit from a utility-built generator even if the initial cost forecast changes, because the utility will only run the unit when it makes economic sense to do so. He contrasted that option with the take-or-pay context of a QF facility where Dominion has no choice whether to take the power. Finally, he agreed that while Dominion annually adjusts the fuel portion of its rates to reflect increases and decreases in the market through Commission proceedings, such is not the case with avoided cost contracts, which lock in prices for the duration of the contract.

Public Staff witness Hinton testified that the Commission has previously concluded that the long-term contract options serve important statewide policy interests while limiting the utilities' exposure to overpayments. Further, he testified that the Commission has cited G.S. 62-156(b)(1) and 62-133.8(d) for support of its decisions to require long-term contracts under the standard offer, generally, and, has cited G.S. 130A-309.01 to 130A-309.29, with respect to facilities fueled by trash or methane from landfills and environmental policy for support of requiring long-term contracts with facilities fueled by poultry or swine waste. Witness Hinton also noted that the Commission has recognized that FERC has ruled that QFs have a right to fixed long-term avoided cost contracts or LEOs with rates determined at the time the obligation is incurred. He acknowledged that FERC has never specified a minimum or maximum term to be offered by utilities to QFs, but noted the decision in Windham Solar LLC & Allco Fin. Ltd., 157 FERC ¶ 61, 134 (Nov. 22, 2016) (Windham), that QFs are entitled to contracts long enough to allow QFs reasonable opportunities to attract capital from potential investors.

Witness Hinton then addressed the Utilities' arguments that long-term contracts increase the risk of overpayment of avoided costs, which will be passed on to ratepayers through higher rates. He testified that in past biennial avoided cost proceedings the Public Staff has maintained that long-term rates of at least 15 years should be available in order to ensure QFs could secure financing and that the use of a 15-year term is consistent with the long-range planning requirements of G.S. 62-110.1(c) and Commission Rule R8-60, which establishes a 15-year planning horizon. He further testified that, based upon the number of currently operating facilities and facilities in development, the 15-year fixed term contract has been accepted by the financing community and has been beneficial to QFs in North Carolina. Witness Hinton also testified that the Public Staff reviewed policies in other states and finds that some states require shorter term offers and others require longer terms, but there is no clear standard length of term. He continued by observing that avoided cost rates can change considerably over time and that there is always a risk of over- or under-payment, and made an analogy to a utility's commitment to build a generation plant, based upon forecasts of future prices.

On this background, witness Hinton testified that due to the rapid pace of QF development in North Carolina, the Public Staff believes it is appropriate for the Commission to consider a shorter-term structure for avoided cost rates. He argued that this would serve to reduce the risk borne by ratepayers for overpayments over a longer term. Therefore, he concluded that the Public Staff believes that the Utilities' proposal to limit the standard offer term to a 10-year fixed PPA is reasonable. He noted that DEC and DEP have signed 22 PPAs with QFs at 10-year terms, and that 6 of Dominion's 12 non-standard PPAs have 10-year terms, indicating that securing financing terms shorter than 15 years was possible. Witness Hinton further recommended that the Commission continue to monitor the amount of actual QF development and the stability of the 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 seek financing on reasonable terms.

NCSEA witness Johnson testified to how the Commission has implemented PURPA in contrast to other states, including addressing how the length of contract term impacts the ability to finance a QF project. NCSEA witness Harkrader testified that "QFs with a shorter contract term than 15 years would have a much smaller pool of potential debt and equity investors." She testified that, the 15-year contract term has allowed small QFs to access affordable debt and equity capital and enabled a capital structure that is affordable to the QF developer and, therefore, has encouraged QF development. She further testified that the standard offer, particularly the 15 year PPA term and fixed rate, has provided the certainty that has been necessary to encourage QF development in recent years, and this certainty has also played a critical role in driving down the cost of developing solar facilities and contributed to establishing a robust solar market. For example, she testified that when her company first started developing solar QFs in North Carolina, the market was relatively unsophisticated with respect to the development process, as well as the financing process, and the gains that have been made by industry in recent years have helped drive down the cost of solar development in North Carolina. These include: understanding and taking advantage of economies of scale with equipment suppliers; the creation and development of local supply chains and associated service providers related to solar racking, fencing, and landscaping; and the creation of a large, skilled local labor pool trained in installation and construction of solar-powered electric generating facilities. Additionally, the development of the industry has attracted suppliers, such as Schletter Inc. – a manufacturer of solar mounting systems – to relocate in North Carolina, further driving down costs. She concluded that the Utilities' proposed modifications to the implementation of PURPA would disrupt this success and would dramatically alter the landscape of companies that participate in QF development in North Carolina and beyond. NCSEA witness Strunk testified that the utilities' proposed changes to reduce the standard PPA term to ten years and to require the adjustment of avoided energy rates every two years would not provide QFs with a reasonable opportunity to attract capital from investors. He testified that these changes compress the recovery of capital investment in long-lived generation assets into a period too short to allow QFs to attract capital on reasonable terms.

SACE witness Vitolo testified that project financing could be jeopardized by reducing the standard offer term from fifteen years to ten, and that this proposal, in combination with the Utilities' other proposals, may therefore violate PURPA. In addition, he testified that reducing the standard offer contract duration results in differential treatment between QF solar projects and utility solar projects. He stated that the QF industry in North Carolina has demonstrated a clear ability to finance five-MW solar QFs with 15-year contracts, and that the utilities have shown that some larger facilities have been built with ten-year contracts. Witness Vitolo cautioned, however, that this does not necessarily indicate that smaller projects would also be able to obtain financing relying on a ten-year PPA. In addition, he testified that the proposed reductions in avoided energy and capacity rates to the rates approved in the 2014 proceeding may make it difficult for any facilities, large or small, to be financed for ten-year durations.

Witness Vitolo also testified that each of the Utilities have solar photovoltaic (PV) electric generating facilities in rate base, with recovery periods extending from 20 to 35 years. He noted that similar to a longer loan reducing monthly payments, a longer depreciation schedule allows for a reduced near-term rate impact, therefore making the investment more attractive. He argues that this differential treatment between the cost recovery provided for utility solar projects and QF generation is also problematic. Witness Vitolo recommended that, at a minimum, the Commission should maintain current policy by requiring the Utilities to allow renewable QFs to continue to make standard offer terms available for at least 15 years, and the Commission should consider requiring the utilities to offer solar QFs fixed contracts at lengths that match the recovery period of the respective utility's own PV assets.

Cypress Creek witness McConnell testified that along with the pricing contained in a PPA, credit quality and tenor are the most critical components for a renewable energy project developer to be able to obtain financing. He testified that for the majority of projects, lenders are generally unwilling to lend against uncontracted cash flows, and that absent some sort of third-party credit enhancement (like a government guaranty), he has not seen a loan maturity or amortization for a project under 75 MW extend beyond the term of a fixed-price PPA. He further testified that the Utilities' proposal to limit the length of standard-offer contracts to ten-year terms would lead to ten-year amortization periods, which will mean less debt and greater sponsor equity requirements at lower returns and greater risk, and in turn will result in fewer projects getting financed and constructed.

By his post hearing brief, the Attorney General, representing the using and consuming public, argues that there is no evidence that QFs can survive the "simultaneous impact of lower avoided cost rates and the wholesale slashing of contract duration." Citing the testimony of witnesses Harkrader, McConnell, and Strunk, the Attorney General concludes that the reduction in the standard offer term proposed by the Utilities would not offer reasonable opportunities to finance QF projects. He further argues that the reduction in the term (and the eligibility threshold, addressed below), cannot be considered in isolation, rather, several factors will impact the value of the standard offer, for example, the decrease in avoided energy rates based on a decrease in forecasted natural gas and coal prices over the next 10 years. On this point, the Attorney General argues that none of the witnesses who testified that financing would be available for 10-year contracts took these other factors into account. Finally, the Attorney General argues that the evidence that supported the reduction in the length of the standard offer term was not specific to small QFs, citing testimony from witnesses that only addressed 10-year term contracts that were negotiated with QFs with generating capacity of 5 MW or larger.

Eligibility Threshold for the Standard Offer

Witness Bowman argued that it was appropriate and justified at this time to lower the capacity eligibility limit for standard avoided cost rates from 5 MW to 1 MW for QFs, other than QFs small hydro. Witness Bowman testified that in Order No. 69, the FERC recognized that although standard "one-size-fits all" avoided cost rates cannot account for the differences between QFs of various sizes and types, smaller QFs could be challenged by the transactional costs of negotiating individualized rates with utilities. She testified that FERC balanced those concerns by requiring states implementing PURPA to make standard rates and terms available to QFs with a design capacity of 100 kW and smaller. Witness Bowman noted that the FERC also allowed states to put into effect standard rates for purchases from QFs with a design capacity above 100 kW. She testified that at least 20 states currently have standard rates that are limited to QFs less than 100 kW, while utilities in at least 33 states have eligibility caps at or under 5 MW. Witness Bowman also emphasized that Duke is not recommending that the Commission adopt the FERC minimum of 100 kW as an eligibility threshold in this proceeding.

Witness Bowman then recounted the Commission's implementation of the PURPA standard tariff eligibility, beginning with the establishment of the 5 MW eligibility threshold in 1985 when the small power production industry was nascent. She testified that the 5 MW standard offer eligibility criteria was intended to encourage the development of QFs that, at that time, may not have had the resources, experience, or expertise to negotiate with a utility. She next described a "surge" of solar QF development in North Carolina and how the 5 MW eligibility threshold had impacted the North Carolina solar market and Duke's customers. With respect to development of the North Carolina QF solar market, witness Bowman testified that in the last five years, distribution-level, utility-scale solar generation development around the 5 MW standard offer had "exploded" in North Carolina, particularly when compared with the rest of the United States. She testified that solar developers "disaggregate" potentially larger and more cost-effective solar projects to meet the 5 MW standard contract threshold, resulting in ongoing challenges in managing the interconnection of these generators to rural distribution circuits. Witness Bowman also testified that the 5-MW threshold had become a highly attractive development business model for sophisticated and well-capitalized entities from around the country to take advantage of the guaranteed, long-term, fixed rates of the standard contract by obtaining LEOs on behalf of multiple solar facilities with generation capacity of 5 MW or less. She concluded that the 5-MW threshold had served its purpose of encouraging the development of QFs, particularly solar QFs, in North Carolina and should now be evolved.

With respect to the 5 MW eligibility threshold impact on Duke's customers, witness Bowman testified that hundreds of standard contract solar projects between 1 MW and 5 MW had obtained LEOs in North Carolina, resulting in significant long-term financial commitments on behalf of DEC's and DEP's customers. She argued that these long-term contractual purchase obligations are also at rates well in excess of Duke's current system incremental or "avoided" costs. Witness Bowman testified that, since March 2015, when the Companies filed their previous avoided cost rates, approximately 300 projects between 4 MW and 5 MW had obtained CPCNs, thereby potentially establishing LEOs under rates based on inputs to avoided cost calculations made two years ago. She emphasized that these QFs have been able to "lock in" standard, long-term fixed rates, likely for the next 15 years. She further argued that during these lengthy intervals, factors affecting the purchasing utility's avoided costs, such as fuel costs, environmental regulations, and capacity needs, can change dramatically, affecting the utility's actual avoided costs.

Witness Bowman next testified that a 1 MW eligibility threshold was appropriate and justified at this time, based on the current economic and regulatory circumstances. First, she argued that a 1 MW threshold is a reasonable proxy to differentiate between small QFs seeking to install renewable or alternative energy facilities for primarily environmental or other non-commercial purposes by residential and commercial customers, on the one hand, and larger sophisticated commercial enterprises and power generation developers in the business of owning or operating power generation facilities, on the other. Second, she testified that the Companies' net metering tariffs are similarly available to customer-generation with a capacity of up to 1 MW in size. Third, she further testified that the FERC did not require QFs below 1 MW to self-certify as QFs. Finally, she testified that Duke's recent experience was that 1 MW solar projects are more likely to pass the Section 3 Fast Track interconnection study process, allowing both the standardized PPA and Interconnection Agreement to be obtained in a more streamlined fashion.

Witness Bowman also argued that a 1 MW eligibility threshold would result in integrating solar in a more well-planned and coordinated manner, while better protecting customers from paying rates above avoided costs. In support, she cited the Commission's Order on Clarification, issued March 6, 2015, in Docket No. E-100, Sub 140, where the Commission required the utilities to use the most up-to-date data for determining inputs to avoided cost rates for QFs that were eligible for negotiated, as opposed to standard, avoided cost rates. Witness Bowman also recalled that the Commission had previously issued orders in avoided cost proceedings on what factors should be considered in bilateral negotiations between the utilities and QFs. This aligning the avoided cost rates paid to QFs more closely with the utility's avoided costs at the time of the purchase, she argued, meets PURPA's objective of ensuring customers remain indifferent between purchasing utility generation and purchases from QFs at the utility's avoided costs. Moreover, witness Bowman testified, it protects both customers and QFs in periods of rising and declining energy costs.

Witness Bowman also testified that QFs with a nameplate capacity in excess of 1 MW were still entitled to sell power to the utilities at avoided cost rates. These larger QFs would receive avoided cost rates though bilateral negotiations with the purchasing utility and not through the standard offer. She acknowledged that in the most recent avoided cost case, the Commission had declined to approve the Utilities' request to reduce the eligibility threshold to 100 kW, in part based on allegations by QF developers that the Companies' PPA negotiation process was protracted and difficult. Witness Bowman reported, however, that since that decision in 2014, the Companies had gained greater experience in negotiating PPAs with QFs with generating capacity larger than 5 MW. Witness Bowman testified that Duke had negotiated more than 22 "PURPA-only PPAs" with large QFs since 2014, with 10 of these PPAs being negotiated since January 1, 2016. Further, she noted that, of these 10, three were with the same developer, and many are with developers that are owner/developers of other projects that are 5 MW or less and thus eligible for the standard offer. She testified that producing monthly avoided cost calculations for negotiated PPAs has become routine, and the negotiation process has become more standardized. Based on this experience, witness Bowman concluded that the Companies were sufficiently prepared to efficiently negotiate PPAs in good faith with QFs larger than 1 MW.

Witness Bowman also responded to the testimony opposing the reduction in the eligibility threshold from 5 MW to 1 MW. She noted that SACE witness Vitolo's testimony did not reference at all the "tremendous surge" of solar QFs at around the 5 MW level in North Carolina, which was one of the primary drivers of the Companies' proposal. She also disagreed with witness Vitolo's assertion that adjusting the threshold will lead to solar QFs foregoing economies of scale to build smaller projects eligible for the 1 MW standard offer. Witness Bowman testified that the "disaggregation" of larger, more cost-effective, projects to smaller 5 MW ones has created ongoing challenges for DEC and DEP to manage the interconnection of these generators to rural circuits, especially on DEP's increasingly saturated distribution system. In contrast, she argued that the 1 MW threshold would better differentiate between the relatively small projects and the utility-scale solar projects. In response to witness Vitolo's argument that maintaining the 5 MW threshold would result in lower costs overall because it would allow QF developers to retain economies of scale associated with developing a 5 MW project, witness Bowman argued that the "lower costs" referred to would benefit solar QF developers and not the Utilities' customers.

Witness Bowman also responded to witness Vitolo's contention that a significant power imbalance exists between QFs and Utilities in their PPA negotiations. She reaffirmed her direct testimony that utility-scale QFs are no longer being developed by small, fledging developers, highlighting that six large power generation developers, including Cypress Creek Renewables, Strata Solar, and ESA Renewables, accounted for more than 65% of the Companies' combined interconnection queues between 1 MW and 5 MW. She also responded to witness Vitolo's assertion that QFs' negotiations with Duke for a PPA can take months. She noted that, under the current NoC Form approved by the Commission in its Phase II Order, QFs larger than 5 MW have up to six months to execute a PPA after DEC or DEP submits it for signature. Witness Bowman testified that large QFs sometimes wait until that six month period is expiring to execute a PPA, adding to the apparent length of time between the LEO date and execution date of PPAs.

Witness Bowman also elaborated on the Companies' intention to further streamline and standardize the PPA negotiation process as discussed by Public Staff witness Hinton in his direct testimony. She referenced Duke witness Freeman's testimony proposing contracting procedures to foster transparency and efficiency in the PPA negotiation process with QFs, and posited that these procedures could be implemented quickly after input from the Public Staff and other interested parties after the Commission issues a final order in this proceeding. Witness Bowman reaffirmed the Companies' intent to continue to negotiate in good faith and follow FERC and Commission guidance in negotiating PPAs with QFs larger than 1 MW. She again cited the Order on Clarification as directing DEC and DEP to use the most up-to-date data to determine inputs for negotiated rates. She noted that the Order on Clarification also instructed that any party was free to identify specific characteristics of a particular QF that merit consideration in the calculation of negotiated avoided cost rates. Witness Bowman specifically testified that Duke believed that inclusion of ancillary generation costs or other solar integration costs in the calculations of avoided cost rates for QFs ineligible for the standard offer was appropriate under FERC and this Commission's guidance for calculating avoided costs rates. She also testified that QFs may always request to review the inputs of DEC's and DEP's calculations of avoided costs, and that a QF may file a complaint with or engage in arbitration before the Commission if the QF disagrees with these inputs or otherwise believe the Companies are not negotiating in good faith.

On cross-examination by NCSEA, witnesses Bowman and Freeman provided further details on how Duke intends to negotiate with QFs larger than 1 MW. Witness Freeman indicated that the Companies have developed more standardized terms and conditions for large QFs, which would ease the process of negotiations. Witness Freeman declined, however, to support requiring Commission approval of changes to the standardized large QF PPA. He argued that doing so could overburden the negotiation process by requiring approval every time the Companies determine that a change to the standard terms and conditions for large QFs is needed. Witness Freeman added that the Companies had successfully negotiated over 20 such negotiated contracts with large QF developers.

In response to questions from the Commission, witnesses Bowman and Freeman testified about the negotiations between the Duke and QFs over 1 MW. Witnesses Bowman and Freeman agreed that a complaint or arbitration proceeding before the Commission between DEC or DEP and a QF negotiating a PPA could involve many disparate issues, including the minimum length of a PPA and each individual QF's ability to obtain financing. Witness Bowman further responded that Duke does not intend for complaints or arbitrations before the Commission to increase as a result of changing the current standard offer eligibility. Witnesses Bowman and Freeman each testified that the number of QFs seeking PPAs could decrease as developers develop fewer, larger, facilities instead of more, smaller, ones to take advantage of economies of scale. Witness Bowman also testified that Duke does not object to the Commission establishing a formal or informal proceeding to resolve concerns and set expectations on how the Companies would negotiate avoided cost rates for QFs going forward.

Dominion witness Gaskill testified in support of Dominion's proposal limiting eligibility for standard avoided cost rates and contracts to QFs with 1 MW in capacity. He testified that reducing the threshold to 1 MW at this time would allow more QFs to enter into negotiated contracts rather than standard contracts, with several resulting benefits. First, witness Gaskill testified that this would better align avoided costs with each QF's LEO, because standard avoided cost rates, which are updated biennially and are available to any eligible QF that establishes a LEO within the two-year period, can result in QFs receiving rates based on avoided cost calculations that are several years old by the time the projects commence commercial operations. He further testified that this would better align with current market conditions, including changes in gas and power market prices. In addition, he testified that the timely updates possible with negotiated rates help mitigate the compounding impact of long contract terms on the disparity between the standard rates and actual avoided costs.

Second, witness Gaskill testified that allowing more negotiated rates would permit rates and terms to be customized to each specific project and location. He testified that one of the key limitations with the current PURPA implementation approach is the inability to incentivize QFs to locate in one location over another. Because all QFs under 5 MW, regardless of location, are eligible for the same standard offer, developers' main incentive is to locate projects where they can develop them at the least expense—not where the project would provide the most value to customers. The result, he testified, is a heavy concentration of distributed solar on a few substations, stating that approximately 80% of the interconnected distributed solar on Dominion's North Carolina system is located on only 15 substations out of 42. He further testified that, while geographically dispersed distributed solar generation reduces the effect of intermittent cloud cover over any single location, therefore improving reliability and minimizing integration costs (such as increased operating reserves and load imbalance charges), the distributed solar generation in Dominion's North Carolina system does not offer these benefits because it is located on a narrowly distributed geographic and electrically-connected location with little load growth. With more negotiated contracts, he argued, Dominion would have greater opportunity to incentivize projects to locate in areas or on circuits that have a need for new generation. For example, witness Gaskill testified, this could be accomplished by paying for avoided line losses and capacity costs where a QF locates on a distribution circuit with excess load to offset, benefiting both Dominion and the QFs by allowing for increased avoided cost payments for more projects located in more valuable locations.

Third, witness Gaskill testified that, unlike standard offer contracts, negotiated contracts can include provisions that protect customers. For example, he noted that non-levelized rates ensure that the PPA rates better match Dominion's actual avoided costs throughout the life of the contract and protect against overpayment if the QF fails to perform later in its project life. Finally, witness Gaskill noted that 83% (60 out of 72) of the QF PPAs Dominion had signed at the time his testimony was filed were for projects sized 5 MW or below, and that 55 of those 60 standard contracts were developed by only seven different developers. He takes this as an indication that developers develop multiple 5-MW projects in order to take advantage of the two-year-old standard avoided cost rates. He concluded that reducing the standard offer threshold to 1 MW would preserve the standard offer for truly small QFs that need it and would allow rates paid to larger QFs to more closely align with the utility's actual avoided costs and protect utility customers from excessive overpayments.

Witness Gaskill responded to the other parties' testimony, stating that, while Dominion cannot know every potential QF's financing ability, QF developers in North Carolina tend to have large portfolios of generation projects around the country, and to be well-capitalized companies with access to financing resources that afford them the ability to negotiate a PPA. He also observed that these developers break up large portfolios of projects into multiple 5-MW projects in order to qualify for the standard offer, including standard avoided cost rates that can be two years old by the time a QF establishes an LEO. He noted especially the testimony of witness Strunk and witness McConnell that they group together multiple small projects in order to improve the financing terms of a larger portfolio. Witness Gaskill also testified that, in his opinion, large solar developers do not require the standard offer in order to develop QF projects. He testified that, based on his experience, larger developers have resources and sophistication to negotiate contracts, and the market would be better served by removing the incentive to break up the projects into small increments. He noted that witness McConnell's company, Cypress Creek, claimed on its web site that it had raised and invested over $1.5 billion and deployed or developed over 4 GW of local solar facilities, and that it is the largest and fastest-growing dedicated provider of local solar facilities. He opined that it would be illogical for large, sophisticated developers like Cypress Creek to require a standard offer in order to successfully finance and complete solar projects in North Carolina. Finally, witness Gaskill testified that the intent of the standard offer contract is to provide simplified and standard market access for truly small developers, not to permit large developers to break up large solar deployments into small individual projects in order to obtain higher pricing and better financing terms.

Witness Gaskill also testified that the standard offer threshold reduction will ultimately realize a positive benefit to developers, utilities, and customers in all of the areas identified by witness Vitolo. Noting that in some cases a negotiated PPA may take additional time up front, he nonetheless testified that over the life of the contract significantly less resources are required to administer a single 20-MW contract than multiple small project contracts. He testified that, regardless of whether an executed contract is standard or negotiated, it requires approximately the same number of hours to administer, including labor-intensive tasks such as performing monthly meter readings, settlement, invoice and billing, and payments. He stated that with its proposal to reduce the threshold to 1 MW, Dominion intends to encourage developers to build fewer, but larger projects, and thus greatly reduce the number of resources required to originate and administer the volume of QF contracts under consideration.

With regard to the balance of power in contract negotiations, witness Gaskill emphasized that the utility retains the obligation under PURPA to purchase QF output and cannot walk away from a negotiation. He further noted that the procedures for establishing avoided cost rates and the vast majority of terms and conditions of negotiated contracts are fairly well established such that they support efficient and successful negotiations, and that rarely do large contract negotiations include much negotiation or dispute regarding the contract rates themselves, since the rates are calculated based on avoided costs as of the LEO date for each project. He noted that Dominion has successfully negotiated contracts with 12 QFs totaling 214 MW. Finally, with respect to economies of scale and the interconnection queue, witness Gaskill testified that by removing the incentive to divide a portfolio of projects into 5-MW increments, reducing the standard offer threshold to 1 MW will encourage developers to seek larger projects. The change will therefore actually increase economies of scale and reduce the number of projects in the interconnection queue over time, while preserving the benefit of the standard offer contract for the truly small projects.

Concerning the Commission's previous decisions on this issue, witness Gaskill reiterated that the landscape of QF development in this State has changed significantly since the 2014 biennial proceeding. He noted that the Commission in this case must determine what the appropriate standard offer will look like for QFs developed going forward from this case, and that what may have been appropriate two years ago must be adapted to the circumstances Dominion faces today and anticipates it will face in the next two years. Witness Gaskill concluded that more negotiated contracts will provide important protection for customers by reducing the risk of overpayments to a large portfolio of QF projects. Witness Gaskill testified regarding Dominion's first quarter 2017 interconnection queue report filed in Docket No. E-100, Sub 101A. He testified that seven active projects listed on the report have capacities greater than 5 MW and that the capacity of the remaining projects is approximately 5 MW. He also testified that, through repeated negotiations over time, Dominion arrives at essentially a standard contract with each developer.

Public Staff witness Hinton testified that the Commission has traditionally chosen to make standard rates available to a larger number of QFs than the minimum required by FERC regulations, and while it has previously rejected efforts by the Utilities to lower the threshold for renewable QFs, it has also rejected efforts to increase the maximum cap for eligibility for the standard contract. He noted that in the Order on Inputs, the Commission stated that it "must also balance the federal and North Carolina public policy requirement that QFs be encouraged against the risks and burdens that long-term contracts place on customers," and found that increasing the maximum cap for eligibility for the standard contract may tilt the balance too much in the QFs' direction and increase the risks and burdens to ratepayers.

Witness Hinton further testified that in the Sub 140 proceeding, the Public Staff noted that "setting the standard above the minimum threshold required under PURPA allows QFs to receive the benefit of reduced transaction costs and appropriate economies of scale, while providing ratepayers with the assurance that the utilities' resource needs are being met by the lowest cost options available." However, the Public Staff also recognized the significant level of QF development in North Carolina since enactment of the REPS and the number of proposed QFs at or near the 5-MW standard threshold. The Public Staff expressed concerns about the challenges faced by QFs not eligible for the standard offer rates seeking to negotiate with the Utilities, and instead recommended that the Commission maintain the 5-MW standard threshold, finding that it represented an appropriate balancing point.

Witness Hinton then testified that since the Sub 140 proceeding, the significant growth in the number of facilities from which the utilities are obligated to purchase energy and capacity has increased the risk of potential overpayments by ratepayers, and that the higher penetration of resources was posing operational and technical challenges to the utilities. As such, he testified that it is appropriate for the Commission to consider modifications to the standard offer threshold, and recommended that the Commission reduce the standard offer threshold from its current 5-MW level to a level that more currently reflects current conditions in the QF marketplace and better protects ratepayers from the risk of overpayment. Witness Hinton testified as to his evaluation of the following regulatory thresholds: 1) G.S. 62-110.1(g), which exempts nonutility-owned generating facilities fueled by renewable energy resources less than 2-MW in capacity from having to obtain a CPCN from the Commission; 2) Section 3 of the NCIP allows facilities up to 2-MW to be eligible for the Fast Track Process, regardless of location; 3) the Commission's March 30, 2009, Order Amending Net Metering Policy, issued in Docket No. E-100, Sub 83, established 1-MW as the maximum size of a facility in North Carolina eligible to net-meter, which was guided in part by G.S. 62-133.8(i)(6), directing the Commission to consider in its adoption of rules "whether it is in the public interest to adopt rules for electric public utilities for net metering of renewable energy facilities with a generation capacity of one megawatt or less;" and, 4) as pointed out by Duke witness Bowman, FERC has not required QFs below one MW to self-certify as a QF since 2010. In addition, witness Hinton testified that he agreed with Duke witness Bowman that there are also some practical reasons for supporting a reduction in size to 1-MW, including, in particular, the reduced likelihood of a facility between 1- and 2-MW passing the Fast Track Process. He agreed with witness Bowman and Dominion witness Gaskill that the reduced threshold would result in more QFs relying on negotiated PPAs, with a potential benefit that these QFs would be offered avoided cost rates based on more timely information, including updated capacity needs, fuel costs, and other factors that may reduce the exposure of ratepayers to potential overpayment due to changing market conditions.

NCSEA argues that until such time as there is a Commission-approved competitive procurement process under way for the electric utility, the threshold at which a QF qualifies for the Standard Offer should remain at 5 MW. NCSEA witness Johnson testified that the Utilities' proposed changes, including the proposed reduction in the eligibility threshold for the standard offer, have the effect of increasing the risks faced by QFs and make it more difficult to finance QF projects. NCSEA witness Harkrader testified to the difficulties associated with negotiating a PPA with the electric utilities, including that the Utilities accept few, if any, revisions to the PPA. In addition, Harkrader testified that in negotiating a PPA, the utility retains the right to change key terms and conditions. She testified that the length of the PPA term is an example of such a key term. Thus, she testified that NCSEA's position is that, given that an electric utility retains discretion when negotiating PPAs to set key terms that bear directly on whether a QF has a reasonable opportunity to attract capital from potential investors, maintaining the eligibility threshold for the standard offer at 5 MW results in fewer QFs having to negotiate PPAs.

Cypress Creek witness McConnell testified that scale is critical in project development, and that reducing the standard offer contract threshold to 1 MW would make financing projects in North Carolina much more challenging. He testified that much of the financing for 5-MW facilities was obtained through grouping a number of projects together into portfolios to create critical mass for debt and tax equity investors. If the standard offer threshold were lowered to 1 MW, an even larger number of projects would need to be grouped together into a portfolio, and the portfolio size would quickly become unmanageable due to the amount of due diligence required for that number of projects, which would largely shut out the institutional market from financing standard offer contracts.

SACE witness Vitolo testified that the Utilities' proposal to reduce the eligibility threshold for the standard offer will have several negative repercussions. First, he noted that the bilateral negotiation process for those facilities that do not qualify for the standard offer contracts are lengthy and resource-intensive and also take place with a significant power imbalance since the incumbent utility is generally the QF's only potential customer for its power. Second, he testified to the effect that the reduction in the standard offer contract threshold would have on economies of scale, stating that while variable costs such as the cost of panels, inverters, and land grow predictably with the size of the project, fixed costs such as legal, administrative, and some engineering costs do not. As such, a larger project has a lower total cost per kilowatt than a smaller project. Reducing the capacity limit for standard avoided cost rates, he testified, may require the developer either to forego economies of scale that were otherwise available at the previous 5-MW threshold and instead build a smaller project to avoid the costs and risks of negotiation, or to retain the economies of scale of the larger project but also bear the cost and risk of a bilateral negotiation. Witness Vitolo also testified that reducing the eligibility for a standard offer contract could increase the number of projects under development, thereby adding additional stress on utility interconnection queues and the resources that the utilities have available to conduct bilateral negotiations.

Discussion and Conclusions

In light of the change in the economic and regulatory circumstances currently facing QFs and utilities in North Carolina, the Commission now addresses whether the evidence of these changed circumstances demonstrates that it is appropriate to approve the Utilities' proposals to require that the standard PURPA contract be limited to one 10-year term option available to QFs with a generating capacity up to 1 MW.

The Commission begins by recognizing 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. Order No. 69 establishes the appropriateness of a fixed QF contract price for energy and capacity at the outset of the QF's obligation because fixed prices are necessary for an investor to be able to estimate with reasonable certainty the expected return on a potential investment, and therefore, its financial feasibility before beginning the construction of a facility. While the Commission is mindful that for a QF that chooses to provide energy or capacity pursuant to a LEO over a "specified term," that term must be long enough to allow the QF reasonable opportunities to attract capital from potential investors, Windham, at 134, FERC has also noted that its regulations do not specify a particular number of years for such LEOs. Id. at fn. 13. In addition, PURPA requires the Commission to put into effect (with respect to each electric utility) standard rates for purchases from QFs with a design capacity of 100 kW or less, and permits the Commission to put into effect standard rates for purchases from QFs with a design capacity of more than 100 kW. 18 C.F.R. 292.304(c).

As testified to by the witnesses in this proceeding and recognized by the Commission in its Order on Inputs, establishing the length of the standard offer term and the eligibility threshold for the standard offer, requires a balancing of costs, benefits, and risks to all parties. The Commission finds persuasive the testimony of Duke, Dominion, and the Public Staff's witnesses that demonstrates a causal link between the 15-year standard offer term and the 5-MW eligibility threshold and the distortions in the marketplace for QF-supplied power. The Commission agrees with Duke witness Bowman that the Commission's past decisions requiring the offering of a 15-year fixed rate to QFs up to 5 MW in generating capacity has achieved PURPA's goal of encouraging QF development, particularly solar-powered QFs. Accordingly, the Commission finds it appropriate to eliminate the requirement that the Utilities offer long-term capacity payments and energy payments for a 15-year term and that the standard offer be available to QFs with a generating capacity up to 5 MW. In determining the appropriate length of the standard offer term and eligibility threshold for the standard offer, the Commission will continue its approach of balancing the federal and North Carolina public policy requirements to encourage QF development against the risks and burdens (such as overpayment, default, and stranded costs) that long-term contracts place on the Utilities' customers. Unlike in the past, when the facilities entitled to long-term rates were "generally of limited number and size," see Phase II Order at 11, the evidence in this proceeding demonstrates, as witness Hinton testified, "the sheer volume of QF projects currently being developed in North Carolina is unparalleled."

The Commission is not persuaded by SACE witness Vitolo's argument that a 10-year maximum PPA is discriminatory in violation of PURPA because it results in QF solar projects being treated differently than utility projects with respect to recovery of costs. Instead, the Commission agrees with Dominion witness Gaskill and Duke witnesses Snider and Bowman that a utility must operate under cost-of-service rate recovery, which differs from how QFs recover their costs. For example, when a utility builds a plant and places it in rate base, it does not receive forecasted avoided cost for energy and capacity like the QFs, but instead earns a return on capital invested to meet its obligation to serve. Further, the addition of new utility-owned generation is driven by integrated resource planning that is scrutinized by the Public Staff and other interested parties before the Commission, and a specific plant addition is subject to review in CPCN proceedings, where the utility must usually demonstrate that the investment can be used to cost-effectively service customer energy and capacity needs. In contrast, a QF has no limit on, and the Commission has no right to review, the amount of debt QFs may use for financing, the return on equity, or the overall rate of return. Significantly, as witness Gaskill testified, the longer depreciation lives for utility-owned assets are intended to lower the near-term rate impact for utility projects because lower annual depreciation costs are passed directly to the customers through a lower revenue requirement. In contrast, any such savings from longer PPAs and lower financing costs are retained as profit by the QF developer and its investors and are not flowed through to customers. The Commission concludes that matching these recovery periods would shift the balance too far towards encouraging QFs and exposing the Utilities' customers to more overpayment risk.

The Commission is also not persuaded that reducing the standard offer term from the 15 years to 10 years will violate PURPA's requirement that the LEO be long enough to allow the QF reasonable opportunities to attract capital from potential investors. The Utilities' witnesses testified that Duke and Dominion have offered, negotiated, and executed PPAs with terms of 10 years with larger QFs. Witness Bowman testified that no Southeastern state requires a standard offer term of longer than 10 years, and witness Hinton testified that based on the Public Staff's investigation, a 10-year term is reasonable to allow QFs to attract financing in light of current conditions. Further, although testifying in opposition to the Utilities' proposal, NCSEA witness Harkrader testified that a 10-year standard offer term will significantly reduce the pool of debt and equity investors willing to invest in a QF, but notably, she did not testify that a 10-year term would eliminate opportunities to attract investment. Likewise, witness McConnell testified that for small QFs, the reduction to a 10-year term would cause difficulty in obtaining sufficient debt and equity to finance construction and operation. Witness McConnell also did not testify that a 10-year term would eliminate a reasonable opportunity to attract investment, although he speculated that the difficulty could become an impossibility. NCSEA witness Strunk testified that the proposed reduction in the term of the standard contract and the other changes that the Utilities have proposed would not provide QFs with a reasonable opportunity to attract capital from potential investors. The Commission first notes that the proposed two-year reset in avoided energy rates is not approved in this order. This mitigates the impact that witness Strunk addressed in his testimony. Further, the Commission finds that the Utilities' evidence of the number of ten-year negotiated contracts with QFs that are currently operating sufficiently rebuts witness Strunk's arguments. For similar reasons, the Commission is not persuaded by the Attorney General's arguments based on this testimony. Therefore, the Commission concludes that the difficulties QFs might experience in attracting investment under a 10-year standard offer do not demonstrate that a 10-year term violates PURPA by eliminating the QF's reasonable opportunity to attract investment; rather, a reduced pool of investors and more difficulty in attracting investment are natural consequences of the rebalancing of the requirements to encourage QF development against the risks and burdens to the Utilities' customers.

Turning to the eligibility threshold for the standard offer, the Commission finds persuasive the evidence of the large number of QF projects currently operating or under development with a generation capacity at, or just below, 5 MW. This demonstrates a clear causal link between the Commission-established standard offer eligibility threshold and the growth and development activity of QFs in North Carolina. The Utilities' primary justification for reducing the standard offer eligibility threshold from 5-MW to 1-MW is that avoided costs rely on forecasts that carry a risk of inaccuracy. The Utilities' witnesses testified that reducing the eligibility threshold will improve the accuracy of calculation of avoided cost rates by increasing the use of negotiated contracts with QFs with rates based upon more timely and accurate calculations of the Utilities' avoided costs, and witness Hinton largely agreed with this concept. Mindful of FERC's direction to make ratepayers indifferent between a utility self-build option or alternative purchase and a purchase from a QF, the Commission finds merit in this argument and concludes that this evidence supports reducing the standard offer eligibility threshold.

In opposition to the proposed reduction in the eligibility threshold, the intervenor parties' arguments focus on virtues of the current 5-MW threshold: it allows QF developers to capitalize on economies of scale and it facilitates reduced transaction costs for QFs. The Commission agrees with these parties' witnesses that these virtues have been important in encouraging QF development in North Carolina. However, unlike in the Sub 140 proceeding, where the Commission found that very few negotiated contracts with QFs larger than 5-MW have been executed, see Order on Inputs at 20, in this proceeding there is substantial evidence that the Utilities and QFs larger than 5-MW have successfully negotiated contracts. Further, Duke witnesses Bowman and Freeman testified that Duke has gained experience negotiating contracts with larger QFs and is committed to streamlining that process in the future. Witness Bowman also testified that Duke does not intend to increase the number of complaint or arbitration proceedings brought to the Commission when these negotiations fail. This evidence tends to mitigate the impact of a reduced eligibility threshold.

The Commission recognizes and takes seriously the intervenor parties' concerns that the Utilities will use "take it, or leave it" negotiation tactics. The Commission concludes that both parties to a negotiated PPA are under an obligation to act in good faith in the negotiation, execution, and performance of their contract obligations. This obligation to act in good faith, and the Commission's ability to enforce it against either party through complaint and arbitration proceedings, also mitigates the effect of the reduced eligibility threshold. Finally, with regard to economies of scale, the Commission finds persuasive the testimony of Dominion witness Petrie that standard and negotiated contracts require approximately the same number of hours to administer (including labor-intensive tasks such as performing monthly meter readings, settlement, invoice and billing, and payments) and that Dominion intends to encourage developers to build fewer but, larger projects, and thus greatly reduce the number of resources required to originate and administer the volume of QF contracts under consideration. This evidence also mitigates the impact on QFs' ability to take advantage of economies of scale.

On balance, in light of the change in the marketplace for QF-supplied power, the Commission finds that a reduction in the eligibility threshold is appropriate, and for reasons discussed above, a reduction will not violate PURPA's requirement to encourage QF development. The witnesses that proposed reductions in the standard offer eligibility threshold have suggested three alternatives: 1 MW, 2 MW, or something else, perhaps 3.75 or 4 MW. The Utilities' witnesses cited other regulatory contexts and practical reasons in support of their proposed 1-MW threshold, and Public Staff witness Hinton recognized the merits in this reasoning. Witness Hinton also suggested these considerations could also support a 2-MW threshold, but concluded that the 1-MW threshold "may have more practical significance," including allowing more QF contracts to be based on more timely information that "may reduce the exposure of ratepayers to potential overpayment due to changing market conditions." NCSEA witness Johnson suggested that the proposed 1-MW threshold might be "too extreme." Instead he suggested a 3.75 or 4-MW threshold would allow the Commission to evaluate the impact on the QF marketplace and, in any event, acknowledged that this issue could be revisited in a future biennial avoided cost proceeding. Finally, the Commission takes notice of amended G.S. 62-156(b), providing that, in implementing the standard purchase agreement long-term contracts up to ten years for the purchase of electricity from small power producers with a design capacity up to and including 1,000 kW (or 1 MW) shall be encouraged to enhance the economic feasibility of these facilities.

Based upon the foregoing and the entire record in this proceeding, the Commission finds that it is appropriate to require the Utilities to make the standard offer contract available to QFs with a generation capacity of up to 1 MW. As to those QFs that are "small power producers," as defined in G.S. 62-2(27a), the Commission concludes that G.S. 62-156 resolves this issue. As to those QFs that are cogeneration facilities, the Commission concludes that the evidence demonstrates that this reduction will promote PURPA's goal of making the Utilities indifferent to whether the energy or capacity purchased is supplied by a QF, through self-build, or otherwise, by increasing the number of QF projects that will negotiate contracts. The Commission further concludes that this reduction will not violate PURPA's requirement to encourage QF development, in light of the extensive record of the amount of QF-supplied power and number of QF projects operating and in development in North Carolina, including a growing number that have successfully negotiated and executed contracts with the Utilities.

The changes in the standard offer term and eligibility threshold, viewed jointly with the other changes being adopted by the Commission, 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. One part of this effort is the Commission's implementation of the General Assembly's directives enacted in HB 589. The Commission will 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.

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 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. The Commission recognizes that the importance of a Commission-recognized active solicitation may be greater in the near future than it has been in the past as the Commission works to implement the requirements of newly enacted G.S. 62-110.8, and the Commission intends to develop its rules for the competitive procurement of renewable energy and implement that program in a manner that provides the certainty that Utilities and QFs need.

The Commission further concludes, based upon the foregoing and the entire record herein, that it is appropriate for Dominion to 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, including the payment of capacity credits based on the PJM Reliability Pricing Model (RPM), subject to the same conditions as approved in the Sub 106 Order and most recently restated in the Order on Inputs, except as modified by this order.

Finally, the Commission finds good cause to make clear that the conclusions reached in this section apply equally to hydroelectric QFs without storage capacity (commonly called run-of-the-river hydro facilities). DEC and DEP filed Schedules PP-H and PPH-1, respectively, in which they proposed standard offer fixed rates available to run-of-the-river hydro QFs that are 5 MW and less for 5-, 10-, and 15-year terms, reflecting the terms and conditions of the Hydro Stipulation, which was filed and approved in Docket No. E-100, Sub 140. In doing so, Duke relied on the State policy set forth in G.S. 62-156 and the Commission's approval of the Hydro Stipulation. The Commission has historically relied on this State policy supporting small hydro facilities and the relatively small and finite amount of small hydro capacity in the state, as justification for treating these QFs differently than other QFs. However, these provisions were repealed or substantially amended by the enactment of S.L. 2017-192, undermining the policy rationale that prompted the Commission to approve the Hydro Stipulation in the Order on Inputs. Therefore, the Commission concludes that G.S. 62-156 requires that run-of-the-river hydro QFs be treated similarly to other QFs with regard to the Commission's implementation of the standard offer contract.

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

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 5 AND 6

The evidence supporting these findings of fact is found in the testimony of Duke witnesses Bowman and Snider; Dominion witnesses Gaskill and Petrie; Public Staff witness Hinton; NCSEA witness Johnson; Cypress Creek witness McConnell; and SACE witness Vitolo.

Duke witnesses Bowman and Snider testified in support of Duke's proposal to calculate capacity costs taking into account each utility's relative need for additional generating capacity as determined by their respective IRPs. Witnesses Bowman and Snider both testified that PURPA requires that QFs be fairly and reasonably compensated for the incremental capacity and energy costs that, but for capacity and energy provided by the QF, the utility would be forced to generate or purchase elsewhere to serve its customers. If the purchase of power from a QF does not, in part or in total, avoid the utility's need to incur incremental capacity and energy expense, then the QF should not be compensated for providing that benefit. In support of her testimony, witness

Bowman cited FERC's decision in Ketchikan, holding that while a utility is legally obligated to purchase energy or capacity provided by a QF, the purchase rate should include only payments for energy or capacity that the utility can use to meet its total system load.[1] She also cited N.C. Gen. Stat. § 62-156(b)(2), providing that "a determination of the avoided energy costs to the utility shall include . . . the expected costs of the additional or existing generating capacity which could be displaced." Witness Bowman acknowledged that the Commission has cited FERC's Hydrodynamics decision,[2] as supporting its determination that the Utilities should not include zeros in the early years when calculating avoided capacity rates. She distinguished Hydrodynamics from the circumstances of this proceeding, noting that Hydrodynamics pertained to a limit on installed capacity purchases by a utility and not to a utility proposal to recognize a capacity value only in years where the utility's IRP showed a need for such capacity.

Witness Snider also recommended that the Companies' relative need for incremental generating capacity should be accounted for in calculating its avoided capacity rates, arguing that prior to the year in which the next generation unit is needed to serve system load, the utility does not have a capacity need to avoid. Thus, witness Snider testified, the calculation of the capacity portion of the avoided cost rate should not ascribe value for years prior to the first avoidable capacity need. Witness Snider further testified that the first capacity need for both Duke utilities occurs in the 2022-2023 timeframe, as shown in their 2016 IRPs. He also testified that QFs under the standard offer tariff will receive capacity payments in years prior to the Companies' first capacity need because the QFs will receive a levelized capacity rate reflecting a lower annual payment to account for those initial years in which there is no avoidable capacity costs. Witness Snider concluded that this proposal is fair to Duke's customers because with this adjustment, the Duke utilities' customers would only be paying QF capacity payments equal to the economic value of an associated avoided capacity cost.

Dominion witnesses Gaskill and Petrie testified in support of Dominion's proposal to include no payment for capacity with its standard offer avoided cost rates. Witness Gaskill testified that, even if Dominion did have a near-term need for additional generation capacity in North Carolina, which it does not, additional distributed solar generation beyond what is already under contract would not allow Dominion to avoid future capacity expansions. In support of his argument, he testified that FERC has clearly stated that while utilities may be obligated under PURPA to purchase from QFs, an avoided cost rate need not include payment for capacity where a QF does not allow the purchasing utility to avoid building or buying future capacity—that, when a utility's demand for capacity is zero, the cost for capacity may also be zero. Further, he testified that FERC's rules implementing PURPA define avoided costs as the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from a QF, the utility would generate itself or purchase from another source. He stressed the importance of the "but for" language in that definition in the context of capacity payments, noting that it is not the case that, "but for" the distributed solar QFs on its North Carolina system, Dominion would purchase or self-supply capacity. He concluded that, because it will not avoid capacity need due to incremental distributed solar generation in North Carolina, a capacity rate of zero accurately reflects Dominion's actual avoided costs for QF contracts signed today. He testified that unlike

[1] See City of Ketchikan, Alaska, 94 FERC ¶ 61,293 (2001) (Ketchikan).

[2] Hydrodynamics, 146 FERC ¶ 61,193 (2014) (Hydrodynamics).

previous QFs interconnecting at distribution level that acted as load reducers and, by reducing Dominion's load obligation, deferred the need to buy or construct new capacity, because distributed solar generation now exceeds load in this area, there is no need for additional distributed solar in Dominion's North Carolina service area, and that because incremental distributed solar QF generation in North Carolina will not allow it to avoid capacity need, a zero capacity payment accurately reflects Dominion's actual avoided costs for QF contracts signed today.

Witness Petrie testified that several factors support this proposal. First, he testified that Dominion's 2016 IRP showed no capacity need until 2022 at the earliest, and that its preliminary updated load forecast as of December 2016 pushes that need for incremental capacity out to 2024. He further testified that the most recent PJM load forecast from January 2017 shows no need for capacity for Dominion until after the 2026 timeframe. Additionally, witness Petrie testified that, even if a need for new capacity did exist within Dominion's current long-term planning horizon, because its North Carolina service area is saturated with distributed solar QF projects, any new distributed solar generation added going forward will have little to no peak load reducing effect on the system. He testified that new solar QFs are not effective substitutes for new dispatchable generation, such as a CT, unless they are located near areas with increasing load growth and where additional generation is needed to reduce congestion and improve reliability. However, he testified that this is not the case for solar QFs in Dominion's North Carolina territory because while previous QFs interconnecting at the distribution level acted as load reducers, deferring the need for new capacity, distributed solar generation now exceeds load in the North Carolina service area, such that there is no more load to offset. For similar reasons, he noted, additional distributed solar in this area will not improve overall system reliability, especially with regard to meeting wintertime peak demands. Considering all of these factors, witness Petrie concluded that Dominion cannot avoid building or buying capacity by purchasing from new distributed solar generation in its North Carolina service area. Witness Petrie also testified that Dominion is considering the addition of aeroderivative CTs as quick-start, flexible units that can balance the system as more intermittent, non-dispatchable solar generation resources are added. However, because these aeroderivative CTs have a higher installed cost than the large frame turbines that Dominion has built since the year 2000 (an estimated 67% more than other CTs), their addition will result in increased long-term capacity costs for customers.

Witness Petrie further testified that pricing for solar generation should reflect its lack of dispatchability and limited usefulness during system emergencies. He testified that FERC's rules list several factors that should be considered when determining avoided cost rates for QFs including, among other factors, the availability of a QF's energy or capacity, the utility's ability to dispatch the QF, the QF's expected or demonstrated reliability, and the usefulness of the QF's energy and capacity during system emergencies. Witness Petrie also noted his understanding of FERC's recent explanation that its rules permit state regulatory authorities to consider factors such as capacity availability, dispatchability, reliability, and the value of energy and capacity when determining avoided cost rates, and, based on these factors, to set lower rates for purchases from intermittent QFs than for purchases from firm QFs. Witness Petrie also cited recent changes to PJM's capacity market rules as further evidence that additional distributed solar generation in Dominion's North Carolina service area is not the type of reliable capacity that would allow it to avoid capacity needs. He testified that these rule changes were intended to better reflect the changing resource mix in PJM, including the growing volume of intermittent generation, and to better align resource payments to performance. He noted that intermittent resources are particularly challenged under the new rules, as they can be subject to severe penalties for non-performance during summer and winter peak hours. He also pointed out that PJM training materials issued after FERC approved the new rules suggest that an acceptable offer for a 100-MW nameplate solar facility would be from 0 to 20 MW of firm capacity. He concluded that these changes demonstrate that solar capacity, as compared to the firm capacity of a dispatchable and reliable CT, is not capable of sustained, predictable operation during emergency conditions, and has limited value in the new PJM capacity market, from which Dominion's actual avoided costs are derived.

Witness Petrie also testified that Dominion, which has experienced winter peaks in two of the last three years, as well as PJM, have increased their focus on planning for winter reliability, the costs for which include procuring fuel supply backup, additional gas pipeline capacity, and improved winter testing and operations. He noted that the spikes in demand during periods of extreme cold over the last several years show the volatility of winter peak loads and the need for dispatchable generation on the system. He noted also that because solar generation output is near zero at 7 a.m. on cold winter mornings when these system peaks occur, a CT is still required in the winter.

Finally, witness Petrie testified that the addition of large amounts of distributed solar resources is likely to shift the time of the summer peak to a later hour in the day, while not impacting the timing of the winter peak load due to their minimal output at that time. He noted that, when Dominion reaches the threshold of aggregate solar additions of about 1,000 MW across its North Carolina service area, the summer peak hour is expected to shift from 5 pm to 6 pm or later. Witness Petrie testified that, as the summer peak hour shifts later in the day, any additional solar generation produces less summer peak load reducing effect, and is thus less effective in deferring or avoiding the next required capacity resource because solar output decreases in the later hours of the evening and, therefore, has lower capacity value. The marginal value of solar capacity, therefore, decreases as more solar generation is added to the system. Witness Petrie concluded that Dominion's proposal to make no capacity payments to QFs receiving the standard offer accounts for the fact that, due to all of these factors, additional North Carolina QF solar resources will not allow it to defer or avoid capacity needs. This proposed modification would also, he stated, avoid burdening customers with avoided cost payments that exceed Dominion's actual avoided costs. Witness Petrie concluded that given these considerations and the factors described in his direct testimony, the appropriate capacity rate for new QFs located in this area is zero cents per kWh for the duration of the standard offer contract.

Witness Petrie testified that SACE witness Vitolo's assertion that as a PJM member, Dominion only has summer capacity needs, is incorrect and oversimplified. He testified that the PJM capacity market reflects the need for capacity planning to meet both summer and winter peaks, since under its new capacity market rules, PJM generators must provide reliable capacity during all months of the year. He disagreed that PJM has a surplus of winter capacity, citing the shortage of available generation during the winter of 2014 that demonstrated the need for the new rules. He also testified that since solar resources have little or no capacity to generate at the winter morning peak, they are subject to significant capacity performance penalties if they bid into this market, since under the new rules they are subject to the same financial penalties that apply to conventional fossil-fueled resources for non-performance on critical days. Witness Petrie also testified that the 38% capacity value cited by witness Vitolo denotes capacity injection rights, not the market capacity value, of solar resources. He emphasized that, on a risk adjusted basis, the capacity credit of a solar resource offered into PJM's capacity market is in the nameplate capacity range of 0 to 20% (based on PJM's assumption that a typical solar facility may provide 38% in the summer, but only 2% in the winter). Whether a solar generator bids into the PJM market at 0 or 20% depends on how much penalty risk the generator is willing to accept. He testified that this reduced capacity credit percentage, combined with the potential penalties, demonstrates that, from a reliability perspective, solar resources can only be counted on for a small portion, if any, of their nameplate capacity, and that continuing to pay new solar QFs rates for avoided capacity, when they do not defer or avoid any capacity need, results in an overpayment beyond Dominion's actual avoided costs.

Witness Petrie also addressed Duke's proposal to include zeros in the calculation of the capacity rates for the years where the utility does not have a capacity need. He stated that, in the event that the Commission declines to accept Dominion's proposal to set capacity rates to zero for the duration of the standard offer contract, Dominion would agree with Public Staff witness Hinton's conclusion that Duke's proposal is reasonable and appropriate. He testified that while Duke's proposal would still result in Dominion overpaying QFs, it would come closer to valuing the capacity appropriately over the course of a long-term PPA than would paying a QF for capacity over the entire term, including for years in which there is no demonstrated need.

Witness Petrie agreed with witness Hinton that in the current circumstances it is appropriate for the Commission to reconsider this issue, since the traditional application of the peaker method is resulting in overpayment in excess of actual avoided costs and is not sending proper price signals to the market. He noted that there is historical precedent for the Commission allowing the utility to pay zero for capacity during the front years of a QF contract, citing orders issued in the 1994, 1996, and 1998 avoided cost proceedings in which the Commission recognized that, where no capacity costs are avoided, no capacity credit should be reflected in the capacity rate calculation. He stated that the evidence in this case is analogous to those proceedings.

Witness Petrie disagreed with NCSEA witness Johnson's argument that paying QFs for capacity only when the utility actually shows a capacity need discriminates against QFs. Witness Petrie testified that, as a regulated utility, Dominion has an obligation under the law to serve its customers reliably and at least cost. He testified further that North Carolina QFs cannot defer or avoid the need for new capacity because they do not reduce load on Dominion's system. He testified that paying for capacity when it is not needed or avoided contradicts the PURPA requirement that the rates a utility pays for QF output should not exceed the utility's avoided costs. He also testified that, contrary to witness Johnson's assertion, the principle of ratepayer indifference is also violated if customers pay the QF for capacity that is not actually avoided, because those customers are paying for something they do not receive. He noted that the determination of avoided costs and rates to be made in this proceeding is not a theoretical exercise, but instead represents real customer costs.

Finally, witness Petrie testified that, contrary to witness Vitolo's testimony, the circumstances of the Ketchikan case, in which he understood FERC to have found that if the utility does not have a demonstrated capacity need it should not be required to pay for incremental QF capacity, are similar to the current situation in North Carolina. He noted that as shown in Ketchikan, Dominion also currently has no near-term incremental capacity needs. He acknowledged that in the 2014 biennial proceeding, the Commission cited FERC's later

Hydrodynamics decision in support of its determination in that docket that the Utilities should not include zeros for capacity in the early years when calculating avoided capacity rates. He testified that the situation in Hydrodynamics differed from the circumstances at issue in Ketchikan and those at issue in this proceeding, because it addressed a utility proposal to limit installed capacity purchases with no connection between that limit and the utility's own actual need. He noted that, in Hydrodynamics, FERC reiterated its earlier conclusion that when a utility's demand or need for capacity is zero, avoided cost rates need not include capacity cost. He stated that such is the case here, and therefore that the Ketchikan rationale does apply to this case and to Dominion's proposal.

Dominion witness Petrie clarified that it was not relevant that Dominion used the differential revenue requirement (DRR) method of determining avoided costs during the 1990s cases in which the Commission recognized that no capacity credit should be included where no capacity costs are avoided. He testified that, regardless of avoided cost methodology, if there is no demonstrated capacity need, the utility should not be required to pay for capacity. He agreed that all three traditional avoided cost methodologies have the same purpose: reasonably estimating the utility's future avoided cost.

Dominion witness Gaskill testified that the number of QF PPAs and related capacity that Dominion has entered into increased from 72 PPAs and 500 MW of capacity as of the date of his direct testimony to 76 PPAs and 521 MW of capacity as of the hearing date. Witness Gaskill also answered questions from NCSEA counsel comparing the amount of distributed solar generation on Dominion's North Carolina system as described in his testimony to the amount of solar generation either connected to its system or having an executed Interconnection Agreement that was identified in its February 1, 2017 interconnection queue report filed in Docket No. E-100, Sub 101A (and entered as NCSEA-Dominion Cross Exhibit 1). He clarified that the queue report is prepared by Dominion's interconnection team from which he operates separately. He testified, however, that the 435 MW of operational solar capacity noted in his testimony is consistent with the 345 MW of operational interconnected solar capacity reflected in the queue report, because the 435 MW total includes 90 MW of solar that is in the PJM wholesale interconnection queue, but is interconnecting to Dominion's distribution system. Similarly, he testified that the difference between his estimate of 363 MW in study phase as shown in Figure 2 to his direct testimony, and the 282 MW designated as Project A, Project B, or "Subordinate" in the queue report, is also likely due to his Figure 2 including PJM queue projects. He also noted that the total MW reflected by the queue report as "connected" and "IA executed" projects—519 MW—is comparable with his updated testimony that Dominion has entered into PPAs for 521 MW of solar capacity.

Witness Petrie testified that Dominion occasionally enters into contracts for capacity outside of QF agreements, and recently acquired replacement capacity related to the March 2017 deactivation of the Roanoke Valley Power facility (ROVA), some of which it filled through short-term capacity purchases in the PJM market. Witness Gaskill testified that the term of the contract for Dominion's purchases from this facility extended through mid-2019, but because the facility deactivated, Dominion was obligated to locate capacity to replace what that facility had committed through PJM's wholesale capacity market. He testified that Dominion is self-supplying the remainder of the capacity previously supplied by this facility. Witness Petrie agreed in response to questions by counsel for SACE and the Public Staff that Dominion engages in generation and transmission planning on a system wide basis, including North Carolina and Virginia.

Witness Gaskill further testified that, generally speaking, non-wholesale contracts, such as a contract for a QF selling under PURPA, would not be eligible to replace a capacity commitment by being bid directly into the PJM wholesale capacity market, because they are not participants in that market. Specifically as to the ROVA facility, he testified that because that facility had been committed into the PJM capacity market as a capacity performance resource, eligible replacement capacity had to be located in that market, and behind the meter QF solar generation would not have qualified as eligible replacement capacity for a capacity performance resource. He noted that the potential capacity value that can be derived from solar QFs is not from their generation of power but from their load reducing effect, because as they reduce the peak load over time, they reduce the amount of capacity Dominion must procure through PJM. But, as shown in this case where this generation exceeds the load requirements, there is no load reducing effect and no impact on PJM capacity market procurement. Witness Gaskill also clarified that as an alternative to putting power to Dominion as a QF, a developer could become a PJM market participant and sell its output into PJM. Witness Gaskill confirmed that in response to a Public Staff discovery request he reconstructed Figure 1 from Dominion's Initial Filing, which had shown the tremendous recent growth in QF solar development in its North Carolina service area since 2013, to show the current level of QF solar development on the North Carolina portion of Dominion's system compared to its system average on-peak load.

Public Staff witness Hinton testified regarding the traditional application of the peaker method and its valuing of capacity over the entire planning period. He stated that according to the theory of the peaker method, the utility's generating system is operating at the optimal point, the capital cost of a peaker (based on a CT) plus the marginal running costs of the generating system will equal the avoided cost of a baseload plant and constitute the utility's avoided costs. He noted that in reality, however, no utility system operates at the most optimal point and utility planners have to deal with unexpected changes in load, fuel costs, and other factors that challenge optimality. He expressed concerns that the rapid and substantial increase in QF development raises doubts as to whether the traditional application of the peaker method would continue to be appropriate and provide the market with a correct price for capacity. He further noted that an end result of the traditional long-run application of the peaker method is that every kilowatt-hour (kWh) generated during on-peak hours provides capacity value and this value is quantified from the first day of QF operation, regardless of the utilities' short-run needs for additional capacity.

Witness Hinton further testified that contrary to the position taken by the Public Staff in prior proceedings regarding the use of zero capacity value in certain years, he believed that in light of current circumstances related to the amount of solar generation online and pending in the interconnection queue, it is appropriate for the utilities to adjust their avoided cost rates to provide a capacity payment to new QFs only when additional capacity is needed on the system. He further stated that by restricting the inclusion of a capacity credit until the IRP has established a capacity deficiency, the risk of overpayment by ratepayers is reduced, while providing a reasonable level of financial compensation for avoided capacity costs and sending a better price signal to the market.

Witness Hinton indicated that the Public Staff supports Duke's proposal to limit capacity payments until the IRP dictates a capacity need in this proceeding, but that conditions in future proceedings may lend to reconsideration of this issue, as well as the continued applicability of the peaker method. Witness Hinton noted that DEC indicates a resource need of approximately 3,903 MWs over the planning period (2017-2031), with the first resource need in the 2022/2023 timeframe, and DEP indicates a resource need of approximately 4,071 MWs over the same planning period, with the first resource need in 2021/2022.

With regard to Dominion's position that the existing and projected level of solar generation exceeds the load in its North Carolina service territory such that there are no more capacity costs to be avoided with additional QF generation, witness Hinton testified that Dominion's proposal seems to run counter to general principles of utility system planning. Witness Hinton testified that utility planning is not performed on a state-by-state basis; rather, the generation and transmission systems are planned on a system-wide basis. This system perspective is applied in various regulatory proceedings, including IRP proceedings, where witness Hinton noted that Dominion's 2016 IRP indicates a capacity need of approximately 4,457 MW, with the first resource need in 2022. In addition, witness Hinton testified that one of the central arguments in Dominion's application to join PJM was that Dominion's membership would make the utility part of a vast integrated transmission system with interfaces with PJM-East, PJM-West, and AEP with greater access to generation resources, load diversity, and improved reserve sharing across the region. Witness Hinton disagreed with Dominion's argument that there is no capacity value associated with incremental QF generation. He therefore recommended, like DEC and DEP, that the Commission require Dominion to provide a capacity credit based on the first indicated need in its IRP.

NCSEA witness Johnson testified in opposition to the Utilities' proposal to include payments for avoided capacity only for those years when the utility's IRP shows a capacity need. Witness Johnson testified that Dominion's proposal results in the payment of no avoided capacity rate and that the DEC and DEP proposal results in an approximate 60% reduction in the avoided capacity rate from the 2014 rate. He further testified that the Commission rejected this same proposal by DEC and DEP in the 2014 biennial avoided cost proceeding, observing that: 1) DEC and DEP justified their proposal in 2014 on the same or similar bases on which they justify the 2016 proposal; and 2) that the Commission should reject the proposal again, as it did in 2014. In addition, witness Johnson testified that the use of zeros is inconsistent with the fundamental goals of PURPA, as well as the most appropriate interpretation of the concepts of "incremental cost" and "avoided cost." He also testified that the use of zeros is inconsistent with the concept of "ratepayer indifference," and it leads to undue discrimination against QFs. Witness Johnson testified that, in general, the goals of PURPA are best promoted when PURPA is implemented in a way that focuses on long run incremental cost, rather than a short run measure of cost that excludes capacity costs. More specifically, he testified that QF avoided cost rates should reflect the full long run cost of building and operating the utilities' generating facilities, including years when new generating units are not being added. He further testified that because of economies of scale, electric utilities typically find it cost effective to construct large generating facilities, at multi-year intervals. He testified that if the utility has a capacity need of 100-MW per year over a 6-year period, it will not add a 100-MW plant every year but instead will add a 600+ MW plant in a single year. Under these circumstances, Johnson argued that economic theory tells us there are long run capacity costs present in every year; they are not zero in some years and present in others. Put a different way, Johnson testified that given reality of how electric utilities add new generating capacity, even during years when "zero" capacity is planned, the long run cost of capacity is the same, or nearly the same as it is during other years, when a new block of capacity is scheduled to be placed into service. With respect to discrimination against QFs, NCSEA witness Johnson testified that PURPA specifically states that QF rates must not "discriminate against qualifying cogenerators or qualifying small power producers." He explains that under rate base regulation, the utilities are allowed to recover the cost of new generating capacity as they are completed and put into commercial operation, even though some of the capacity is being added prior to the time it is required (due to lumpiness). He testified that since the utility is allowed to recover its capacity costs during the "zero" years just after a new capacity addition and its reserve margin is higher than the required minimum, to avoid discrimination, the QF should be treated the same.

SACE witness Vitolo testified in response to the Utilities' proposal to eliminate capacity payments in years when the utility's IRP shows no need for capacity. He testified that the use of a dollar-per-kilowatt cost of a CT under the peaker methodology and the making of a capacity payment in every year are "inextricably linked." This link, he testified, results from the assumption that the utility's generating system is operating at equilibrium and that generation capacity payments will be made for all years in which the QF is in service. He further testified that the concerns expressed in the Sub 140 proceeding are still applicable today. Those concerns, he testified, prompted the Commission to reject the same proposal in the Order on Inputs. Witness Vitolo also testified in response to Dominion's proposal to eliminate capacity payments, arguing that, for similar reasons the Commission should reject this proposal as well.

As amended by HB 589, G.S. 62-156(b)(3) provides that a future capacity need shall only be avoided in a year where the utility's most recent IRP has identified a projected capacity need to serve system load and the identified need can be met by the type of resource being used by the small power producer to generate electricity.

Discussion and Conclusions

With regard to QFs that are small power producers, the Commission concludes that G.S. 62-156(b)(3) requires that, when calculating avoided capacity rates using the peaker method, a utility's standard offer to purchase should include a capacity credit for those years when the utility's most recent IRP demonstrates a need for capacity. The Commission further concludes that Duke witness Snider's proposal to provide levelized capacity payments for the full term of the ten-year standard offer, including capacity payments in years prior to the utility's first capacity need reflecting a lower annual payment to account for those initial years in which there is no avoidable capacity costs, is a reasonable means of implementing this directive. More specifically, this tends to support PURPA's directive to encourage QF development by providing more revenue to the QF earlier in the term of the standard contract. Therefore, the Commission will require the Utilities to include this methodology in their respective standard offer to purchase tariffs as part of the compliance filing required by this order.

Based upon the foregoing and the entire record herein, the Commission determines that this avoided capacity payment methodology is also appropriate with regard to the standard offer to purchase available to QFs that are not small power producers. While the Commission has previously considered and rejected similar proposals in past avoided cost proceedings, the Commission finds that the changed economic and regulatory circumstances facing QFs and utilities now justifies accepting this change. PURPA requires that QFs be fairly and reasonably compensated for the incremental capacity and energy costs that, but for the capacity and energy provided by the QF, the utility would be required to generate or purchase elsewhere to serve its customers, but PURPA was not intended to force a utility and its customers to pay for capacity that it otherwise does not need. Changes experienced in the marketplace for QF-supplied power in North Carolina challenge many of the assumptions regarding the application of the peaker method, as well as threaten to obligate customers to pay for capacity well in excess of what may actually be avoided. While the Utilities' IRPs all continue to show additional need for capacity, the mere presence of QF capacity, including solar nameplate capacity, does not always translate into an avoidance of capacity needs by the utility. FERC's regulations implementing PURPA provide that states shall 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). These factors are largely consistent with the directives in G.S. 62-156, and the Commission concludes that the operating characteristics of a QF resource must be considered in evaluating whether the QF can help to avoid the utility's planned capacity addition. In considering these characteristics and the other factors, the Commission concludes that the record in this proceeding demonstrates that the capacity value provided by additional solar PV does not necessarily help the utilities to offset or avoid their next capacity need. Solar QFs may provide some seasonal capacity benefit, but may also create other operational challenges due to its non-dispatchability and intermittency that offset the capacity benefits.

In light of these specific directives to consider dispatchability, reliability and other factors in determining avoided costs, the Commission is not persuaded by SACE witness Vitolo and NCSEA witness Johnson's arguments that inclusion of no capacity value in avoided capacity rates when the utility's IRP does not show a need is discriminatory under PURPA. As discussed in detail above, the testimony of the Utilities' and the Public Staff's witnesses demonstrates that the decision to allow a utility to add its owned generation resources to its portfolio and recover the costs is too different from the PURPA must-purchase requirement to make this a useful analogy.

However, the Commission agrees with NCSEA witness Johnson that the appropriate analysis of capacity needs should be conducted over the long run, and the use of zeroes in the early years will have the effect of lowering the avoided cost rates for the entire period. The Commission finds that this outcome may provide avoided cost rates that more accurately reflect the cost being avoided by the Utilities, in light of the amount of current and pending growth from QFs in North Carolina. As Public Staff witness Hinton testified, by including a capacity credit only in those years in which the IRP has established a capacity deficiency, the risk of overpayment by ratepayers is reduced, while providing a reasonable level of financial compensation for avoided capacity costs and sending a better price signal to the market. Further, the Commission agrees with witness Johnson that the Utilities should focus on improving the rate design in ways that are responsive to the specific concerns that have been identified to ensure that the change in policies being adopted in this proceeding do not adversely impact other small power producers, including wind, methane from landfills, hog or poultry waste, and non-animal biomass, for problems that are specifically related to solar energy. As discussed in other sections of this order, the Commission concludes that an avoided cost rate based on the characteristics of the QF-supplied power may also be appropriate going forward in future proceedings, and, therefore, will require the Utilities to include proposed rates and data sufficient for the parties and the Commission to evaluate the appropriateness of such a rate in their initial filings in the next biennial avoided cost proceeding.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 7 AND 8

The evidence supporting these findings of fact is found in the testimony of Duke witnesses Bowman and Snider; Dominion witness Petrie; Public Staff witness Hinton; NCSEA witness Johnson; and SACE witness Vitolo.

Summary of the Testimony

Duke Witness Snider testified in support of Duke's proposal to reduce the PAF multiplier for non-hydro facilities from 1.20 to 1.05 to align the PAF with the operational characteristics of a CT. Witness Snider testified that the PAF is intended to make up for a QF's unavailability during the on-peak period when QFs are paid for capacity by increasing the rate the QF is paid during peak hours to account for hours in which it does not operate. Witness Snider acknowledged that Duke's resources are sometimes unavailable, and it follows that the QFs replacing those resources should not be penalized for the same level of unavailability. He further testified that when using the peaker methodology to calculate avoided cost rates, the resource a QF is replacing is a CT. He then testified that DEC's and DEP's CT fleet performs at greater than 95% starting reliability, and as such, no PAF greater than 1.05 is warranted. Witness Snider acknowledged that the Commission declined to adopt a similar proposal in the Sub 140 proceeding, noting that the Commission determined that the arguments presented in that proceeding to modify the PAF were insufficient "at that time," and found "widespread QF development under the existing framework without adverse impacts to ratepayers." Witness Snider testified that since Sub 140, both DEC and DEP have experienced an unprecedented "surge" in solar QFs exposing customers to $1 billion in overpayments for energy and capacity. He testified that the approximately $1 billion in overpayments only accounts for QFs that are currently delivering power and does not include approximately 1,100 MW (of 5 MW and less QFs) that are in development or under construction and remain eligible for the avoided cost rates that were calculated in Sub 140 or Sub 136. He also testified that Duke is unaware of any other jurisdiction, except DEC's and DEP's stipulated avoided cost rates in South Carolina (which are derived from the rates calculated in Sub 140), that have recently explicitly or implicitly provided for a PAF multiplier in setting avoided capacity rates.

Witness Snider also responded to the Public Staff witnesses' testimony, recommending a PAF of 1.16 based on an average availability factor of 86.33%. He states that the Public Staff's focus on "availability" is appropriate, but their calculation has a critical flaw that leads to substantial overstatement of a just and reasonable PAF. In support of his argument he first defined a generator's "availability factor" as the amount of time that it is able to produce electricity over a certain period, divided by the amount of time in the period. He understands the time period used in the Public Staff's calculations based on annual data, testifying that witnesses Hinton and Metz are testifying that the average availability factor for certain DEC, DEP, and Dominion baseload and intermediate units was about 86% during the period 2011-2016. Further, wtiness Snider testified that the numerator of the availability factor reflects (i.e., is reduced by) the amount of time that a unit is out of service for planned maintenance, and, thus, the annual availability factor measures how much a unit is available across an entire year which includes these planned outages such as nuclear refueling outages. He further testified that planned maintenance is typically conducted during off-peak shoulder periods when electricity demand is low. As such, he argued that using the annual availability factor for the Companies' generating fleet is not relevant to the intended purpose of the PAF, which applies only to on-peak periods. He further stated that, by definition, off-peak periods have very low loss of load risk even with the planned maintenance outages, and that of greater importance, QFs do not have to produce a single MWh in off-peak hours to receive their full capacity payment. His criticism is that the Public Staff's use of off-peak planned maintenance from utility generation effectively increases the proposed PAF they are recommending for QFs, and testified that this would imply that an acceptable operational practice would be to schedule a nuclear unit refueling outage during peak demand periods. He testified that this is obviously not representative of prudent utility operating practice, and that, in fact, the Companies strive to take outages, planned or not, during lower load or off-peak periods when capacity is not needed. He summarized, stating that any availability metric used to support a PAF must focus solely on the peak availability and not annual availability, and that it is mathematically incorrect to base a PAF on annual availability of utility generation which includes off-peak outages as a measure of on-peak performance for a QF.

Further, witness Snider noted that utility reserve margins are based on on-peak availability of greater than 95%. He testified that imposing an assumed 86% peak availability would result in a significant increase in the Companies' reserve margin requirement and significant increase in costs to consumers to build or buy greater amounts of capacity in order to provide reliable service. In responding to witness Johnson's contention that utilities are not held to the high standard of 95% availability, witness Snider testified that Duke manages its generation fleets to achieve a very high level of on-peak reliability and does not believe the Commission would accept less. In conclusion, witness Snider testified that if the Commission believes that the PAF should be based on a system availability metric, as the Public Staff recommends, then it should be based on a metric that represents the reliability of the system during peak demand periods. Therefore, he recommended using the Equivalent Forced Outage Rate (EFOR) which represents the reliability of a unit or generating fleet during periods between planned maintenance intervals which means that it is a better indicator of the reliability of the unit or fleet during peak demand periods when performance is critical. He noted that similar to the CT starting reliability data, the EFOR data from the 2016 resource adequacy studies again supports a PAF less than, and certainly no greater than 1.05.

In addressing the characteristics of QF-supplied power, witness Snider further testified that if a solar QF, or any other QF for that matter, was truly dispatchable, then the Companies would be open to a demand rate that would allow the dispatchable QF to receive capacity payments consistent with other dispatchable capacity resources Duke purchases outside of PURPA. He noted that it is the very non-dispatchable nature of QF power that requires the QF to operate across the peak to receive a full capacity payment. Witness Snider testified that if the QF were dispatchable, capacity would be based upon dispatch performance like other generation outside of PURPA. He suggested this is a key point that is often lost in the comparison of non-QF capacity and QF capacity. According to witness Snider, PURPA specifically envisions issues like intermittency and dispatchability to be factored into the rate structure and valuation.

Dominion witness Petrie testified that, consistent with its proposal not to make a capacity payment to QFs for the duration of the standard offer contract, Dominion did not propose any adjustments to the PAF. Witness Petrie agreed, however, that the PAF issue merits reevaluation in this proceeding, and testified that, to the extent that the Commission directs the Utilities to offer capacity rates to QFs in this proceeding, a PAF of 1.05 would be appropriate. He testified that, since the peaker method determines avoided capacity costs based on the installed cost of a peaking CT unit, the peak hours availability of a peaking CT should be the basis for the PAF. He testified further that, if a QF cannot operate at a level of availability similar to or better than a CT during peak periods, and does not provide the same level of reliability as a CT, the QF should not be entitled to rates based on the avoided cost of a full CT. Specifically, he testified that if a QF is assumed to defer the need for a CT with 95% availability during peak hours, the QF should not receive the same capacity payment if it is only available 83% (or less) of the time. Witness Petrie testified that witness Johnson's testimony demonstrates precisely this distinction in availability and reliability between a solar facility and a CT. He also testified in response to witness Vitolo's assertions that the year-round availability of all fleet units is not the correct metric to use for this purpose, because it includes maintenance and planned outages that are purposely scheduled to occur during non-peak conditions. The appropriate measure for the PAF, witness Petrie concluded, is the availability of a CT during summer and winter peak hours, resulting in a PAF of 1.05. For the same reasons, witness Petrie disagreed with the Public Staff witnesses' recommendation of a 1.16 PAF.

Witness Petrie recognized that the Commission declined to accept this proposal in the 2014 biennial proceeding. He noted, however, that in making that decision, the Commission stated that there had been widespread QF development under the existing framework without adverse impacts to utility ratepayers. Witness Petrie testified that, as Dominion has shown, this is no longer true, because circumstances have changed since 2014, and utility customers are being adversely impacted.

Public Staff witness Hinton provided a brief history of the PAF, stating that in the early stages of PURPA implementation, the Commission approved a capacity credit adjustment based on the utilities' reserve margin of 20%, which was subsequently replaced with the PAF. The Commission has consistently recognized in its avoided cost orders over the years that the purpose of the PAF is to allow a QF to experience a reasonable number of outages and still receive capacity payments that the Commission had determined constituted the utility's avoided capacity costs. More specifically, according to witness Hinton, the Commission has recognized that, because standard capacity rates are paid on a per-kWh basis, setting avoided capacity rates at a level equal to a utility's avoided capacity cost without a PAF would require a QF to operate on all peak hours throughout the year in order to receive the full capacity payment to which it is entitled. Witness Hinton testified that the Commission has consistently recognized in its avoided cost orders over the years that the purpose of the PAF is to allow a QF to experience a reasonable number of outages and still receive the capacity payments that the Commission had determined constituted the utility's avoided capacity costs. More specifically, witness Hinton noted that the Commission has recognized that, because standard capacity rates are paid on a per-kWh basis, setting avoided capacity rates at a level equal to a utility's avoided capacity cost without a PAF would require a QF to operate all on-peak hours throughout the year in order to receive the full capacity payment to which it is entitled.[1] According to witness Hinton, using a 1.2 PAF allows a QF to receive the utility's full avoided capacity costs if it operates 83% of the on-peak hours. Further, witness Hinton notes that the Commission has previously concluded that the use of a 1.2 PAF reflects its judgment

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[1] See e.g., Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 127, 11-12 (2011).

that, if a QF is available 83% of the relevant time, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs.

Witness Hinton stated with respect to the argument that the starting reliability of a CT should be used to establish the PAF, the Commission has specifically rejected the use of a CT for this purpose, most recently in the Sub 140 proceeding. In that proceeding, the Commission concluded that the availability of a CT is not determinative for purposes of calculating a PAF because the fixed costs of a peaking unit are just a proxy for the capacity-related portion of the fixed costs of any avoided generating unit. Witness Hinton testified that the Public Staff agrees with the Commission's previous conclusions that if a QF's availability is similar to that of the utility's baseload fleet, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs.

Witness Metz testified that he does not agree entirely with Duke's proposal of 1.05 PAF. He testified that while he agrees that a 1.2 PAF may no longer be appropriate for use in calculating avoided cost rates, he does not agree that the appropriate PAF is the one that matches the reliability of a CT. Witness Metz noted that the peaker methodology uses a CT as a proxy for the pure capacity value of generation versus the energy value, but it is not meant to imply that all QF capacity calculations should be based on the characteristics of a CT. Witness Metz recommended that the Commission approve a PAF value of 1.16, which he notes is reflective of a broader plant availability factor average of 86.33% .

Witness Metz testified that his calculation was based upon plant performance data filed by the Utilities in monthly Commission Baseload Power Plant Performance Reports, SNL data, and responses to Public Staff data requests. He noted that when data was not available for particular units, he made assumptions based on historical performance of the unit using capacity factors. Witness Metz stated that his calculation is similar to that made by the Public Staff in prior avoided cost proceedings. Further, he noted that his calculation included intermediate generating units in addition to baseload units, as well as some operating characteristics based on known information about certain generating facilities. Witness Metz recommended that the Commission consider this revised PAF calculation based on the historic weighted availability factors of the utilities' baseload and intermediate generating units as a refinement and update to the Public Staff's previous PAF calculations.

NCSEA argues that the proposed reduction is unreasonable and should be rejected. NCSEA witness Johnson testified that under the peaker method, the fixed costs of a peaking unit are used as a proxy for the capacity-related portion of the fixed costs of all units, including baseload units and, hence, witness Johnson opined that the availability of all types of generating units (intermediate and baseload) must be considered, contrary to the narrower viewpoint initially expressed by Duke. Further, NCSEA witness Johnson testified that while the precise calculation of the PAF may be disputed, QFs must be treated in a non-discriminatory manner, consistent with the treatment afforded the electric utilities. He testified that this is important because QF rates are supposed to leave customers financially indifferent between purchases of QF power and the generation of the same amount of output by the utility. NCSEA witness Johnson further testified that reducing the PAF to 1.05 would have the effect of requiring a QF to generate at full capacity during 95% of the on-peak hours in order to receive full payment of the avoided capacity costs. Johnson testified that a solar generator would not receive full payment of the avoided capacity costs, because it is incapable of generating electricity during 95% of the on-peak hours due to the fact that many on-peak hours occur before the sun rises or after the sun sets.

Witness Vitolo argued that the Commission should reject the proposal by DEC and DEP to reduce the PAF from 1.2 to 1.05. Witness Vitolo testified that the resource the QF is replacing is not a CT. He noted that the peaker method assumes that the utility's fleet is in equilibrium and therefore "the quantitative result is not biased by the choice of one particular technology over another."[1] Further, according to witness Vitolo, the only specific role for a combustion turbine in the peaker method is to estimate the avoided capacity cost for a new unit. Witness Vitolo opines that there is no expectation that the QF will avoid the utility procurement of a specific generator technology or type. Witness Vitolo testified that in any given hour, the QF could be displacing a peaking unit, a mid-range unit, or even a baseload unit – demonstrating that the QF's availability should be compared to the utility's entire fleet. Witness Vitolo recommended that the Commission maintain current policy by requiring the Companies continue to use a 1.20 PAF for non-hydro renewable QFs. He noted that the availability standard implied by a 1.20 PAF better aligns with the expected availability of units in a utility fleet.

Discussion and Conclusions

In its Sub 100 Order, the Commission concluded that the availability of a CT is not determinative for purposes of calculating a PAF, because the fixed costs of a peaking unit are only a proxy for the capacity-related portion of the fixed cost of any avoided generating unit.[2] The Commission reiterated this conclusion in the Order on Inputs, finding that despite the widespread development of QFs, the existing framework was not resulting in adverse impacts to utility ratepayers. The parties in this proceeding agree with basic notion that a PAF is appropriately included in the avoided capacity methodology and that something other than the availability of a CT should be considered in calculating a PAF. The parties dispute what metrics should be considered in developing the appropriate PAF.

Unlike in the Sub 140 proceeding, the Commission has found in this order that the circumstances facing QFs and utilities in North Carolina have changed. As relevant to the calculation of the PAF, this change is evidenced, in part, by the Utilities' increased operation of combined-cycle (CC) units as baseload and intermediate generation, their use of coal plants as intermediate and peaking generators, as well as the Utilities' increased use of CTs. In addition, in this proceeding the parties' evidence and arguments address the appropriate PAF to be included in the avoided capacity methodology with greater precision than past proceedings.

The resolution of this issue focuses the Commission's attention on the requirement that avoided cost rates must be non-discriminatory. See Order No. 69 at 12,222-12,223. As relevant to calculating the PAF, the witnesses testified that this requires the Commission to make a fair comparison between the performance of utility-owned generation resources and QFs. The witnesses agree that the appropriate comparison should focus on generating unit "availability" and

[1] Citing, Laurence D. Kirsch, Direct Testimony on behalf of the Public Staff, Docket No. E-100, Sub 140 (April 25, 2014), Page 23, Line 6.

[2] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 100, at 22, issued September 29, 2005.

that an evaluation of availability should be based upon an informed discussion of utility system planning and load forecasting. In other words, the appropriate analysis is of the utility's broader fleet availability. The parties' dispute centers on what is the appropriate method to be used in developing the PAF for analyzing "availability" across the utility's fleet.

The Commission agrees with witness Snider that the 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. Further, as utility reserve margins are based on on-peak availability of greater than 95%, an assumed 86% availability would result in a significant increase in the Utilities' reserve margin requirements. That result would be inconsistent with the reserve margins accepted as reasonable in the Commission's recent order accepting Duke's IRPs.[1] In addition, as witness Snider testified, it follows that this approach would, on a theoretical level, contemplate the Duke utilities planning for 5,000 MW of generation unavailable during any given peak hour. As witness Snider testified, the Commission would be unlikely to find this an acceptable manner for Duke to carry out its statutory obligations to provide reliable power to its North Carolina ratepayers. For these same reasons, the Commission is not persuaded by the testimony of SACE witness Vitolo.

Rather than availability factor, the Commission agrees with witness Snider that a more reasonable approach is to develop the PAF based on equivalent forced outage rate (EFOR) for several reasons. First, this makes a fair comparison between on-peak reliability of all generation resources and a reasonable expectation of QF availability during on-peak hours. Second, EFOR represents the reliability of a unit or generating fleet during periods between planned maintenance intervals, making it a better indicator of utility generating fleet performance during the on-peak hours. Third, this avoids raising problematic issues of accepting higher reserve margins for planning based on lowering expectations of on-peak performance reliability. In this regard, use of the EFOR in calculating the PAF tends to harmonize the Commission's approach to calculating avoided capacity payments with the Commission's approach to long-term planning analysis. Fourth, Duke's uncontroverted testimony is that North Carolina is the only state that applies a pure capacity multiplier similar to a PAF. Finally, and more broadly, holding QFs to the same high performance standards during on-peak periods incentivizes efficient behavior for both utilities and QFs, and tends to support the public interest by insuring ratepayers are provided adequate, reliable, and cost-effective service.

The Commission carefully considered the testimony of NCSEA witness Johnson expressing concern with the Utilities' use of "arbitrary, overly broad, on-peak time periods" to produce the Option A and Option B rate schemes. The Commission is inclined to agree with witness Johnson that avoided capacity calculations could send better price signals to incentivize QFs to better match the generation needs of utilities, and that proper incentives could drive QFs to adopt new technologies such as solar PV that tracks the sun or incorporates storage. Therefore, the Commission will require the Utilities to consider refinements to the avoided capacity calculation as suggested by witness Johnson and to address these refinements in their initial filings in the next avoided cost proceeding. This should include consideration of a rate scheme that pays higher

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[1] See Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans, Docket No. E-100, Sub 147, issued June 27, 2017.

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.

Based upon the foregoing and the entire record herein, the Commission determines that the availability of a CT is not determinative for calculating the PAF, and that calculation of the PAF should be based on a methodology that uses a system availability metric that represents the reliability of the system during peak demand periods. The Commission concludes that a PAF of 1.05 should be utilized by DEC, DEP, and Dominion in their respective avoided cost calculations for all QFs except hydroelectric facilities without storage capability. The Commission further determines that EFOR and similarly focused equivalent availability are appropriate peak season reliability indicators. In the interest of harmonizing the Commission's avoided cost proceedings and other routine filings such as power plant performance reports, the Commission determines that equivalent availability may be the more appropriate metric. As such, the Commission will require the Utilities to address the PAF and to support their recommendations for PAF calculations based on evidence of peak season equivalent availabilities for the utility fleets in total in its initial filings in the next biennial proceeding established to review avoided cost rates.

Finally, the Commission considered issues raised in DEC and DEP filed Schedules PP-H and PPH-1, respectively, setting forth avoided cost rates available to run-of-the-river QF hydro facilities without storage capability and reflecting the terms and conditions of the Hydro Stipulation. By these schedules, DEC and DEP would continue to use a 2.0 PAF to calculate the avoided cost rates for these QFs with the same hour options that these QFs had in 2014 under DEC's Schedule PP-H and DEP's Schedule CSP-29. The Hydro Stipulation, which the Commission approved in the Order on Inputs, provides that DEC and DEP would include and incorporate the foregoing in their proposed avoided cost rates and proposed standard terms and conditions pertaining to small hydro QFs filed at the Commission until December 31, 2020.

No party introduced any evidence disputing that the avoided cost rates shown on DEC's PP-H and DEP's PPH-1 were inconsistent with the Hydro Settlement, and no party introduced any evidence indicating that the Commission should reconsider its prior approval of the Hydro Stipulation. In contrast to the Commission's implementation of the standard offer contract, the amendments to G.S. 62-2(27a) and 62-156 do not speak to the PAF. Thus, the Commission's historic reliance on this as state policy supporting the encouragement of the development and economic feasibility of small hydroelectric generating facilities is not undermined with regard to the PAF. Further, the Commission notes that there is no evidence of an alternative PAF for run-of-the-river hydro QFs in this proceeding, and the Commission finds that prudential considerations support not undoing the Hydro Stipulation at this time. Considerations of regulatory certainty lend further support to allowing the Hydro Stipulation to continue, at least through the end of the two-year period that is covered by this biennial proceeding.

Based on the foregoing and the entire record herein, the Commission finds that the 2.0 PAF included in Schedule PP-H and PPH-1 are consistent with the Hydro Stipulation and should be approved. The Commission further finds it appropriate to require the Utilities to address this issues in its initial filings in the next biennial avoided cost proceeding.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NO. 9

The evidence supporting this finding of fact is found in the testimony of Duke witness Snider, Public Staff witness Hinton, NCSEA witness Johnson, and SACE witness Vitolo.

Summary of the Testimony

Duke witness Snider testified in support of Duke's proposal to change the seasonal allocation weightings that are an input into determining the avoided capacity rates. Witness Snider testified that Duke commissioned resource adequacy studies that were presented in their 2016 IRPs. He testified that the high penetration of solar resources that have connected to Duke's transmission and distribution systems in the past 2-3 years, along with the high volume of solar resources currently in the interconnection queue, was one driver of the studies, and the significant load response to cold weather experienced in 2014-2015 winter periods was the other. Witness Snider testified that, in the past, the Companies' annual peak demands were projected to occur in summer. In addition, the Companies' generating fleets, especially gas-fired CTs and CC units, have greater output during winter periods compared to summer periods. Thus, summer load and resources have driven the timing need for new resource additions, and a summer reserve margin target provided adequate reserves in both the summer and winter periods and was sufficient for overall resource adequacy.

Witness Snider testified, however, the load and resource balance has changed dramatically in the past two to three years, driven primarily by the high penetration of solar resources and the significant load response to cold weather experienced during the 2014 and 2015 winter periods. He further testified that solar resources contribute significantly more to the summer afternoon peak than they contribute to winter morning peak. Therefore, witness Snider stated, the 2016 resource adequacy studies demonstrated that the loss of load risk is now heavily concentrated during the winter period. As such, a summer reserve margin target will no longer ensure adequate reserve capacity in the winter, and winter load and resources now drive the timing and need for new capacity additions.

Witness Snider testified that the Companies increased their minimum planning reserve margin target in the 2016 IRP due to the surging solar penetration and significant winter load response. Solar resources contribute approximately 45% of their nameplate rating at the time of the summer peak, which occurs in the afternoon hours. He noted that the Companies' winter peaks occur in the early morning hours around 7:00 am when solar has no output. The Companies' 2016 IRP reflect a 5% capacity contribution from solar for winter resource planning purposes. Thus, as solar resources increase, the Companies' summer reserve margins increase compared to winter reserves. Witness Snider testified that higher solar penetration is one of the drivers of the shift to winter capacity planning and why the Companies must now plan new resource additions to satisfy minimum winter reserve margins. Planning to a 17% winter reserve margin with growing summer resources will result in an increasing summer reserve margin over time. Witness Snider demonstrated also that the disparity will continue to grow as solar penetration increases. Witness Snider next testified that 2016 resource adequacy studies showed that approximately 80% or more of the loss of load risk now occurs during the winter period and about 20% during the summer period, and that this 80/20 winter/summer seasonal weighting was incorporated into the Companies' avoided cost rates in this proceeding.

Public Staff witness Hinton expressed concern that Duke's proposed seasonal allocation factors overly emphasized winter periods. He noted the significant winter peaks in 2014 and 2015, but said that the summer peak remained considerable and cautioned against an overemphasis on winter peaks at this time. Witness Hinton recommended that the Commission make a smaller change in the seasonal allocation factor than that proposed by Duke, to 60% winter and 40% summer, and revisit the issue once there is more information and confidence regarding the utilities' emphasis on winter planning.

NCSEA witness Johnson testified that he had reviewed DEC's and DEP's hourly load data from 2006-2015 and determined that 86.5% of the most extreme system peaks occurred from June through September, while the remaining 13.5% occurred in the winter months of December through February. He concluded that rather than shift seasonal allocation toward winter, these data support a stronger allocation toward summer. He recommended that the Commission create three sets of months: June through September; December through February; and the remaining months for allocating capacity seasonally. In the alternative, Dr. Johnson proposed that the Commission retain the current 60% summer and 40% winter allocation.

SACE witness Vitolo expressed concern about using the Astrapé studies as a basis for the seasonal allocation, as the 36 weather years (1980-2015) in the studies were developed using five years of historical weather and load data that included the polar vortex years of 2014 and 2015. Dr. Vitolo stated that this could overstate winter peaks. He also noted that the studies did not account for any investments Duke may make to meet wintertime reliability challenges. He pointed out that the Astrapé studies are for use in 2019, and do not pertain to 2017 or 2018. He recommended that the Commission assign 80% of capacity to summer and 20% to winter for 2017 and 2018.

In his rebuttal testimony, Duke witness Snider noted the differences between being winter peaking and winter planning. He testified that the shift to winter planning is driven by the impact of solar generation. He did not refute NCSEA witness Johnson's calculations of peaks based on the hourly load data, but contended that the calculations failed to consider reserve capacity. In response to the testimony of Public Staff witness Hinton, witness Snider testified that the shift to winter planning is not due to the load forecast, but due to penetration of solar resources and winter load variability. Witness Snider noted that the Astrapé studies modeled 36 weather years using the last five years' weather and load data to develop weather and load relationships. Witness Snider stated that the impact of Duke's proposed change in seasonal allocation of capacity payments to QFs would be approximately one percent, and have no effect on baseload QFs.

Discussion and Conclusions

The parties' recommended allocations for seasonal capacity range from 80% winter and 20% summer, as proposed by Duke, to 20% winter and 80% summer, as calculated by SACE witness Vitolo. The Commission determines that the evidence on this issue demonstrates that a shift toward winter peak demands and winter seasonal loss of load risk is appropriate for purposes of seasonal allocation of capacity payments in this case. These changes, which have been influenced by the increased amount of solar-powered QFs interconnected to Duke's electric systems, justify an adjustment to the seasonal capacity allocation input to calculating avoided cost rates.

The Commission finds that a high penetration of solar resources that have connected to the Companies' transmission and distribution systems in the past two to three years, along with the high volume of solar resources currently in the interconnection queue have driven Duke's resource adequacy studies; the significant load response to cold weather experienced in 2014-2015 winter periods has been the other driver. The Commission determines that for purposes of this case it is appropriate to rely on the resource adequacy studies for purposes of seasonal allocation of capacity payments.

The Commission finds that Duke's load and resource balance has changed in the past two to three years, driven primarily by the high penetration of solar resources and the significant load response to cold weather experienced during the 2014 and 2015 winter periods. Duke's solar resources contribute significantly more to the summer afternoon peak than they contribute to winter morning peak. Duke's 2016 resource adequacy studies demonstrated that the loss of load risk is now heavily concentrated during the winter period. As such, a summer reserve margin target will no longer ensure adequate reserve capacity in the winter, and winter load and resources presently drive the timing and need for new capacity additions.

The Commission finds that solar resources presently contribute approximately 45% of their nameplate rating at the time of the summer peak, which occurs in the afternoon hours. The Companies' winter peaks occur in the early morning hours around 7:00 a.m. when solar has insignificant output. The Companies' 2016 IRP reflect a 5% capacity contribution from solar for winter resource planning purposes.

Duke's 2016 resource adequacy studies showed that approximately 80% or more of the loss of load risk presently occurs during the winter period and about 20% during the summer period. The Commission determines this substantial loss of load risk justifies the 80% winter, 20% summer allocation for establishing rates in this case.

The Commission agrees that Duke's winter capacity planning is distinct from winter peaking. The impact of the addition of solar resources on that planning requires DEC and DEP to "plan" on a winter peak reserve margin criteria as a result of existing and anticipated solar on the system. Regardless of when the peaks occur, the resource adequacy studies showed a need for both Companies to shift to winter capacity planning because Duke's summer peaks occur late in the afternoon when solar has some energy contributions as compared to winter where very little solar is available at the time of peak. As a result, summer peak loads are net of solar output compared to winter peak loads.

As an alternative to Duke's proposed change, witness Hinton recommended that DEC and DEP adjust the seasonal weighting to 40% for summer and 60% for non-summer. In support of this recommendation, witness Hinton stated, "it was somewhat of an uninformed judgement call .... In the IRP, we clearly address issues with the reserve margin study and I had concerns personally with their load forecasting. ... I just felt it was appropriate not to make such a large change in the seasonal allocation until we have more information." The Commission is not persuaded that this "uninformed judgment call" justifies the allocation advanced by the Public Staff at this time for the purposes of this case. The Commission is also unpersuaded by witness Vitolo's criticisms of the Companies' resource adequacy studies regarding the use of historical weather data. Witness Snider's testimony that the resource adequacy studies not only include five years of weather and load data, as asserted by witness Vitolo, but the recent temperature and load relationships were applied to 36 historic weather years that were included in the study, sufficiently outweigh witness Vitolo's criticisms. The Commission is likewise not persuaded by witness Johnson's argument that historic summer peak load data does not support Duke's seasonal weightings. Witness Snider's testimony that high penetrations of solar have a significant impact on summer versus winter loads net of solar contributions and his testimony regarding the associated impact on reserves and loss of load risk sufficiently address the concerns expressed by witness Johnson in his testimony.

Based upon the foregoing and the entire record herein, the Commission determines that Duke's proposed seasonal allocation weightings of 80% for winter and 20% for summer are appropriate for use in weighting capacity value between winter and summer, and should be used in calculating DEC and DEP's avoided capacity rates in this proceeding. In reaching this finding, the Commission expressly reserves judgment on the parties' arguments regarding winter peaking versus winter planning and whether the reserve margins referenced herein are appropriate for the Duke utilities' integrated resource planning. <u>See</u> Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans, Docket No. E-100, Sub 147, at 14-15 and 21-23, issued June 27, 2017.

As with other determinations in this case, the issue of system planning is dynamic, and conditions may change in the future. Therefore, the Commission will be receptive to revisiting this issue in future avoided cost cases.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NO. 10

The evidence supporting these findings of fact is found in the testimony of Duke witnesses Bowman and Snider; Dominion witnesses Gaskill and Petrie; Public Staff witness Hinton; NCSEA witnesses Johnson and Strunk; Cypress Creek witness McConnell; and SACE witness Vitolo.

<u>Summary of the Testimony</u>

By its initial statement, Duke argues that DEC and DEP's customers are obligated to pay excess long-term costs due to the recent trend in declining energy markets over the past several years where actual incremental system marginal energy costs have been significantly lower than prior forecasts in earlier avoided cost filings. For non-hydroelectric QFs, Duke proposed to mitigate the longer-term commodity price forecast risk through the modified Schedule PP 10-year avoided cost rate structure that included biennially resetting avoided energy rates.

Witness Bowman testified that Duke's proposal to adjust avoided energy rates every two years was consistent with PURPA's requirement that avoided cost rates be just and reasonable to customers, in the public interest, and not discriminatory to QFs. She argues that this means avoided cost rates should not exceed the incremental costs of alternative energy that the utility would generate or purchase from another source. Witness Bowman further argued that if contracts extend for many years, the forecasted avoided cost rates become increasingly inaccurate. She noted that PURPA does not prescribe a minimum or maximum term for a "long-term" contract, and that different states offer differing terms. She contrasted South Carolina, which has a maximum 10-year fixed long-term contract, with Georgia, which has a maximum 5-year fixed long-term contract,[1] and noted that Tennessee, Alabama, and Mississippi have all approved minimum standard offer terms of one year, and that the Idaho Public Utilities Commission recently approved a two-year fixed contract term for wind and solar QFs larger than 100 kW.

Duke witness Snider also testified in support of the proposed 10-year maximum term standard contract with capacity rates fixed over the term and energy rates readjusted as part of the Commission's biennial avoided cost proceedings. He testified that approximately 1,600 MW of utility-scale QF solar generators are now interconnected and delivering power to DEC/DEP under prior Commission-approved avoided cost rates, and an additional 1,100 MW of proposed solar QFs either in development or under construction have also taken the steps required to "lock in" to the Sub 136 and Sub 140 standard avoided cost rates that the Commission previously approved. Witness Snider testified that these growing risks associated with the long-term financial obligations under existing PURPA standard offer contracts has driven Duke's proposed modifications to its Schedules PP and PP-3 rate design in this proceeding. He argues that development of these additional solar QFs inevitably means that Duke's financial obligation under PURPA and customers' exposure to overpayments could increase significantly in the future.

Witness Snider then testified that entering into long-term fixed price contracts without regard to changing commodity market conditions had caused the citizens and businesses of North Carolina to pay for QF generation at this substantially higher cost. Overpayment in energy rates to the QFs is driven primarily by the significant decline in fuel commodity prices over the last several years. Witness Snider testified that in general, 10-year levelized gas prices had fallen approximately 40% and coal prices had fallen approximately 16% for that same period as compared to those used in calculating Duke's avoided energy cost in the 2014 Sub 140 proceeding. He asserted that if energy rates were recalculated more regularly, they would better align with future fuel commodity prices. Therefore, to mitigate the potential harm to Duke's customers of long-term overpayments in excess of actual future avoided costs, Duke proposed modifications to their proposed standard offers to balance the QF's interests for fixed long-term contracts while limiting the significant fuel commodity forecast price risk for Duke's customers going forward. Witness Snider testified that adjusting energy rates at reasonable, periodic intervals throughout the duration of a long-term contract is an effective way to reduce customers' exposure to overpayments.

Witness Snider also contrasted the PPAs that Duke enters into outside of PURPA with those under PURPA. Duke's PPAs outside of PURPA generally do not include long-term commodity price risks. DEC and DEP also seek to procure energy or build new generation based on a need that is typically defined in DEC's or DEP's IRPs. When DEC or DEP solicit offers for new energy or capacity, the Commission reviews the prudence of the proposed resource options by assessing the economics and the risks with the objective of procuring the least cost, least risk assets for customers. Further, when a PPA is negotiated outside of PURPA, the energy payment terms are generally linked to a real time fuel price index, and, as such, DEC and DEP minimize

[1] The Commission notes that the Georgia Power Company's Solar Purchase Schedule SP-2 was discontinued for new customers in July 2016. Public Staff witness Hinton testified during the hearing that authorized fixed-term standard offer available in Georgia Power's service territory to QFs 100 kW or less is now two years. (Tr. Vol. 3 at 95; Tr. Vol. 8 at 143).

the risk of the customer paying beyond market energy prices. Witness Snider concluded that Duke's proposed modification to the standard offer structure better aligns the level of risk imposed upon customers in PURPA contracts with those in non-PURPA ones.

Witness Bowman further testified that Duke's proposed 10-year contract term with the 2-year avoided energy adjustment was developed in response to the concerns raised by the Public Staff and other intervenors. She testified that Duke appreciates the Public Staff's and other parties' concerns that small QFs and their potential investors require certainty in terms of the avoided cost rates to be offered to determine whether to develop a project. She noted that the FERC's PURPA regulations have long provided a method through the forecast information required to be filed with the Commission pursuant to 18 C.F.R. § 292.302 for QF investors to evaluate the utility's longer-term need for capacity and the forecasted cost of energy. As testified in Order No. 69, this data can be used by QFs and their investors in evaluating the utility's future avoided costs. Although witness Bowman testified that she was not an expert in contract terms and conditions that the financial community would deem reasonable to allow QFs to attract capital, she understood that numerous considerations, including a QF developer's balance sheet, management team experience and creditworthiness, as well as avoided cost-specific considerations including price, contract tenor, the cost of capital, all come into play in determining whether an investment can attract debt and/or equity capital. PURPA largely exempts QFs from state regulatory authority over their rates and business operations so that neither Duke, the Public Staff, nor the Commission has any clear insights into a QF developer's business or the level of profit deemed reasonable to attract equity capital.

Witness Bowman also disputed testimony from intervenors that the Windham decision prohibited Duke's proposed 2-year updates of avoided energy rates in an otherwise fixed 10-year PPA. She agreed that the FERC found in Windham that PURPA's directive to encourage QFs suggests that a LEO should be sufficiently long to allow QFs reasonable opportunities to attract capital from potential investors. Witness Bowman argued, however, that Windham arose in the context of rates offered by a Connecticut utility in the ISO-New England organized market and, further, that the FERC did not specify a particular number of years for such LEOs, leaving the proper term to the discretion of the State Commissions. She noted that Alabama was the only jurisdiction outside of an organized wholesale market to consider the FERC's recent Windham decision in setting forecasted avoided cost rates under PURPA. Further, she testified that in early March 2017, the Alabama Public Service Commission (Alabama PSC) approved Alabama Power Company's (Alabama Power) standard rate offer for QFs with a design capacity above 100 kW, which offers Alabama Power's forecasted energy and capacity rate over a one-year term with an "evergreen provision" under which avoided cost pricing updates annually consistent with the updated avoided energy pricing submitted by Alabama Power.[1] The Alabama PSC held that the rate structure was consistent with PURPA and with prior FERC guidance that a long-term contract is one year or longer under PURPA.[2] Witness Bowman testified that she is unaware of any state in the Southeast with a contract term of more than 10 years under PURPA. For these reasons,

[1] Alabama Power Company, Petition for Approval of Rate CPE – Contract for Purchased Energy, Docket No. U-5213 (March 7, 2017).

[2] Id.

witness Bowman testified that Windham should not materially change the Commission's analysis of Duke's proposed standard offer structure.

Witness Bowman also disputed witness Vitolo's assertion that the Commission had previously denied a similar biennial reset of the avoided energy rate for Dominion in the 2010 Sub 127 avoided cost proceeding on the ground it was inconsistent with the FERC's J.D. Wind Orders. Witness Bowman asserted that Duke's proposal in this proceeding was in response to the current economic and regulatory circumstances. She also noted that Dominion had used the biennial reset method from 1989 to 2010 prior to the Commission directing it to transition to fixed, levelized avoided energy rates. Additionally, witness Bowman disagreed that PURPA or the FERC's regulations prohibited such a biennial reset, and noted that the Commission had allowed Dominion to offer its 2-year fixed energy rate during 2010-2011. Finally, she testified that prohibiting this option perpetuates North Carolina's status as an outlier that significantly encourages QF development compared to other southeastern states, such as Alabama, Arkansas, Florida, Kentucky, Louisiana, Maryland, and Virginia. Witness Bowman cited NCSEA witness Johnson's testimony that these states offer shorter-term variable rates, rather than fixed, long-term rates.

Witness Bowman also disputed SACE witness Vitolo's claim that QF fixed contracts should match the recovery period of Duke's own PV and other generating assets. She distinguished QF contracts from utility-owned ones in multiple ways. First, utility resource additions are driven by need, which the Utilities establish through an extensive IRP and CPCN application process. In contrast, the PURPA must-purchase requirement mandates QFs be reimbursed for selling power to Duke whether or not the power is needed. Next, witness Bowman noted that utility load-following generator resources are dispatchable. She also testified that because the Utilities were not locked into long-term fixed contracts, they can pass lower fuel and other operating cost savings to customers. A utility, however, cannot dispatch or back down a QF when more economic alternatives are available, so she argues that customers ultimately pay for potentially higher-cost QF energy produced by a QF. Long-term contracts exacerbate this inefficiency. She testified that QFs do not actually advocate for a longer cost recovery period based upon actually recovering their cost of service, but only to extend the period of guaranteed revenue (and profit) out into the future.

Dominion Witness Gaskill also responded to witness Vitolo's concern that QF solar projects are treated differently than utility projects because utility-sponsored projects depreciate capital over their lives. Witness Gaskill noted several differences between rate regulated utilities and QFs with respect to how they are organized, regulated, financed, and how they obtain cost recovery. Utilities operate under cost-of-service rate recovery, which differs significantly from how independent power producers, like QFs, recover their costs. If a utility builds a solar facility and places it into rate base, all of the benefits, including fuel savings, revenue from renewable energy credits (RECs), and investment tax credits are passed on to customers. Witness Gaskill contrasted this with QFs, which are paid the marginal costs for both capacity and energy and retain all other revenue streams from RECs and tax credits.

Witness Snider agreed that Public Staff witness Hinton's suggestion to link available energy rates to a publicly available composite fuel index was a reasonable alternative to the 2-year reset of energy payments. He argued that this accomplished the goal of minimizing the risk of overpaying QFs for the energy that they provide. Witness Snider agreed to further evaluate incorporating this proposal in its rate design in the next biennial proceeding. As an interim measure, however, and in response to specific concerns raised by the intervenors that the 2-year update to energy rates was too risky and unpredictable for QFs 1 MW and less to obtain financing, witnesses Bowman and Snider offered a "compromise proposal" in their rebuttal testimony. The compromise proposal would allow QF developers the option to "fix" the underlying 2-year avoided energy rate filed with the Schedules PP for the duration of the 10-year contract. Witness Snider noted that the 2-year fixed Schedule PP annualized energy rates were only slightly below the fixed 10-year Schedule PP-H annualized energy rates. He viewed this as an acceptable, albeit imperfect, allocation of longer term risk forecast between QFs and Duke's customers at this time. Additionally, he testified that Duke viewed this compromise offer as an interim rate design to be considered with the Public Staff's other alternative options, such as linking avoided energy rates to a fuel index, in the next biennial proceeding.

Public Staff witness Hinton testified that Dominion's proposal to provide fixed ten-year energy prices as part of its standard offer rates is reasonable and consistent with PURPA's goals of encouraging QFs. He noted that in Windham the FERC recently elaborated on this requirement more fully, as follows:

> [T]he Commission has long held that its regulations pertaining to legally enforceable obligations "are intended to reconcile the requirement that the rates for purchases equal to the utilities' avoided cost with the need for qualifying facilities to be able to enter into contractual commitments, by necessity, on estimates of future avoided costs" and has explicitly agreed with previous commenters that "stressed the need for certainty with regard to return on investment in new technologies." Given this "need for certainty with regard to return on investment," coupled with Congress' directive that the Commission "encourage" QFs, a legally enforceable obligation should be long enough to allow QFs reasonable opportunities to attract capital from potential investors.[1]

Witness Hinton testified that he does not think offering a standard offer contract with a two-year reset on the avoided energy rates would provide sufficient "certainty with regard to return on investment" to provide a QF with a reasonable opportunity "to attract capital from potential investors." He noted that larger facilities may be able to negotiate for different terms and degrees of certainty with regard to securing capital and return on investment, but that resetting energy rates every two years for facilities eligible for the standard offer rates adds an additional element of uncertainty to their ability to reasonably forecast their anticipated revenue, which could make obtaining financing difficult or impossible.

Witness Hinton acknowledged, as noted by Duke witness Bowman, that Georgia Power offers fixed two-year energy rates and only pays for avoided capacity when the IRP shows a need, similar to Duke's proposal. However, witness Hinton noted that there is little QF development in the states that offer two-year energy rates, and that the development in those states is largely in response to legislative mandates for solar power. Witness Hinton agreed that QF contracts contain risks that are ultimately borne by the utility customer. However, he further testified that these risks

[1] T. Vol. 8, p. 75, citing Windham at 8.

need to be viewed in the context of a utility's long-term commitment to build plants, whereby such decisions as the building of Cliffside Unit 6 and the Richmond County CC units were based upon forecasts that are also uncertain, resulting in ratepayers bearing the same type of forecast risk from utility plants as they do from QFs.

Witness Hinton described other options to reduce forecast risk that might be considered, such as linking available energy rates to a publicly available composite fuel index or establishing a band or collar on the amount of adjustment that energy rates could vary from some indicative pricing. He stated that these options may provide QFs with additional certainty, while reducing ratepayers' risk of overpayment. Lastly, witness Hinton noted that the Public Staff was already proposing a number of other adjustments to the rate and terms under the standard offer in this docket that would more appropriately reduce the risk of overpayment by customers.

NCSEA argues that Duke's proposed two-year reset of avoided energy rates results in disruptive uncertainty and links the future revenue stream – which is critical to the economics and financing of a QF -- to the future course of volatile fuel prices and other variables that are unknowable and unpredictable from the perspective of the QF and their investors, likely discouraging investment in QFs. NCSEA witness Strunk testified that providing fixed prices for a term that is sufficient to provide a reasonable amortization of sunk investment costs for a long-lived asset has been key to the financing of new independent power production facilities. He testified that reducing the PPA term and including two-year energy price resets would raise the price that a QF requires to be viable for two reasons: (1) the QF's cost of capital will increase as its investors bear more risk; and (2) investors will seek shorter amortization periods for capital investments, which in turn translate to higher short-term cash flow requirements. He stated that reducing the term of the PPA therefore increases the near-term costs for the QF, decreases the possibility that those costs could be recovered under avoided cost pricing, and reduces the likelihood that the facility will actually be developed. This reduction of the time period over which fixed rates apply will lead lenders to view the effective PPA coverage period as only two years, even though Duke is proposing a 10-year PPA term. He indicated that lenders will significantly discount the revenues available beyond that two-year period, and as a result, it is unlikely that project debt could be obtained in reasonable quantities for terms longer than two years.

NCSEA witness Johnson testified that under the current avoided cost tariff structure in North Carolina, a QF benefits from a fixed revenue stream that aligns well with its fixed costs, but under DEC's and DEP's proposal to provide for a two-year reset, avoided energy rates will suddenly become highly unpredictable. He testified that "not only will the future revenue stream depend on the future course of volatile fuel prices, but it will fluctuate with those prices in ways that are fundamentally unknowable and unpredictable from the perspective of the QF and their financiers, because it will depend on the outcome of litigated proceedings every two years." Witness Johnson testified that most non-PURPA sellers of power are burning fuel, so their use of a pricing structure that recognizes fuel price changes is appropriate. He noted, however, that this approach shifts the fuel price risk to the customer. Witness Johnson testified that he did not think it was reasonable to apply a similar pricing arrangement to generators that do not consume fuel.

Cypress Creek argues that financing parties would view a ten-year PPA with a two-year readjustment to the avoided energy rate no more favorably than they would a two-year contract, which would not be financeable. Cypress Creek witness McConnell testified that rates fixed over the term of the contract are critical to securing financing, stating that "fixed rates for a fixed period of time create financeable contracts," and that what creates value in the contract is having a set avoided cost rate for a set period of time. He further testified that without these fixed rates, lenders are unwilling to bet on what the avoided cost rates will be going forward. Witness McConnell also testified that in a regulated market, a 10-year contract with a two-year reset for energy prices would be viewed as more or less equivalent to a two-year contract, and would likely not be financeable in the current environment.

SACE witness Vitolo testified that Duke's proposed change in the energy payment schedule is not appropriate since the lack of set avoided energy payments over the life of the contract would jeopardize project financing and likely discourage QF development contrary to the policy goals of PURPA. He also noted that this change would reduce the rate stability provided by decoupling some generation from variable fuel prices. He testified that in J.D. Wind FERC held that QFs are entitled to receive long-term avoided contracts or other legally enforceable obligations "with rates determined at the time the obligation is incurred, even if the avoided costs at the time of delivery ultimately differ from those calculated at the time the obligation is originally incurred." Witness Vitolo further testified that changing the payment every two years would differ significantly from how the utilities treat their own assets. He argues that a utility decision to build or purchase a generating asset nearly always includes a long-term obligation to pay for that capital asset, and that integrated resource planning and decisions to invest capital in new generators are also substantially influenced by long-term forecasts of costs, particularly fuel. In support of his argument, he noted that in the Order on Inputs, the Commission observed:

> While witness Snider's emphases that QF contracts represent long-term fixed price obligations on behalf of DEC'S and DEP's customers based largely on forecasts of future fuel prices, the Commission recognizes that a utility's commitment to build a plant represents a similar type of long-term fixed obligation for the utility's customers, largely based upon forecasts of future prices. In many respects the utilities own self-build options are based upon similar "uncertain" forecasts. Order on Inputs at p. 20.

Dr. Vitolo also discussed the Commission's Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, issued on July 27, 2011, in Docket No. E-100, Sub 127, stating that the Commission rejected Dominion's proposal to continue to offer variable avoided energy rates for QFs larger than 100 kW that would be updated every two years. The Commission determined that an avoided energy rate that "is reset every two years clearly does not qualify as either a fixed rate or as a fixed formula rate," and required the utility to begin offering fixed long-term, levelized avoided energy rates for QFs entitled to standard contracts in the following biennial proceeding.

Discussion and Conclusions

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. See Order on Inputs at p. 19-20. In addition, G.S. 62-133.8(d) provides that the terms of any contract entered into between an electric power supplier and a new solar electric facility

"... shall be of sufficient length to stimulate development of solar energy." See id. at 20. 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. Windham at 3-4. 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.

The Commission agrees with Duke witness Snider that PURPA does not require the Commission to establish avoided cost rates at levels high enough to attract financing; rather, the avoided cost rate must be equal to the avoided costs. However, the question of whether Duke's proposed two-year reset in avoided energy rates complies with PURPA is a question as to the form in which the rates are offered, not the appropriate level of the rate.

The Commission determines, for purposes of this case, that Duke's proposed two-year reset in the avoided energy rate component of the standard offer rate should not be adopted at this time. While some larger facilities may be able to negotiate for different terms and degrees of certainty with regard to securing capital and return on investment, the proposed two-year energy rate reset for facilities eligible for the standard offer rates adds an additional element of uncertainty to their ability to reasonably forecast their anticipated revenue, which may make obtaining financing more difficult than a longer term, fixed-rate PPA.

The Commission notes that in addition to providing the basis for electric power purchases from QFs by a utility, the Commission-determined avoided costs are utilized in, among other applications, the determination of the cost effectiveness of DSM/EE programs and the calculation of the performance incentives for such programs, the determination of the incremental costs of compliance with REPS for cost recovery purposes; and in some ratemaking, such as determination of stand-by rates. In these contexts, it is appropriate for the rates to be reflective of the utilities' actual forecasted rates over a longer term, not based on a short-term forecast that is fixed for the duration of a longer term.

The Commission recognizes that the parties have raised the concept of linking the avoided energy rate fuel cost component to a published composite index or establishing a band or collar on the adjustment amount. The Commission determines that this concept deserves additional study in a future proceeding. This concept tends to provide additional certainty to QFs, while mitigating the risk of inaccurate avoided energy rates in the future. Thus, the Commission will allow the Utilities to propose this change in a future biennial avoided cost proceeding, provided that the proposal includes sufficient supporting information and otherwise demonstrates compliance with PURPA's requirements.

Based upon the foregoing and the entire record herein, the Commission finds that Duke's proposal to adjust avoided energy rates every two years should not be adopted in this case. Instead, the Commission finds Dominion's proposal to provide fixed ten-year energy prices as part of its standard offer rates is reasonable and consistent with PURPA's goals of encouraging QFs. Therefore, the Commission will require Duke to file revised avoided cost rate schedules, power purchase agreements, and terms and conditions, reflective of this conclusion, as part of the compliance filing required by this order.

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

The evidence supporting these findings of fact is found in the testimonies of Duke witness Snider, Dominion witness Petrie, Public Staff witness Hinton, and NCSEA witness Johnson.

Summary of the Testimony

As a method to mitigate longer-term commodity price forecast risk, Duke proposes to modify its Schedule PP 10-year avoided cost rate to include avoided energy rates that are reset every two years based on the avoided energy cost methodology and inputs approved in the Commission's biennial avoided cost proceedings. As reflected in the preceding section, the Commission concludes that it is inappropriate to approve this proposal in this proceeding. This leaves unresolved the question of what fuel forecast is appropriately included in the Utilities' calculation of avoided energy costs as an input to its 10-year, fixed avoided energy rate.

Duke witness Snider testified that, for purposes of calculating longer-term avoided energy rates, Duke relied upon 10 years of forward market natural gas pricing data followed by a transition to Duke's fundamental natural gas forecast of spot prices in year 11. He testified that this methodology is consistent with Duke's approach to forecasting future natural gas commodity prices in DEC and DEP's respective 2016 IRPs filed on September 1, 2016, in Docket No. E-100, Sub 147. Witness Snider responded to the testimony of Public Staff witness Hinton and NCSEA witness Johnson, who both recommended that the Commission require Duke to rely more heavily upon fundamental forecast data in setting DEC's and DEP's Schedule PP-H rates.[1] He first provided context for Duke's more recent reliance on natural gas forward market data, testifying that by 2014, changes in the United States natural gas markets and the rapid increase in natural gas production due to technology advancements had created longer range options for purchasing natural gas. At this time, Duke began requesting quotes for 10-year purchases of natural gas forwards from various brokerage firms based upon these longer range forward market options. Since the Sub 140 proceeding in 2014, Duke developed its 2015 IRP updates and 2016 biennial IRPs based upon 10 years of forward market price data transitioning to fundamental forecast-derived data in year 11.

Witness Snider then testified regarding the historic 10-year levelized natural gas forecast assumptions from Duke IRPs and avoided cost proceedings dating back to 2012 to show that prices had dropped 40% since 2012, and to show how fundamental price forecasts were lagging the market prices in response to the recent structural changes in the natural gas market. He testified that fundamental forecasts take significant time to develop and are often only released by research firms once or twice per year; therefore, fundamental forecast data can be well over a year old by the time avoided cost rates go into effect. Witness Snider then emphasized the significant impact

[1] By necessity of Duke's proposal to reset avoided energy costs every two years, Duke did not propose a long term forecast input as a component of its other rate schedules. Therefore, in this section, reference is made the Schedule PP-H because that is the only rate schedule where Duke proposed a long-term fixed rate. For purposes of discussion, the Commission assumes that had Duke proposed a fixed rate under the other schedules, it would have included a similar input. Similarly, as the Commission has found a 10-year fixed rate to be an appropriate term for the standard offer contract, discussion of the proposed 15-year term under Schedule PP-H will, by necessity, serve for the purposes of discussion of this issue, but the conclusions reached in this section apply equally to Duke's other rate schedules.

that relying on stale or lagging natural gas fundamental forecast data can have on forecasted avoided costs in this proceeding, pointing out that Duke's fundamental forecast natural gas price estimates are at least $1.00/MMBtu higher than the actual market prices starting in 2020. Witness Snider also testified that the Commission's mandate in Sub 140, requiring Duke to rely upon fundamental natural gas commodity price data after year five of the long-term avoided costs rates has been the main driver along with the continuing decline in natural gas commodity prices of the current disconnect between Duke's current actual marginal system operating costs and the significantly higher avoided energy rates approved in the Phase II Order proceeding that became effective in March 2016.

Witness Snider also responded to witnesses Hinton and Johnson's arguments regarding forward markets lacking liquidity 10 years into the future. He testified that market liquidity is demonstrated by Duke having recently completed a 10-year purchased forward gas contract, executed April 5, 2017, for 2,500 MMBtu/day of natural gas forwards through 2026. He testified to his experience that long-dated forward contracts are liquid and transactable and may be purchased over-the-counter directly with large financial institutions and other firms rather than traded on the NYMEX. Witness Snider also testified that this forward market transaction provides a tangible price point for the natural gas market over the equivalent period of the 10-year PP-H hydro rate, and that the 10-year levelized price of this purchased gas is approximately 6% lower than the forward market prices used in establishing Duke's November 2016 proposed avoided cost rate and approximately 20% lower than the 5-year market plus 5-year fundamental forecast blend of 10-year prices recommended by Public Staff witness Hinton.

Witness Snider also testified that he disagreed with witness Hinton's assertion that reliance upon fundamental forecast data is more appropriate than use of actual market prices. He testified that QF purchase power transactions similarly represent significant forward purchased power obligations on behalf of customers, totaling more than $3 billion dollars today. Duke may either purchase fuel or purchase power, or both, to satisfy future customer energy needs, and PURPA requires customers to be held indifferent between the two. Witness Snider testified that use of fundamental price forecasts, rather than a transactable gas price, leads to avoided energy rates that are inconsistent with this indifference standard that is a bedrock principle of PURPA. Witness Snider also testified that, consistent with the Commission's prior direction in the Sub 140 Phase II Order, Duke's fuel forecasting methodology of using 10 years of forward market data with a blending to fundamentals starting in year 11 is the same methodology used in both the 2015 IRP and 2016 IRP filings for DEC and DEP. Third, witness Snider also testified that witness Hinton's recommendation to rely upon fundamental forecast data was in conflict with witness Hinton's own alternative recommendation to consider offering QFs avoided energy rates based on a composite commodity price index. He testified that the gas commodity price index is a market-based price, and a QF's ability to enter into a hedging transaction to fix their future revenues under this structure could only occur at the prevailing forward market price for natural gas and not at fundamental forecast-derived price levels that are different from the market price. Witness Snider testified that by offering QFs a transactable forward price above the prevailing natural gas market, the implicit result of witness Hinton's position would be to subsidize QFs while transferring significant price risk to North Carolina consumers.

Witness Snider also addressed witness Hinton's assertion that Duke and Dominion's fundamental forecasts were more comparable than Duke's reliance on 10 years of market prices.

Witness Snider testified that at any point in time only a single forward market exists for natural gas, while a wide range of fundamental price forecasts are available, as shown by the deviation between Duke's and Dominion's fundamental forecasts. During the hearing, witness Snider testified to the difference between a transactable market-based forward price versus a longer-term spot forecast of commodity price beyond the liquid market. He testified that accuracy and appropriateness were key considerations that support relying upon forward market price data in a transactable market versus fundamental forecast spot pricing. With regard to accuracy, witness Snider emphasized that only a single transactable market price exists while multiple spot forecast prices may exist based upon differing fundamental forecasts. Further, reliance on lagging or "stale" fundamental forecast pricing has proven to be inaccurate over the past few years and has led to a systematic overpayment to QFs. He testified that Duke had also addressed liquidity concerns with Duke's use of long-term forward commodity price quotes, as raised in Sub 140, by actually transacting in the forward market to accurately show the actual 10-year forward market price of natural gas. With regard to appropriateness, witness Snider testified that fundamental forecasts are intended to act as a guide to future spot prices beyond the liquid transactable curve, but are never intended to be used as a transactable price in the presence of a transactable market. He also testified how relying on higher fundamental forecast prices when a demonstrated liquid market exists can lead to arbitrage of the market prices and result in QF generators flocking to a region to take advantage.

Witness Snider also testified that contracting for QF power is also a forward market transaction committing the utility to purchase from a QF at a fixed price years into the future, and that the utility can either buy the power or buy the commodity and should be indifferent between the two. DEP's recent natural gas forward transaction procured equivalent gas to approximately 50 MW of solar QF generation at a six percent lower levelized price than the forward market commodity price used in Duke's rates filed in November. Witness Snider also identified that PURPA allows the QF the option to select pricing at the time energy is delivered if the QF believes the future spot price will be higher than the transactable forward market.

During examination by Public Staff, witness Snider agreed that NYMEX and the Intercontinental Exchange are exchange markets where shorter term natural gas futures are traded. However, he testified that the commodity market has evolved where long-dated future natural gas trading is occurring through bilateral transactions with numerous financial institutions, and Duke's experience is that a very liquid, long-dated market exists where quotes and transactions with multiple counter-parties can occur at a market price 10 years into the future. Witness Snider testified that Duke's continued and consistent reliance on 10 years of forward market data in their last four regulatory filings, including IRP and biennial avoided cost filings, as well as the April 5, 2017 10-year forward market transaction has demonstrably demonstrated a liquid and transactable market.

Dominion witness Petrie described the methodology used to calculate avoided energy cost rates under its proposed Schedule 19-FP and Schedule 19-LMP. Witness Petrie testified that the avoided energy cost rates proposed in this case for its Schedule 19-FP were calculated using the peaker method, and that, as in previous proceedings and discussed above, energy rates under Schedule 19-LMP are based on the hourly PJM DOM Zone Day-Ahead LMP expressed in dollars per MWh. He described the peaker method as it applies to energy as determining avoided energy costs based on the forecasted marginal energy costs of the system in each hour. Witness Petrie testified that Dominion uses the PROMOD production cost model to derive avoided energy cost rates for Schedule 19-FP, with those rates reflecting an adjustment to reflect the locational value of energy in Dominion's North Carolina service area where QFs are located, plus a fuel hedging benefit. He stated that Dominion uses the PROMOD output results to calculate the levelized on-peak and off-peak long-term fixed energy rates for the various contract durations under Schedule 19-FP.

Witness Petrie also testified that, consistent with Commission directives issued in the 2014 biennial proceeding, as well as with the price forecasting methodology contained in its 2016 and prior IRPs, for purposes of determining avoided energy costs in this proceeding Dominion maintained its approach of using estimated forward market prices for fuel, PJM power, and emission allowance for the first 18 months of the forecast period, a blend of forward market prices and ICF commodity price forecast as of early October 2016 for the next 18 months, and exclusively ICF commodity price forecast for the remainder of the term (starting in October 2019). He stated that this approach is consistent with the directive of the Commission's Phase 2 Order issued in the 2014 biennial proceeding that the Utilities calculate avoided energy rates using commodity forecasts constructed in a manner consistent with their IRPs. He clarified that the order did not require that the same price forecast itself must be used.

Witness Petrie testified that in determining the rates it is proposing in this case, Dominion used the same Black-Scholes Model option pricing method to determine fuel hedging benefits that was proposed by the Public Staff in the 2014 biennial proceeding. He also noted that, while Dominion believes there are likely costs associated with integration of distributed solar generation, it did not include solar integration costs in its production cost modeling. Witness Petrie noted the Public Staff's support for Dominion's fuel price forecasting approach, and disagreed with witness Johnson's suggestion that Dominion should use either the 2017 Energy Information Administration (EIA) forecast or the fundamental commodities forecast used to prepare its 2016 IRP for purposes of this case. He testified that, because the commodity prices for the 2016 IRP were developed by ICF in December 2015, Dominion used updated, October 2016 data for fuel and power prices in preparing its initial filing. He noted that, as standard offer prices are updated only every two years, QFs that establish an LEO late in the biennial period receive avoided cost rates that can be several years old by the time they commence operations, and that witness Johnson's proposal that Dominion base its avoided energy rates on forecasts that are an additional year older should, therefore, be rejected because it would exacerbate this disparity between contracted rates and actual avoided costs. Witness Petrie advised that using the 2017 EIA forecast for this purpose would also be inappropriate, as it would directly contradict the Commission's directives in the 2014 biennial proceeding and Dominion's use of ICF-developed prices for its IRP and avoided cost purposes in compliance with those directives.

Witness Petrie also testified that witness Johnson's long-term natural gas price trend line does not reflect current natural gas market fundamentals, and that it appears to discount the fact that technology improvements continue to create production benefits resulting in reduced long-term natural gas prices. He testified that witness Johnson's gas price data lends too much weight to the years 1990-2008 when natural gas prices were rising and not enough weight to the downward trend in prices from 2009-2016.

In response to witness Vitolo, witness Petrie testified that no generator is available 100% of the time, regardless of whether the unit is utility-owned and regardless of the type of energy source. He testified further that Dominion's assumption of 85% availability in calculating standard offer avoided energy rates reflects the availability of a baseload unit, and that this approach is consistent with the theory behind the peaker method as it pertains to the calculation of avoided system energy costs from a typical QF. He cited the Commission's statement in the 2004 avoided cost proceeding that the peaker method theory is that, if the utility's generating system is operating at equilibrium (that is, at the optimal point), the cost of a peaker (a combustion turbine or CT) plus the marginal running costs of the system will produce the utility's avoided cost, and that it will also equal the cost of a baseload plant. He noted that this modeling approach has been used by Dominion and accepted by the Commission for many years, including in the previous biennial proceeding.

Witness Petrie also disagreed with witness Vitolo's apparent concern that Dominion may be under estimating the energy rates due to a mismatch between the PROMOD modelling and the energy rate calculation. Witness Petrie clarified that Dominion correctly divided the total dollar savings produced by the model by 744,600 MWh, consistent with the 85% availability, and that the system cost savings in the numerator was, therefore, consistent with the QF energy production in the denominator.

On cross examination by SACE, witness Petrie agreed that in using the PROMOD model to calculate avoided energy costs, Dominion modeled the "with QF" scenario using a 100-MW generator with zero production costs, and ran this scenario assuming some outages. He testified that when the 100-MW block of energy is added, the model shows how much the production cost declines by adding that block. He testified the block has 85% availability and that the 15% unavailability is spread evenly throughout all hours of the year, including on- and off-peak hours. He also confirmed his response to a discovery request that reiterated this explanation.

Public Staff witness Hinton testified that he reviewed the coal and natural gas price forecasts used by the utilities and found most of the inputs to be reasonable, except for Duke's use of ten-year forward prices to develop its price forecast for natural gas. Witness Hinton testified that these concerns were similar to those expressed by the Public Staff in the 2014 proceeding and in the 2016 IRP regarding DEC's and DEP's over-reliance on long-term forward prices for their fuel forecasts. Witness Hinton testified that in their 2014 IRPs, DEC and DEP incorporated five years or less of forward price data before transitioning their fuel forecast to a long-term fundamental natural gas price forecast. In their 2015 IRP updates, however, they made changes to this approach by extending the period on which they relied on forward price data to ten years. Witness Hinton testified that the Public Staff and other parties advocated in the 2014 Proceeding that DEC and DEP return to their previous use of forward prices for no more than five years of the forecast before transitioning to a fundamental forecast developed by energy economists and gas analysts who estimate the future demand and supply of natural gas. Witness Hinton illustrated the difference between DEC's and DEP's previous use of five years of forward prices by graphically contrasting DEC's natural gas price forecasts incorporated in the 2012 and 2014 IRPs with DEC's gas price forecast using ten years of forward prices that were initially proposed but ultimately rejected by the Commission. In addition, witness Hinton indicated that comparing Dominion's forecast from 2017 to 2031 with that of DEC and DEP, as well as noting the similarity in their predicted fuel prices in 2031, illustrates the impacts that result from the use of forward prices over the planning period.

Witness Hinton further testified that in its Phase II Order, the Commission ordered DEC and DEP to recalculate their avoided energy rates using natural gas and coal price forecasts constructed in a consistent manner with those utilized in their 2014 IRPs. Further, the Commission found that to the extent the utilities wished to adjust the way in which they utilize forward prices and long-term forecasts in future IRP and avoided cost proceedings, that those changes should first be proposed and approved as part of the biennial IRP proceeding before being incorporated in avoided cost calculations. Witness Hinton stated, however, that DEC and DEP's proposed avoided cost rates in this proceeding again used ten years of forward prices and then shift to their traditional fundamental forecast for years 11 through 15.

Witness Hinton testified that the Public Staff supports the use of forward prices as a component in the development of a long-term price forecast. He asserted that the use for up to five years is reasonable and appropriate because the market for these contracts is relatively liquid. With regard to ten-year futures, however, witness Hinton indicated that the market is relatively illiquid, meaning the number of natural gas price investors willing to make buy and sell decisions on future prices beyond five years out in the future is much smaller and less transparent. Witness Hinton further testified that fundamental price forecasts and forward price-based forecasts are different and have different applications. In addition, he testified that traders in futures are more likely to respond to temporary conditions, as compared to fundamental price forecasts that are based on future demand and supply conditions, providing a more measured response to expected changes in the natural gas market.

Witness Hinton testified that DEC and DEP did not use the same methodology for forecasting natural gas prices in their avoided energy calculations as was used in their 2014 IRPs, or the same methodology approved by the Commission in the 2014 proceeding. He noted that in the Order on Inputs, the Commission emphasized the relationship between the generation expansion plan developed in the IRP and the determination of avoided energy costs that reflect current and future generation units combined with future renewable generation, demand-side management, and energy efficiency resources. In Phase Two, the Public Staff recommended the use of up to five years of forward prices in combination with a long-term price forecast, and the Commission ordered DEC and DEP to incorporate the natural gas price forecasts that are constructed in a consistent manner with the forecasts utilized in their 2014 IRPs. The Public Staff restated its view that an overreliance on forward price data can call into question the reasonableness of the long-term forecasts.

Witness Hinton testified that he found Dominion's reliance on forecasts from ICF International, Inc. (ICF), the same source utilized for its 2016 IRP, along with Dominion's use of three-year forward prices before transitioning to a fundamental price forecast, to be reasonable. He disagreed, however, with Duke's use of ten-year forward prices, and instead, recommended that the Commission direct DEC and DEP to recalculate their avoided energy rates using no more than five years of forward natural gas prices before transitioning to their long-term fundamental price forecast. He stated that this approach would be consistent with the Commission's directive in the 2014 proceeding that DEC and DEP utilize natural gas price forecasts that are constructed in the same manner as the forecasts utilized in their 2014 IRPs, and is also consistent with the Public Staff's comments in the 2016 IRP proceeding.

NCSEA argues that Duke's overreliance on forward market data is not reasonable. In addition, NCSEA argues that Dominion used unreasonably low fuel prices in constructing its fuel forecast for this proceeding, as compared to the fuel prices used in its 2016 IRP forecast. In support of its position, NCSEA witness Johnson testified that Duke goes to considerable effort and expense to develop its own, comprehensive, fundamental forecast of the entire US energy sector, which it updates periodically for use by both the parent and its subsidiaries. This proprietary forecast reflects Duke's view of the long-term outlook for the energy sector, which it uses to make long-term investment decisions by all of its electric utilities. Witness Johnson testified that forward market data is useful for short term forecasts, because it can easily and frequently be updated, as commodities traders respond to changes in the weather and minute-by-minute and day-to-day changes in supply and demand conditions in the commodities markets. In essence, he argues, forward market data is particularly useful for dealing with, and hedging against, fluctuations in commodity prices over the near-term future, but, it is not as useful, nor as appropriate, to use it for long-term planning purposes. Witness Johnson further testified that fundamental forecasts, as well as the forecast Dominion used in its 2016 IRP, seem reasonable, and both are reasonably consistent with the most recent long term fundamental forecast of natural gas prices that was published in March 2017 by EIA. Witness Johnson testified that it would be reasonable for the Commission to rely on the 2017 EIA forecast—a publicly available fundamental forecast—as a benchmark for judging the reasonableness of the fuel forecasts that DEC, DEP and Dominion use to calculate avoided energy costs. Additionally, Johnson testified that it would be reasonable for the Commission to require Dominion to use either the 2017 EIA forecast or the fundamental forecast it used in preparing its 2016 IRP. Witness Johnson also recommended that the Commission again reject the use of forward market data for anything more than the near-term future and direct DEC and DEP to reconstruct their fuel forecasts using a blend of forward market data and fundamentals data.

Discussion and Conclusions

The issue of establishing a long-term avoided energy rate poses difficulties because it of necessity relies upon projections of natural gas prices anticipated to occur for as far as 10 years into the future. As past experience has shown, predictions of future energy prices seldom accurately coincide with what those prices turn out to be. The primary dispute among the parties involves the method of projecting natural gas prices beyond the first five years of the relevant planning period. Duke and the Public Staff agree that it is appropriate to rely upon forward market gas pricing data for the first five year projections. Duke's witnesses' testimony supports reliance on such forward market price data for the years six forward also because, in Duke's experience and observation, the market is sufficiently fluid and robust to provide the most reliable predictions. The Public Staff, on the other hand, supports continued reliance on fundamental forecasts, arguing that after year five the current market is not so robust as to supplant the predictions of market analysts.

The Commission finds merit in some of the arguments each party raises but determines for purposes of this case not to agree completely with any but, in the Commission's expert judgment, to adopt a method relying on market data for eight years and fundamental forecasts thereafter.

The Commission agrees with Duke that lagging fundamental forecast pricing has proven to be inaccurate over the past few years and has led to overpayment to QFs. The Commission is concerned that undue reliance on higher fundamental forecast prices when a demonstrated liquid market exists can lead to arbitrage. Based on structural changes in the natural gas market, the Commission is also concerned that fundamental forecasts take significant time to develop and are only released by research firms once or twice per year.

On the other hand, the Commission shares the concerns expressed by the Public Staff that 10-year futures are less liquid based on existing transactions in the market so as to authorize exclusive reliance on them as advocated by Duke. While the parties differ on their assessment of the liquidity of the market with respect to 10-year futures, the Commission is satisfied that at the present time the number of such transactions is sufficiently fewer to prevent the Commission from relying completely on this method for establishing energy prices in this case at this time and will continue to monitor the liquidity in the market in future avoided cost proceedings.

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

The evidence supporting these findings of fact is found in the testimony of Duke witnesses Bowman and Holeman, Public Staff witness Metz, and NCSEA witness Johnson.

<u>Summary of the Testimony</u>

Duke witnesses Bowman and Holeman testified in support of Duke's proposal to amend the standard offer terms and conditions applicable to purchases of electricity from QF generators under Schedule PP and Schedule PP-H in order to more clearly define the circumstances that constitute an "emergency condition" during which DEC and DEP may curtail energy injections from QFs into the utility's electric system. Duke asserts that under FERC's regulations, absent contractual agreement otherwise, a QF selling power pursuant to a long-term contract may be curtailed and purchases discontinued only during "system emergency" conditions. Duke's proposed amended terms and conditions would expressly include any circumstance that requires imminent action by Duke to comply with North American Electric Reliability Corporation (NERC)/SERC Reliability Corporation (SERC) regulations or standards as an emergency condition.

Duke Witness Holeman testified at length regarding DEC's and DEP's independent BA responsibilities to manage system operations and maintain compliance with mandatory NERC/SERC reliability regulations within their separate BAAs. Witness Holeman recounted the history of NERC's current regime of over 100 mandatory and enforceable reliability standards, which evolved out of EPAct's response to the catastrophic 2003 northeast blackout. Witness Holeman testified that he is directly responsible for ensuring Duke's ongoing compliance with the NERC reliability standards.

Specific to DEP's growing experience managing the increasing levels of unscheduled or uncontrolled and non-dispatchable solar QF energy being injected into the BA, witness Holeman testified how DEP and DEC will be increasingly challenged to maintain compliance with the mandatory NERC BAL-001, BAL-002, and BAL-003 reliability standards. He testified that the "BAL" standards are designed to enhance the reliability of each interconnection by maintaining frequency within predefined limits every 30 minutes under all conditions, and effectively mandate every BA to balance generation resources to load demand within the BA during each 30-minute reporting period. Witness Holeman further testified that the BAL-001-2 standard was updated effective July 1, 2016, and now requires BAs to provide reserves for restoring resource-to-demand balance within 15 minutes following a sudden loss of a designated load following generating unit or disturbance event on the BA. In addition, he testified that a BA's failure to comply with the BAL reliability standards could result in system emergencies and reliability failures such as unscheduled power flows, unnecessary and automatic firm load shedding, or in a worst-case scenario, cascading outages across the interconnection.

Witness Holeman also testified that DEP's system operators currently have no dispatch control and no day-ahead planning control over the variable energy injections into the BA from solar QF generators. He further testified that by 2018, the DEP system is projected to have 2,200 MW of solar generation injecting unscheduled and unconstrained energy into the BA, and DEP system operators will increasingly be required to manage reliability in a reactive operational mode, with very limited forecast situational awareness of these variable and intermittent solar energy injections into the BA. Witness Holeman presented examples of how the growing levels of unscheduled solar QF energy being injected into the DEP BA is requiring system operators to manage both operationally excess and deficit in energy situations to maintain proper frequency in order to avoid potential BAL Standard violations. He testified that if the BA experiences too much unscheduled solar QF energy relative to real time load, the system operator must ramp down load following generating resources to the LROL of its Security Constrained Unit Commitment, which, if exceeded, can then require DEP to mitigate operationally excess energy in order to maintain proper frequency. He further testified that growing solar QF energy injections can also increase the risk of a deficit in energy relative to real-time demand in the BA, causing frequency to drop below the scheduled frequency. He also testified that, for example, if a change in weather or other event suddenly caused large volumes of solar QF energy to drop off the system, or in the late afternoon period as the solar energy drops off, and DEP was unable to ramp up its load-following generating resources fast enough, or if DEP were to lose a sizable network generating resource, then there would be a deficit of energy on the DEP system. Under these conditions, witness Holeman testified, DEP's system would be operating with compromised reliability and be at risk of violating the BAL-001 standard if the BA operated in these conditions for greater than 30 minutes. Witness Holeman further testified that these excess and deficit energy reliability impairments are directly correlated with significant amounts of unscheduled solar generation being injected into the BA, without the BA operator having operational control over the facilities. He argued that the ability to curtail solar QFs, as provided in Duke's proposed amended terms and conditions, will provide some measure of improved operational control during a potentially imminent system emergency situation.

Witness Holeman also responded to testimony of other witnesses by further testifying about the impacts to system reliability and risks of non-compliance with NERC's reliability standards, including the more rigorous operating contingency requirements to be imposed on BAs in the upcoming BAL-002 standard, effective January 1, 2018. Witness Holeman also highlighted the very steep up- and down-ramping requirements that DEP's load following generating units will face as 2,200 MW of solar QF penetrations come online in 2018, as well as the high likelihood of operational curtailments of QFs that will be required in real time to ensure compliance with NERC's reliability standards and to avoid risks to reliable electric service, as additional QFs continue to come online. Witness Holeman also testified the risks and limits of the hourly, as-available non-firm, curtailable transmission paths underlying the Joint Dispatch Agreement between DEC and DEP, which he emphasized is not a tool for DEP and DEP system operators to use to manage balancing, regulating, or operating reserve requirements. Witness Holeman addressed NCSEA witness Johnson's testimony that it was feasible for the DEP BA to rely on the DEC BA's pumped storage assets to manage DEP's system reliability long-term operational commitments and NERC reliability obligations, stating that it is not a long-term sustainable solution as DEC and DEP are independent BAs with separate obligations to comply with NERC's reliability standards. Witness Holeman also testified that DEC and DEP are currently in the process of developing an operating procedure document for the management of system emergency curtailments of QFs and other non-QF generators on a similarly situated, non-discriminatory basis, and committed to share the document with the Public Staff as soon as it is completed and to file such procedures with the Commission after discussions with the Public Staff.

In concluding his testimony, witness Holeman testified to his 31 years of experience as a system operator and emphasized the significant challenge facing DEP and DEC system operators in the planning horizon under the current operational tool set to ensure system reliability and security as the 2,200 MW of QF solar projected to be online in early 2018 will be the largest aggregate generating resource in the Carolinas. Witness Holeman also highlighted the need for fair, non-discriminatory operating procedures that will provide DEP more centralized operational control to better manage the intermittency and uncertainty increasingly caused by the growing levels of utility scale solar.

Witness Bowman also addressed witness Johnson's recommendation that the Commission mandate DEC and DEP to enter into take or pay arrangements with QFs that result in customers paying for QF solar power that is simply "discarded" or not used to meet system load. She testified that witness Johnson provides no evidence that any other public service commission has ever approved a take or pay contract in its implementation of PURPA, and that mandating such a proposal in North Carolina based upon current economic and regulatory circumstances would be completely unjust and unreasonable. Witness Bowman also cited Order No. 69, arguing that nothing in PURPA requires customers to pay QFs for unused or unneeded energy or capacity.

Public Staff witness Metz testified that he agreed with witness Holeman that must-take energy from PURPA QFs is causing potential concerns within the DEP BA. He also agreed with witness Holeman that the utilities' limited ability to control PURPA QF solar generation creates challenges for BAs trying to match generation with load while staying within the limits required by NERC. Witness Metz stated that DEC and DEP already have language in their negotiated contracts that allows for a limited amount of curtailment each year through the use of a "Dispatch Down" instruction, but curtailment due to system emergencies does not count toward the limit. According to witness Metz, the Public Staff believes that the Federal Code already allows the utilities to curtail QFs when faced with an imminent violation of a NERC BAL Standard because an imminent violation of a NERC BAL Standard constitutes a system emergency as defined by 18 C.F.R. 292.101(b)(4). Witness Metz further testified that the Public Staff is in discussions with Duke about filing its processes and procedures for curtailing QFs in a non-discriminatory fashion.

NCSEA witness Johnson testified that the issues described by witness Holeman were legitimate, but viewed them as "growing pains." He testified that he was troubled by Duke's solution of "declaring a system emergency when solar energy is displacing some of Duke's less flexible generating resources." Witness Johnson testified that the proposal forces the QFs to shoulder too much risk because there is no limitation on how often an emergency can be declared or how much revenue a QF will lose. Witness Johnson stated that two other options to help with the excess energy problem are for Duke to modify how it utilizes its pumped storage generation and to negotiate "Take or Pay" contracts with some of the solar QFs.

Discussion and Conclusions

A "system emergency" is "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." 18 C.F.R. 292.101(b)(4). During any system emergency, a utility may discontinue purchases from a qualifying facility if such purchases would contribute to such emergency. 18 C.F.R. 292.307(b)(1). The disputed issue here is whether an imminent violation of NERC standards is within the definition of system emergency, and whether it is appropriate to allow a utility to discontinue purchases or curtail output from a QF during a system emergency. If the Commission concludes that it is, Duke argues that it would be appropriate to amend the terms and conditions included in its standard offer contract documents.

The Commission finds persuasive witness Holeman's testimony regarding the new and unique technical and operational circumstances facing utilities. As he testified, this task has grown more complicated because of the presence of solar-powered QFs interconnected to the Duke electric systems, and particularly DEP's system in eastern North Carolina. In addition, he testified Duke's responsibilities as BAAs to comply with increasingly complicated and rigorous reliability standards issued by NERC and SERC. His testimony is largely consistent with, and supported by, the testimony of Public Staff witness Metz.

The Commission rejects witness Johnson's argument that the operational challenges facing the Utilities in managing their electric systems are mere growing pains. For reasons discussed below, the Commission also rejects his proposal to require use of the DEC's pumped storage generation to mitigate operational challenges experienced in the DEP East BA, and the notion of including a take-or-pay provision in the standard contract offer. The Commission agrees with witness Bowman that a take-or-pay provision would introduce uncertainty about compliance with the limits of PURPA's requirements, expressed in Order No. 69, that utilities are not required to pay for energy and capacity in excess of their system needs. See Order No. 69, at 12,219. While the Commission recognizes that allowing curtailment or discontinuance of QFs purchases shifts some risk to QFs, the compliance filing required by this order and the availability of arbitration before the Commission serve as a sufficient protection against this risk. Moreover, the Commission expects the Utilities to observe the standards of good faith in all their dealings with QFs, including the exercise of curtailment or discontinuance of QF purchases.

As witnesses Bowman and Holeman testified, DEP and DEC continue to operate as separate BAAs and utilities, and each is responsible for its own independent resource planning and operations, as directed under the Commission's Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, issued on June 29, 2012, in Docket Nos. E-2, Sub 998 and E-7, Sub 986.[1] As witnesses Holeman and Metz testified, the JDA is an opportunistic, economic, incremental-cost energy transfer tool, which relies on hour-by-hour, as-available, non-firm, curtailable transmission and does not reduce availability of firm transmission for long-term wholesale transactions of other network transmission customers. They further testified that relying on the JDA to manage operationally excess energy poses significant system operational risks of transmission curtailment and that the JDA was not designed as a long-term solution to manage operationally excess energy supplied by solar-powered QFs. The Commission is not inclined to compound the complexities of operating the electric system by requiring use of the JDA in this manner. Therefore, the Commission agrees with the Duke and Public Staff witnesses on this issue, and finds that it is inappropriate to approve witness Johnson's proposal.

Based on the foregoing and the entire record herein, the Commission determines that system emergency includes a condition where the Utilities' system operators are operating their load-following generating fleets at LROL and are confronted with circumstances that require immediate action to comply with mandatory NERC/SERC reliability standards, including, but not limited to, the BAL standards. Thus, the Commission concludes that an imminent violation of NERC/SERC standards is a system emergency. The Commission is persuaded that the NERC/SERC reliability standards were established to avoid conditions on a utility's system which are likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property, and that the number and volume of solar-powered QFs on Duke's electric systems makes these conditions more likely to occur with more frequency. Thus, the Commission further determines that in a system emergency, it is appropriate to allow the Utilities to curtail QF generated power or, in extreme conditions, to discontinue purchases from QFs, if the purchase of that power would contribute to the emergency condition.[2] The Public Staff argues that there is no need to amend the standard offer contract terms and conditions because the Utilities curtailment authority is based in FERC's regulations, but the Commission cannot identify any evidence that allowing the amendment to the terms and conditions will cause any

[1] See, e.g., DEC/DEP Regulatory Condition No. 4.1, which provides that "DEC and DEP acknowledge that the Commission's approval of the merger and the transfer of dispatch control from DEP to DEC for purposes of implementing the JDA and any successor document is conditioned upon the JDA never being interpreted as providing for:

(a) A single integrated electric system

(b) A single BAA, control area, or transmission system

(c) Joint planning or joint development of generation or transmission

(d) DEC or DEP to construct generation or transmission facilities for the benefit of the other

(e) The transfer of any rights to generation or transmission facilities from DEC to DEP to the other, or

(f) Any equalization of DEC's and DEP' production costs or rates."

[2] While this finding is specific to the standard offer terms and conditions, the Commission also determines that Duke's inclusion of dispatch down and similar contractual provisions in the non-standard offer PPAs with larger QFs is consistent with this determination. The Commission encourages the Utilities to continue to evaluate requiring enhanced contractual rights that will more effectively provide utility system operators scheduling and operational control rights over deliveries of energy by QFs to assure continued reliable electric service in North Carolina. This evaluation and the exercise of these rights in the negotiated contract setting should be consistent with the Commission's findings and conclusions in this order.

discriminatory harm to QFs. Therefore, the Commission concludes that Duke's proposed amendment to the terms and conditions should be approved.

Duke and the Public Staff's witnesses also testified that the development of operating procedures to manage system emergency curtailments of QFs and other non-QF generators on a similarly situated, non-discriminatory basis is underway. Duke committed to share this document with the Public Staff and file it with the Commission. The Commission determines that establishing non-discriminatory and transparent system emergency curtailment operating procedures is appropriate and justified by the requirements of PURPA. The Commission further determines that it is appropriate to require Duke to file its planned system emergency curtailment operating procedures as part of the compliance filings required by this order. In addition, the Commission determines that it is appropriate, as proposed by the Public Staff, to require the Utilities to file quarterly reports with the Commission documenting each instance where a utility is faced with, or declares an imminent violation of a NERC Standard or any other type of system emergency, that causes or potentially causes the utility to curtail QFs. These reports shall include the following information: (1) whether the utility curtailed any QF(s); (2) the procedures leading up to the decision to curtail the QF(s); (3) how the utility determined which QF(s) to curtail; (4) the duration of the curtailment; (5) the duration of the system emergency; and (6) any other documentation required to be sent to any other state or federal agencies due to occurrence of a system emergency.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 16

The evidence supporting these findings of fact is found in the testimony of Dominion witnesses Gaskill and Petrie, Public Staff witness Hinton, and NCSEA witness Johnson.

Summary of the Testimony

Dominion witnesses Gaskill and Petrie testified in support of Dominion's proposal to adjust its avoided energy rates to reflect the locational energy value its North Carolina service area as opposed to the entire DOM Zone. Dominion witness Petrie testified that, as in past avoided cost proceedings, energy prices under Dominion's proposed Schedule 19-LMP are based on the hourly PJM Interconnection, L.L.C. (PJM) Dominion Zone (DOM Zone) Day Ahead Locational Marginal Price (LMP) expressed as $/MWh. Witnesses Gaskill and Petrie testified that LMPs reflect the value of energy at specific locations, or nodes, on the grid. As a result, areas that need additional generation to meet load will realize higher LMPs, which provide incentive for generation to locate in that place, while conversely, areas where generation is not valuable due to lack of congestion or losses will realize lower LMPs. Further, witness Petrie testified that the average of the Day Ahead LMP values in the billing month, divided by 10 to derive a cents per kWh price, is applied to the QF's total net generation during the billing month. Witness Petrie further testified that the LMPs in North Carolina were over 4% lower than those for the DOM Zone, and were likely to be even lower as compared to the DOM Zone in the future due to the future solar development in its North Carolina service territory.

Witness Petrie testified that power price inputs to and outputs from the PROMOD model Dominion Energy North Carolina uses to calculate avoided energy costs are expressed at the DOM Zone level, not at the nodal (local) level. He noted that the DOM Zone is an aggregate pricing point in the PJM energy market, and represents the average of LMPs of all nodes within the DOM Zone. Witness Petrie offered data, calculated using the average day-ahead LMPs at six North Carolina nodes selected due to their geographic diversity and proximity to QF development, showing that on-peak energy prices for Option B were 4.4% lower in Dominion Energy North Carolina's North Carolina service area than in the DOM Zone during the 2014-2016 time period, and 4.8% lower during off-peak periods. Energy prices for Option A were 4.7% lower during both on- and off-peak periods during this time. He testified that this LMP disparity is typical for grid locations with an oversupply of generation relative to customer demand. He stated that, all things being equal, Dominion's North Carolina LMPs are likely to be even lower in the future as additional distributed solar comes onto its system, leading to additional losses and congestion issues.

Witness Petrie testified that to account for this difference, Dominion adjusted the PROMOD model results to reflect the locational value of energy for QF deliveries in the North Carolina service area to ensure that the avoided energy rates Dominion and its customers pay are as accurate as possible. The adjustment reduced Option B on-peak rates by 4.4% and off-peak rates by 4.8%, and reduced Option A on- and off-peak rates by 4.7%, consistent with the historical data.

Witness Gaskill testified that, while Dominion's fuel rates are based on the total system cost of energy, its system cost of energy is fundamentally derived from the LMPs where the load and generation are located. He further testified that Dominion's total system energy cost is equal to the net of (1) the cost to supply load, and (2) generation energy revenues and costs. He demonstrated through several examples that, if additional generation is added (or load is reduced) in a location with low LMPs, it has less effect on lowering net system costs than generation that is added to a location with high LMPs. He testified that the avoided cost of added generation or load reduction is equal to the LMP at the bus where the generation or load reduction occurs.

Witness Gaskill also testified that lower LMPs indicate that additional generation in this area is less valuable than generation in other areas of the DOM Zone, and that the discounted value of generation in this area must therefore be incorporated into the forecasted avoided energy price, because that is the actual value PJM gives to this generation. He stated that Dominion Energy North Carolina's proposal to adjust avoided energy rates to reflect the locational energy value of its North Carolina service area would result in rates that better reflect its actual avoided cost for QFs in this area. He testified that, if Dominion Energy North Carolina does not make this adjustment, customers will pay rates that exceed the marginal energy costs that QFs in its North Carolina service area actually avoid. Finally, witness Gaskill testified that Dominion's proposed LMP adjustment is consistent with the peaker method, because the underlying theory behind the peaker method is that the long-run avoided energy cost is equal to the marginal costs of the utility's system in each hour and, as shown by his example, the LMP where the generation is located directly translates into the marginal cost avoided for the utility system.

No party contested Dominion's proposal to continue to offer Schedule 19-LMP as an alternative to Schedule 19-FP or raised any issue with the proposed Schedule 19-LMP.

Public Staff witness Hinton stated that this proposal was reasonable based on Dominion's showing that the LMPs in North Carolina had consistently been lower than those in the DOM Zone.

NCSEA argues that, conceptually, using LMP data to help refine rates is reasonable, as LMPs may be relevant to the problem of how best to encourage QF power to be generated where it is most valuable. NCSEA witness Johnson indicated that he did not oppose the proposal on a conceptual level as it sent appropriate price signals. However, he argued that there were a number of issues that should be investigated before adoption by the Commission, including the amount of and the reasons for the difference between the LMPs. Further, he testified that additional granularity and further refinement to Dominion's approach may be warranted before the Commission authorizes Dominion to implement this proposal, in the interest of transparency and ensuring that the method for accounting for locational value results in encouraging QFs to locate where the QF can provide value to the utility and its ratepayers. Witness Johnson further testifies that, with additional study and data analysis, detailed location-specific information could be developed that considers: 1) proximity to load centers and other factors which influence line losses; 2) opportunities to reduce congestion on distribution lines, substations, and transmission lines which could postpone or avoid upgrades to these facilities within the relevant planning horizon; and 3) opportunities to improve local reliability.

Dominion witness Gaskill testified in response to witness Johnson that Dominion had already provided in testimony and discovery information that should address most of the concerns raised by Dr. Johnson. Witness Gaskill noted that Dominion would also be able to develop more granular prices for negotiated contract avoided energy rates based on the specific location of the QF.

Discussion and Conclusions

The Commission finds persuasive the testimony of Dominion witnesses Petrie and Gaskill that LMPs reflect the underlying supply and demand, and associated local congestion and marginal losses, across the electric system. The Commission agrees that as supply increases, LMPs decrease, and as demand increases, LMPs increase; and thus, the avoided cost of added generation or load reduction is equal to the LMP at the location where the generation or load reduction occurs. The Commission is also persuaded by witness Gaskill's testimony that the utility's marginal system cost of energy, which is the measure of avoided energy cost under the peaker method, is fundamentally derived from the LMPs associated with the location of load and generation. The Commission recognizes, as testified to by witnesses Petrie and Gaskill, that as more generation is added to Dominion's North Carolina service area, a location that is saturated with narrowly concentrated distributed generation, the congestion and marginal losses costs increase, reflecting the re-dispatch cost to enable this generation to "flow" to locations where it is needed to serve load. This result is demonstrated by witness Gaskill's rebuttal exhibit, which shows on-peak congestion between Dominion's North Carolina nodes and the DOM Zone during 2016 of $1.84/MWh, which he estimates would result in $2 million annually in congestion costs for North Carolina QFs under contract. Such significant added cost supports using the LMPs associated with the locations where QFs are generating to correctly calculate avoided cost rates. In addition, the Commission is persuaded by Dominion's testimony that as more generation is added to this area relative to load, the disparity between North Carolina LMPs and DOM Zone LMP is likely to increase.

Dominion's proposed use of North Carolina LMPs is supported by Public Staff witness Hinton's testimony citing data showing that the LMPs for North Carolina nodes have been consistently lower than the DOM Zone average LMPs. Further, NCSEA witness Johnson agreed with the principle of reflecting local LMPs in avoided cost pricing. The Commission determines that witness Gaskill sufficiently addressed witness Johnson's proposed questions for the purposes of this proceeding. However, the Commission determines it is appropriate to monitor the impact of this adjustment and to require Dominion to address this issue in the next biennial avoided cost proceeding. Finally, the Commission determines that witness Johnson's recommendation to use LMP data to refine the QF rates is helpful, and agrees that additional granularity and further refinement of this approach is appropriate. Therefore, the Commission will direct Dominion to address the questions raised by witness Johnson in its initial filings in the next biennial avoided cost proceeding. The Commission does not agree with witness Johnson that these questions should be answered before approving Dominion's proposed change.

Based upon the foregoing and the entire record herein, the Commission determines that Dominion's proposal to adjust its avoided energy cost rates to account for the lower locational value of generation in its North Carolina service area, as compared to DOM Zone LMPs overall, is appropriate. The Commission concludes that Dominion's proposed adjustment will allow those rates to better reflect its actual avoided system energy cost, as required by PURPA and FERC's implementing regulations. Therefore, Dominion's proposed LMP adjustment to avoided energy cost rates should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17 AND 18

The evidence supporting these findings of fact is found in the testimonies of Dominion Energy witnesses Gaskill, Public Staff witnesses Metz and Hinton, NCSEA witness Johnson, and SACE witness Vitolo.

Summary of the Testimony

Dominion witness Gaskill testified in support of Dominion's proposal to eliminate the 3% adder associated with line loss avoidance from the avoided energy rate methodology for the standard offer contract. He testified that, when deployed effectively, distributed solar generation can avoid line losses, because when load on a particular circuit exceeds the generation interconnected to that circuit, solar or other generation at that location can often directly serve the load on that circuit and avoid transmission and transformer losses that would otherwise be associated with serving that load. He further testified that the 3% adder was established under the assumption that QF distributed generation would be less than load on interconnected circuits, thereby permitting line losses arising from centrally-located generation to be reduced or eliminated.

Witness Gaskill testified that this assumption is no longer true because losses are generally only avoided when the substation load exceeds the local distributed generation on a substation bus. Otherwise, he stated, excess generation flows in reverse, or "backflows," onto the transmission grid to travel to serve load on a different circuit. In those cases, he testified, an increase in system line losses can actually occur, since the distributed generation must pass through two transformers (distribution to transmission to distribution) to reach the load that needs it. He further testified that the volume of distributed solar generation on the North Carolina portion of Dominion's system has reached the point that it either is or will soon exceed the load requirement on most circuits, and that, when that happens, backflow occurs. In addition, he testified that, when backflow occurs, many of the benefits and avoided costs attributed to distributed generation—scalability, mobility, and resulting reduced congestion and improved reliability—are lost. In particular, no line losses are avoided.

Witness Gaskill made reference to an exhibit that included data showing that backflow already occurs most of the time on some of Dominion's North Carolina substations and part of the time on other substations. Specifically, he offered data showing hourly load flow from September 2015 through September 2016 on Dominion's 33 distribution transformers that have interconnected distributed solar facilities. That data shows that 11 of those transformers are experiencing a predominantly constant backflow, indicating that the energy delivered from the distributed generation connected at these substations exceeds the load at those locations. Of the remaining 22 transformers, 18 are "neutral," meaning they either have a mix of forward and reverse flows or that there is only a small amount of excess load remaining, such that the interconnection of additional distributed solar at these transformers will tip the scales, resulting in power backflow, and not result in additional line loss savings at these locations. Only four transformers still showed a clear margin of load over currently interconnected distributed solar generation and, thus, the ability to host additional distributed solar without resulting in backflow. Witness Gaskill noted, however, that the addition of just one or two more 5-MW projects at these locations will eliminate this margin. He also noted that the data did not include distributed solar generation that commenced operations since September 2016, or the remaining approximate 600 MW of distributed solar generation in Dominion's interconnection queue that has not yet commenced operations. He testified that, when this generation is connected, the backflow on Dominion's substations will increase substantially.

In light of the foregoing, witness Gaskill recommended that the 3% line loss adder should be eliminated for future QFs eligible for the standard offer. Without this change, he stated, customers will pay for losses that are not actually avoided. He noted that the data presented shows that customers are in many cases already paying for a loss adder under 2012 and 2014 biennial period contracts where no actual losses are being avoided. He argued that, while QFs already receiving the line loss adder may continue to receive it as specified in their contracts, future QFs should not be paid for losses that are not actually avoided. Witness Gaskill clarified that, for QFs not eligible for the standard offer, Dominion may calculate project-specific loss percentages, either positive or negative, depending on each project's specific interconnection location.

SACE witness Vitolo disagreed with Dominion's line loss analysis. Witness Vitolo agreed that increasing backflow from a substation that is already backflowing will not necessarily result in line loss avoidance at that specific time, but contended that, to the extent that a substation receives positive flow from the transmission system at any half-hour, an operating local distribution generator will avoid transmission line losses at that time. He asserted that as long as there are hours in a year when the transmission grid sees a net reduction of total demand, there will be line loss avoidance. Witness Vitolo contended that based on his own analysis of power flows at the 33 Dominion transformers, only one of those transformers showed a majority of half-hours with backflow. He opined that each of the other 10 substations labeled "negative" in Dominion's analysis experienced positive flow during most of their hours, and claimed that line losses would be avoided with additional solar generation added to all but one of the substations. Witness Vitolo claimed based on his analysis that eliminating the line loss adder would be inappropriate. He recommended that the Commission direct Dominion to calculate line loss avoidance with enough granularity to compensate renewable QFs for the value they provide in avoiding line loss and that, if such calculations are not feasible, it should continue to apply the 3% line loss adder. (T. Vol. 7 at 57-60)

NCSEA witness Johnson agreed that due to the backflow issue at the substations in certain areas that line losses are not avoided as much as in the past, but that the utilities do not take into account other benefits, including line losses that can be avoided by not sending the electricity over the transmission system, and costs savings from not having to upgrade the transmission system itself. Witness Johnson stated that in the Sub 140 proceeding, the Commission decided it should not include other cost and benefits of distributed solar in the avoided cost calculation until future studies and calculation methods have further developed.

Public Staff witness Metz provided the history of the line loss adder, stating that it first appeared in the avoided cost rate schedules of North Carolina Power (now Dominion), filed in Docket No. E-100, Sub 53, in 1987. The rate was last increased from 2.7% to 3% in the 2008 avoided cost proceeding. Witness Metz testified that the Pubic Staff agrees with Dominion's proposal to eliminate the line loss adder from the standard offer contract based on the number of substations already experiencing power backflows and the number projected to experience power backflows in the future. Witness Metz then stated that the Public Staff does not believe DEC or DEP should eliminate the line loss adder from their standard offer contract at this point, but should continue to evaluate the issue and include their findings in a study, or equivalent, during the next avoided cost proceeding.

Dominion witness Gaskill responded to the testimony of the other witnesses, emphasizing witness Metz's recognition of the forward-looking nature of this proceeding. He testified that, while many Dominion substations already realize significant reverse flow, any avoided line loss that remains at this point will continue to diminish in the future as additional distributed generation is interconnected. He also emphasized that it is inappropriate to continue to pay for avoided line losses when the evidence is clear that the typical QF that signs a standard contract pursuant to this proceeding will likely not avoid any line losses. Witness Gaskill further testified that witness Vitolo's claim that only one of the 33 transformers experienced backflow during a majority of the time was incorrect. He testified that witness Vitolo's analysis included hours, including nighttime hours, when no solar QF generation would be producing. He also noted that witness Vitolo did not account for the fact that QF generation was incrementally added over the course of the year, which explains why the data would show more hours with backflow late in the year than early in the year, and did not recognize that the focus should be the state of the flow as it exists today and will exist in the future. He presented an example of one transformer at which reverse flow clearly increased at the point in time at which new generation was added, such that by the end of the time period studied, that transformer was experiencing reverse flow during nearly all daylight hours. Witness Gaskill also noted that, since the line flows presented in his direct exhibit only accounted for distributed generation that was operational at that time—293 MW as of September 2016—considering that the capacity of projects with PPAs or LEOs that have not yet come online exceeds 600 MW, the flows presented in the exhibit included only approximately half of the QF generation that has committed to sell to Dominion. He stated that many of the transformers identified as "neutral" or "positive" in his exhibit will soon experience predominately reverse flow as these additional QFs commence operations. Finally, witness Gaskill testified that because in this proceeding Dominion is proposing rates and terms for the standard offer, it must derive a rate that applies to the average QF all across its North Carolina service area. As the amount of QF generation committed to Dominion already exceeds average on-peak load, the average QF going forward will not avoid additional line losses and will, in some cases, add to such losses. Since the avoided cost rates set in this case are forward-looking, the data clearly shows that most QFs subject to these rates will not avoid additional line losses.

In response to witness Johnson's testimony, witness Gaskill noted that Dominion has incorporated in its avoided cost rates those avoided costs that are reasonably known and quantifiable, including for avoided energy, capacity, line losses, and congestion. He testified that it is only now, in the absence of those benefits as QF generation has exceeded load and those benefits are reduced or eliminated, that Dominion has proposed to reduce or eliminate the associated costs from its standard avoided cost rates. He noted that Dominion shares Public Staff witness Hinton's concern regarding the uncertainty of integration costs, but because its integration costs studies have not yet quantified those costs, it has not proposed to include any integration costs into its avoided cost rates at this time. Witness Gaskill further testified that, with respect to QFs not eligible for the standard offer, Dominion can evaluate the line loss characteristics of a specific circuit to which a QF plans to interconnect, and model that location with and without the additional generation to estimate the difference in line loss and determine whether avoided line loss should be reflected in the rate. In addition, witness Gaskill testified that line losses are avoided when a distribution level QF allows the utility to avoid transmitting generation across the transmission line, through the transformer to the load. He testified that if the QF does not serve load on that circuit, it nevertheless reverse flows, and line losses are not avoided and may in fact increase. He further testified that on Dominion's North Carolina system, the majority of circuits where QFs are interconnecting either are or will soon experience reverse flow, such that any line loss avoidance for new QFs will be zero or even negative, meaning the QF is actually contributing to, rather than avoiding, line losses. He opined that it would require a large amount of load growth in a short period of time for QFs that will interconnect in Dominion's service area under this proceeding to avoid line losses, and that he did not foresee that occurring. He confirmed that part of a discovery response, which he did not prepare, stated that Dominion has not quantified system losses associated with QFs in its North Carolina territory during times when backflow was and was not occurring over the past two years. He clarified that, as the purpose of the standard offer is to apply to all small QFs, Dominion has decided to consider the average across its North Carolina system to be zero, even though it is likely that the growing QF solar generation may actually be adding to line losses. He testified that this cannot be a QF-specific determination, since it is for the standard offer projects.

Witness Gaskill's testimony also included examples of transformer data from his line loss exhibit. He examined one transformer that he had labeled as "positive," meaning that generally load was being offset by generation at that location, and noted that the location had 10-15 MW of load, with another 13 MW of new generation in the queue to come online. He testified that once that new generation interconnects, the flow will shift to "neutral" at that location, because the interconnected generation will, when producing, offset the load at that location. He testified further that any additional generation interconnected at that location would not avoid any line losses, because all potential avoided line loss is being covered by the existing, soon-to-be interconnected generation at that transformer. In another example, witness Gaskill testified how the Whitakers substation data shows positive load flow during nighttime hours when a solar facility does not generate, but reverse flow when the facility generates during daytime hours. He noted that where a location already sees reverse flow from negative load flow, adding more generation to that location will only increase the reverse flow. He testified that Dominion knows how much generation is in line to be constructed and begin operations, and that once that generation comes online, the vast majority of its substations will indicate predominantly reverse flow when that generation is producing. He testified that, for that reason, Dominion has concluded that across its North Carolina service territory, any additional generation at these locations will not on average avoid line loss, and most locations will incur additional line losses due to increased reverse flow. He noted that, despite its expectation that additional line losses will be incurred, Dominion settled on zero avoided line loss for purposes of its standard avoided cost rates.

Witness Vitolo agreed that the purpose of the line loss adder has been to compensate QFs for line losses that their facilities allow utilities to avoid. He also agreed that, according to FERC, paying for line loss is appropriate where the utility avoids line loss costs it would have incurred but for the QF being at that location. He agreed further that solar QFs can avoid line loss by meeting at least in part the requirements of the load at a particular location, so that the electricity does not need to travel elsewhere on the system. He recognized that backflow can occur and that, depending on the details of the substation and the flow on the transmission grid, increasing backflow from a substation already backflowing will not necessarily result in line loss avoidance at that time. He admitted that in his own line loss analysis, while he removed data points for which the power flow registered as zero, and started his analysis at each substation at the point in time at which backflow started to occur, he did not remove any data points corresponding to non-daylight hours. He agreed that the vast majority of QFs coming online on Dominion's North Carolina system are solar QFs, and that a substantial number of the next 100 QFs to come online will be solar. On cross and redirect, witness Vitolo testified that each of Dominion's substations would present a different picture than the others. However, with respect to an example transformer about which Dominion counsel questioned him, he also agreed that there is a solar correlation associated with the times of day that the example transformer showed a negative power flow (i.e., the negative flow occurred during daylight hours), and he agreed that no negative power flows occurred after 6:00 pm on that day for that transformer.

Discussion and Conclusions

The Commission finds persuasive the testimony of Dominion witness Gaskill and Public Staff witness Metz regarding the impact that distributed generation, and specifically solar-powered QFs, is having on the operation of Dominion's electric system in North Carolina. The Commission agrees with witnesses Gaskill and Metz that line losses are avoided when distributed generation can offset the load at a particular location, thereby reducing the flow of power required to travel from the transmission system to the distribution system to serve that load and avoiding the line losses that would be associated with that power flow. The Commission has historically required Dominion to include the line loss adder in the calculation of its avoided energy rates, because line losses are a known and quantifiable benefit of distributed generation. However, the Commission is persuaded that when the distributed generation connected at a particular location exceeds the load requirements at that location, upstream line losses are not actually avoided, because there is no local load being offset. In that case, the power must flow back onto the system, traveling through transformers and onto transmission lines, with the accompanying, and additional, line losses. Dominion's analysis, as presented by witness Gaskill, demonstrates that the majority of its transformers to which QF generation is connected in North Carolina are experiencing reverse power flows during the hours of the day when solar generation would be expected to produce power. Because this analysis did not account for the substantial volume of distributed solar capacity that is currently moving through the interconnection queue or under construction, the Commission agrees with witnesses Gaskill and Metz, that, once this additional generation is added to these locations, reverse flows will increase, and line losses will likely increase, and not be avoided.

The Commission carefully considered the testimony in opposition to Dominion's proposal, and finds that witness Gaskill's testimony has sufficiently responded to these arguments. For example, witness Gaskill demonstrated that witness Vitolo's criticisms of Dominion's load flow analysis is flawed in that it included nighttime hours, tending to skew the results in favor of a suggestion that these locations are almost all experiencing positive power flows. Witness Gaskill also demonstrated that, while witness Vitolo limited his analysis of each transformer to the period of time during which QF generation was located there (as opposed to looking at power flows that occurred prior to any QF generation being connected), he did not account for the subsequent increases in reverse flows that occurred at several transformers once additional facilities came online. Finally, as witness Gaskill testified, witness Vitolo did not account for the QFs expected to come online in the near-term. This demonstrates the connection between the addition of incremental QF generation and the increased degree of reverse power flow. Witness Gaskill's testimony also sufficiently refuted the arguments of NCSEA witness Johnson that the Utilities do not take into account other benefits, including line losses that can be avoided by not sending the electricity over the transmission system, and costs savings from not having to upgrade the transmission system itself. The Commission agrees with and accepts witness Gaskill's testimony that as the situation developed to the current state of QF generation exceeding Dominion's system load, these savings became reasonably known and quantifiable. The Commission concludes that this is consistent with the Commission's historical approach to calculating the Utilities' avoided costs and that Dominion has proceeded reasonably in this respect as well as in refraining from proposing to include any integration costs into its avoided cost rates until its studies are able to quantify such costs.

Based on the foregoing and the entire record herein, the Commission finds that backflows are occurring with regularity on a number of Dominion's distribution system circuits, and that based upon the number and aggregate size of QF projects that are seeking to interconnect to Dominion's electric system, backflows are likely to occur more frequently on more distribution circuits in the future. The Commission further determines that this development greatly reduces or eliminates the benefits of the solar QFs line loss avoidances, which historically have been accounted for in Dominion's avoided energy rate through the 3% line loss adder. Therefore, the Commission determines that it is appropriate for Dominion to eliminate the 3% line loss adder from its standard offer avoided cost payments to distribution-connected QFs eligible for the standard offer.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 19

The evidence supporting these findings of fact is found in the testimony of Duke witness Snider, Public Staff witness Metz, and NCSEA witness Johnson.

Summary of the Testimony

Public Staff witness Metz testified that Duke includes a line loss adjustment in DEC and DEP's avoided energy rates. He further testified that while Dominion makes the adjustment after calculating the avoided energy rates, DEC and DEP incorporates the calculation into their avoided energy rates. Witness Metz then testified that neither DEC nor DEP have proposed to eliminate the line loss factors from Duke's calculations, and the Public Staff does not recommend that they do so at this time. However, witness Metz testified that it may be appropriate for DEP to consider such an adjustment in future proceedings given the similar flow conditions to those experienced by Dominion. He further testified that it would be inappropriate to recommend that DEP make this adjustment without more thorough study of this issue. Therefore, he concluded that DEP should continue to evaluate the issue and include their findings in a study, or equivalent, during the next avoided cost proceeding. Finally, witness Metz testified that DEC has not experienced the same power flow conditions, and that it would be inappropriate for DEC to eliminate the adjustment for line losses at this time.

Witness Snider testified that he agreed with Public Staff witness Metz that DEP should consider eliminating the line loss adder in future avoided cost proceedings because of the abundance of distributed generation. He further testified that Duke may also evaluate this issue as part of specific avoided cost characteristics for larger distribution-connected QFs.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission determines that it is appropriate for DEC and DEP to continue to incorporate the line loss factor in their standard offer avoided energy calculations. The Commission further determines that it is appropriate to require Duke to study the impact of distribution generation on power flows on their distribution circuits and provide the results of that study as a part of their filings in the next biennial avoided cost proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 20

The evidence supporting this finding of fact is found in the testimony of Duke witness Snider, Dominion witnesses Gaskill and Petrie, Public Staff witness Hinton, and NCSEA witness Johnson.

Summary of the Testimony

Witness Snider testified that while he designed and supported generic avoided cost rates under the peaker method to apply to all QFs eligible for the standard offer, the recent high penetrations of QF solar resources as well as proposed solar QF projects under development had caused Duke to more specifically evaluate the impact of solar QFs on Duke's planning and reliability. He described Duke's 2016 resource adequacy studies and recent shift to winter planning, emphasizing that the load and resource balance has changed drastically in the past two-to-three years, driven in large part by the high penetration of solar. He also noted that Duke may need to consider the ancillary services impact of high levels of must-take solar when considering additional generation resources to satisfy winter reserve margin requirements, and to ensure adequate system ramping capability and operational flexibility. Witness Snider also noted that the generic avoided capacity rates filed in this proceeding tend to over-compensate solar QFs in excess of the capacity actually avoided due to the broad on-peak hour definitions under Options A and B of Schedule PP. Witness Snider testified that Duke intended to evaluate these solar-specific issues in the context of negotiated PPAs with larger QFs and in the next biennial proceeding.

Witness Snider further testified that, given the large increase in solar QFs in the Duke territories, evaluating solar specific avoided cost rates for larger QFs is appropriate. Witness Snider additionally believed that advancing a solar-specific rate in a standard offer filing in a subsequent avoided cost proceeding may be appropriate. With respect to the factors that the Commission should consider regarding a solar QF's specific characteristics and impact on energy value, witness Snider testified that generic QF rates under the peaker method apply to any PURPA QF eligible for the standard offer, and the energy value assumes an equal amount of generic QF generation is available in every hour. Witness Snider noted that generation must be available and dispatchable to meet the dynamic needs of the consumer, which change minute-to-minute. He further testified that a utility system can only accommodate a finite amount of intermittent generation that does not follow load, and that the net impact of a large amount of this type of generation on a given system results in the need for additional operating reserves and other operating adjustments. Witness Snider further testified that Duke was not including the cost of these additional operational adjustments in the calculation of the filed standard offer rates for small QFs in this proceeding. However, he emphasized that the costs for such additional operations are a growing concern and should be analyzed for larger QFs.

Witness Snider outlined how Duke would implement a solar-specific energy rate if directed to do so. He testified that to calculate the energy specific portion of the avoided cost rates for solar QFs, the Companies would perform two production cost runs, one with, and one without, 100 MW of free solar generation using a general diversified solar profile. He testified that the use of a solar-specific profile could better represent the actual system marginal energy benefits associated with incremental solar generation as opposed to the generic energy rate that assumes equal production in all hours.

Witness Snider disputed Public Staff witness Hinton's claim, that solar off peak rates would increase between 8% and 10% due to the diurnal profile of solar coinciding with higher off peak hours. Witness Snider testified that Duke had analyzed producing an avoided energy rate under the traditional peaker method, but altered to include only a daylight hours solar load shape using a free 100 MW solar load profile to generate the associated energy, rather than a constant

100 MW as traditionally used in calculating the standard offer energy rate design. Based on this analysis, he testified that a solar-specific energy rate that more precisely calculates the energy value of incremental solar based on the load characteristics of a solar resource would result in avoided energy rates that on an annual average would be approximately 10% lower than the rates solar QFs are receiving under the generic small QF standard offer that assumes constant energy production around the clock.

Witness Snider then discussed the factors that led to a lower avoided energy cost rate using a solar-specific profile. First, he noted that the non-coincident nature of the solar shape with Duke's loads contributes significantly to the lower rate. He pointed to his Figures 7 and 8 in his rebuttal testimony. Figures 7 and 8 illustrate that peak load typically occurs between 7 AM and 8 AM in the winter (January) and between 4 PM and 5 PM in the summer (July). The peak for solar output typically occurs between 1 PM and 2 PM in the winter and between 2 PM and 3 PM in the summer. Witness Snider highlighted that on winter mornings, solar generation starts providing energy to the system just as load is decreasing. During winter evening hours, solar output begins to decline just as load is rebounding. He then testified that solar aligns better with load in the summer, but solar output still begins to decline as system demand is growing toward the afternoon peak. Witness Snider pointed out that solar resources are only available on a varying basis in approximately 55% of all hours in the year. In addition, solar generation only moved in the same direction as load about half those hours while moving in the opposite direction the other half. Figures 7 and 8 show that solar is moving in the opposite direction of customer demand during critical peak hours when energy demand is peaking. Witness Snider then addressed Figures 9 and 10 in his rebuttal testimony, which show that as more solar is added to the system, the more non-coincident the solar shape becomes versus the load profile.

Witness Snider further testified that because a solar profile is not coincident with load, it lacks coincidence with Duke's highest marginal cost hours in both winter and summer. Witness Snider's Figures 11 and 12 illustrated that solar is not producing at high levels during the Companies' highest system marginal costs. These Figures also depicted that solar is not fully available during the Option B on-peak hours for non-summer months. Witness Snider testified that the current energy rate structure, which provides solar with a rate based on a flat 100 MW load profile, effectively over-credits solar QFs for energy during the on-peak hours.

With respect to the capacity value of solar, witness Snider stated that Duke would strive to align the capacity rate paid to solar with the amount of avoided capacity that the solar resource will produce. To that end, the Companies would account for the unique characteristics of a large-utility scale solar-specific QF on the system outside of the standard QF rate offering. Witness Snider noted that a solar QF is intermittent, non-dispatchable, and not capable of following customer load. Moreover, witness Snider continued, during high demand periods, solar is ramping up when peak loads are declining and declining when customer demand is increasing. Witness Snider concluded that, as NCSEA witness Johnson had suggested, using a solar-specific load profile to calculate negotiated QF rates along with a potential change in subsequent biennial avoided cost proceedings will provide more precise price signals to QFs that reflect the specific characteristics of the QF as envisioned by PURPA.

On cross-examination by Cypress Creek, witness Snider testified that Duke views it as appropriate to include costs associated with solar QFs in negotiated PPAs that they do not include in standard offer PPAs. Witness Snider testified that the currently proposed avoided cost rates in the standard offer are technology agnostic, but that it may be appropriate with the larger QFs to account for the specific characteristics of that QF. He clarified that Duke was not proposing to include an ancillary service charge in the standard rates in this proceeding as Duke proposed in Sub 140, Phase I, but he noted that it would be appropriate to consider evaluating, including such ancillary costs, outside of the standard offer. On examination by the Attorney General, witness Snider testified that PURPA contemplates a solar-specific rate, wherein the attributes of that specific technology are included in the rate can be appropriate. Witness Snider also noted that the amount of capacity that a utility could actually avoid building as a result of a generic QF is very different from how much capacity a solar QF avoided. Witness Snider concluded that the standard offer rates, as filed, still paid very well for capacity, even though very little capacity will actually be avoided through additional solar QFs. Thus, witness Snider indicated that if Duke adopted technology-specific avoided cost rates, those are areas that will need to be addressed for large QF negotiations to more appropriately value the QF's capacity and energy.

Witness Petrie testified that in determining the rates it is proposing in this case, Dominion used the same Black-Scholes Model option pricing method to determine fuel hedging benefits that was proposed by the Public Staff in the 2014 biennial proceeding. He also noted that, while Dominion believes there are likely costs associated with integration of distributed solar generation, it did not include solar integration costs in its production cost modeling.

In response to witness Johnson's testimony, witness Gaskill testified that Dominion has incorporated in its avoided cost rates those avoided costs that are reasonably known and quantifiable, including for avoided energy, capacity, line losses, and congestion. He testified that it is only now, in the absence of those benefits as QF generation has exceeded load and those benefits are reduced or eliminated, that Dominion has proposed to reduce or eliminate the associated costs from its standard avoided cost rates. He noted that Dominion shares Public Staff witness Hinton's concern regarding the uncertainty of integration costs, but since its integration costs studies have not yet quantified those costs, it has not proposed to include any integration costs into its avoided cost rates at this time.

Public Staff witness Hinton testified that in the Sub 140 proceeding, NCSEA witness Tom Beach proposed that the definition of off-peak hours be aligned with the load profile of solar QFs. The Commission did not adopt this proposal on the basis that it accounted for the benefits but not the costs associated with solar generation. Witness Hinton asked the Commission to view this issue as a modeling or allocation issue where solar generation during off-peak hours is not being properly valued in rates. His calculations indicate that the avoided energy rate for solar would be 8% to 10% higher if the avoided marginal costs from solar generation during off-peak hours were taken into account. Witness Hinton recommended that the utilities submit a solar-only rate.

Discussion and Conclusions

Several parties' witnesses suggested that a "solar-specific rate" would be appropriate for consideration in the next biennial avoided cost proceeding. In Order No. 69, FERC explained that standard rates for purchase may differentiate among QF technologies on the basis of supply characteristics, while also recognizing that administrative efficiency of setting generic standardized avoided costs that do not take into account the specific characteristics of these small QFs is appropriate even if a deviation in value from true avoided costs results.

> [FERC] is aware that the supply characteristics of a particular facility may vary in value from that average rate set forth in the utility's standard rate required by this paragraph. If the Commission were to require individualized rates, however, the transaction cost associated with administration of the program would likely render the program uneconomic for this size of [QF]. Order No. 69, 45 Fed. Reg. at 12,223.

In describing the avoided costs rates to be paid to larger QFs, FERC also emphasized that a QF's capacity and energy supply characteristics could be taken into account in analyzing whether the QF provided capacity value and in calculating the incremental energy value to be avoided by the QF. Id. at 12,224 (describing the specific capacity value considerations of wind, solar, and biomass QFs). FERC also established specific factors that could affect the rates for purchases from QFs, while emphasizing that the selection of a methodology setting avoided costs is best left to the State Commissions charged with implementing PURPA's must-purchase provisions. Id. at 12,226; see 18 C.F.R. 292.304(e); see also Windham, at ¶6 (recognizing that the value of avoided energy and capacity could be lower for purchases from intermittent QFs than for purchases from firm QFs). Section 62-156(b) incorporates consideration of these factors as a part of the Commission's standards that apply to the standard offer contract rates for each electric public utility.

Based on the foregoing and the entire record herein, the Commission concludes that it is inappropriate to require the Utilities to develop a separate avoided cost rate for solar QFs in this docket. As witness Hinton notes, the Commission previously rejected this proposal on the grounds that it "isolates one potential benefit of solar generation, but fails to account for any of the potential costs inherent in such intermittent resources." Order on Inputs at 62. The Commission reaches the same conclusion here. Further, the Commission concludes that any technology specific rate is contrary to the direction in the federal regulations implementing PURPA and G.S. 62-156(b).

However, the Commission finds merit in the concept underlying the recommendations of witnesses Hinton, Johnson, and Snider, that an evaluation of the Utilities' avoided costs should consider the characteristics of the power supplied by a QF. Considering the factors in G.S. 62-156 and the FERC regulations in the determination of avoided cost rates ensures that the Commission's avoided cost methodology remains true to PURPA's directive that avoided cost rates are to be based on the costs that the utility avoids. Thus, the Commission recognizes that PURPA provides utilities with the ability to consider factors including the availability of capacity, the QF's dispatchability and reliability, and the value of the QFs' energy and capacity in establishing avoided cost rates for purchases from larger QFs, including solar QFs. The Commission also recognizes that in the past the Commission has required utilities to make the standard offer tariff available to QFs based upon the QF's fuel source or technology used to generate electricity, but that issue is distinct from the rate paid to the QF. The Commission concludes that this approach complies with PURPA and G.S. 62-156 and should be continued in future avoided cost proceedings. The Commission further concludes 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.

Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate to require the Utilities to calculate avoided energy and capacity costs for purposes of establishing rates available to QFs eligible for the standard offer without regard to the technology the QF uses to generate electricity. The Commission further finds 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.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 21

The evidence supporting these findings is contained in the proposed rates of WCU and New River. WCU and New River proposed to offer variable rates based upon their wholesale cost of power and long-term fixed price rates that track DEC's Commission-approved five, ten, and 15-year long-term avoided cost rates for QFs interconnected at distribution. This is the same approach approved by the Commission in Sub 140. No parties filed any comments or objections to WCU's and New River's proposals. DEC is WCU's requirements supplier, and it is indirectly New River's through Blue Ridge Electric Membership Corporation (Blue Ridge). The PPA between DEC and Blue Ridge expressly treats New River's native load as if it were Blue Ridge's native load for purposes of DEC's obligations vis-à-vis Blue Ridge.

As discussed above, amended G.S. 62-156 provides that long-term contracts up to ten years for the purchase of electricity by the electric public utility from small power producers with a design capacity up to and including 1,000 kW (or 1 MW) shall be encouraged to enhance the economic feasibility of these facilities.

The Commission concludes, based upon the foregoing and the entire record herein, that WCU's and New River's rate proposals should be altered to conform with amended G.S. 62-156, namely, that WCU and New River should eliminate the 15-year long-term rate option and with the other changes approved herein with respect to DEC's avoided capacity and energy rates. Therefore, WCU's and New River will be required to file amended schedules reflective of these changes as part of the compliance filing required by this order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-25

The evidence supporting these findings of fact is found in the testimony of Duke witnesses Bowman and Freeman, Dominion witness Gaskill, Public Staff witnesses Lucas and Hinton, and NCSEA witness Harkrader.

Summary of the Testimony

Duke witness Bowman testified that the current standard to establish a LEO, as approved in the Sub 140 proceeding, requires the QF developer to take the following actions: (1) self-certify with the FERC as a QF; (2) obtain a CPCN from the Commission to construct the generator; and (3) indicate its intent to make a commitment to sell the facility's output under PURPA via the use of an approved Notice of Commitment Form. However, witness Bowman also testified that the current process is increasingly imposing unjust and unreasonable purchase obligations on Duke's customers without actually obligating the QF to sell to the utility. She further testified that this results from the QF being able to establish a LEO without actually obligating the QF to sell to the utility, essentially rending the "QF's 'commitment to sell' increasingly meaningless."

Duke witness Freeman testified in support of Duke's proposed changes to the LEO standard. He testified that his recent experience is that the commitment to sell purportedly being made by QFs who submit the Notice of Commitment Form is not meaningful or binding on the QF. Witness Freeman argued that the commitment to sell power under the current LEO standard is being made early in the development process when the QF (1) has no concrete information on the feasibility, cost, or timing of interconnection; (2) is not ready, willing, and able to sell power; and (3) has not begun PPA negotiations with the utility. Witness Freeman further argued that this is not consistent with PURPA's intent that a QF must make a legally enforceable commitment to sell – either through executing a PPA or under a non-contractual LEO where the utility refuses to enter into a contract – in order to obligate the utility and its customers to purchase the QF's output.

Witness Freeman next testified by describing some of the unique provisions of the North Carolina Interconnection Procedures (NCIP) approved by the Commission in May 2015 that impact whether a QF can make a reasonably informed commitment to sell early in the interconnection and QF development process. He noted changes to the study process, including the elimination of the initial feasibility study so that the System Impact Study (SIS) is now the first study completed. He testified that during the SIS process, the feasibility, grid impacts, and preliminary ballpark cost to interconnect the generator are analyzed. He further testified that as interconnected solar capacity has increased on DEP's rural distribution system, certain proposed points of interconnection either may not be feasible to interconnect additional solar without adversely impacting power quality and reliability, or the proposed generator must be significantly modified (i.e., a reduction in nameplate generator capacity) during the study process to make interconnection to the local distribution system feasible. In addition, he testified that increasingly, significant system upgrade costs are likely to be required, as the average upgrade cost for utility-scale generators exceeded $400,000 in 2016.

Witness Freeman further described the interdependency-driven interconnection processing under NCIP Section 1.8, which prioritizes studying generators whose proposed points of interconnection are not impacted by upgrades required to interconnect lower-queued generators. Currently, there are over 150 "On Hold" interconnection requests in DEC and DEP's North Carolina interconnection queues and 33 different substations where more proposed generators have submitted an interconnection request for study than can even be accommodated by the substation size, transmission, and/or distribution systems. Witness Freeman also identified how the interim interconnection agreement and "dwell period" between the SIS and Facilities Study are designed to allow QFs to continue with project development work, but emphasized that QFs are not required to make any binding commitments to proceed with the generator during the study phase of the interconnection process.

Witness Freeman testified that the first meaningful commitment by a QF developer under the Section 4 Full Study interconnection process occurs where the interconnection customer executes the interconnection agreement (IA) and financially commits to construction of system upgrades so projects later in the study queue (and the utility processing the studies) can rely on the required system upgrades being constructed. He testified that DEC and DEP have treated the

60 calendar day period provided in the NCIP for payment of upgrades as an informal due diligence period where the interconnection customer may terminate the IA without liability if the QF elects not to pay for upgrades under the IA and to terminate the project. Witness Freeman further testified to his recent experience that two to four years could pass between a Sub 140 "LEO date" established early in the QF interconnection and development process and the point in time that a QF begins delivering power to customers. This extended period heightens the risk and likelihood that the LEO-committed avoided cost rates no longer align with Duke's then-existing avoided costs, effectively assigning the risk of stale and inaccurate avoided costs to Duke's customers.

Witness Freeman testified that Duke initially proposed modifications to the current Notice of Commitment (NoC) Form intended to modify the current NoC Form to require a utility-scale QF developer proceeding through the Section 4 full study process to make some indicia of commitment by executing and returning a Facilities Study Agreement after the dwell period, thereby committing the project to a detailed engineering and construction Facilities Study. However, witness Freeman then testified that Duke modified its recommendation, and now supports the Commission transitioning the current LEO standard to formalized contracting procedures between larger QFs and the utilities, which will more appropriately align the establishment of a legally enforceable commitment to sell with the date upon which a QF actually agrees in a PPA to commit itself and becomes obligated to deliver power over a specified term. Witness Freeman testified that similar contracting procedures have been adopted in other jurisdictions with significant PURPA activity, including Oregon and Idaho, where a LEO commitment to sell is tied to the QF's commitment to deliver power under a PPA. For example, witness Freeman testified that, in Oregon, a LEO is established when a QF signs a final draft of an executable PPA that includes a scheduled commercial on-line date and information regarding the QF's minimum and maximum annual deliveries, thereby obligating itself to provide power or be subject to penalty for failing to deliver energy on the scheduled commercial on-line date. He argued that adopting similar contracting procedures here could resolve Duke's concerns about the growing harm to customers of stale avoided cost rates, while also providing QFs certainty as to the process for negotiating a definitive PPA. This proposal, he also argued, would better ensure that the QF developer and not Duke's customers is taking on the risk of the QF's non-performance at the time the QF's "commitment to sell" is made. Witness Freeman emphasized that customers should be protected from the risk of the QF's potential non-performance by including reasonable and appropriate liquidated damages (if the QF is late in achieving commercial operation) or termination damages (if the QF elects not to perform) in negotiated PPAs for large QFs. He noted that if the QF and the utility cannot agree to a PPA, the QF could also file a complaint or petition for arbitration with the Commission.

Witness Freeman also testified regarding the expedited Fast Track study process for smaller generators, and stated that Duke supports a streamlined LEO form for small QFs 1 MW or less that are eligible for the standardized avoided cost rates and terms and conditions. The streamlined form would consist of: (1) submission of a Report of Proposed Construction to the Commission under Rule R8-65; (2) submission of a Section 2 or Section 3 Interconnection Request, which the Company deems complete; and (3) indication of intent (i.e., a notice of commitment) to sell the QF's output to DEC or DEP under then-approved standard avoided cost rates.

Finally, witness Freeman testified regarding potential changes to the process for negotiating PPAs between large QFs and the Utilities. Witness Freeman testified that the proposed contracting procedures are commercially reasonable and will improve the transparency and efficiency of the negotiated PPA process by establishing clear milestones and a process for good faith negotiations between the QF and utility. He also testified that the contracting procedures modify the process for a large QF to make a legally enforceable commitment to sell by focusing on the QF's commitment to enter into a PPA as establishing its obligation to deliver energy or capacity over a specified term. Under his proposed contracting procedures, he argues that the decision to make such a commitment is completely within the QF's control, and only where the QF and the utility cannot agree on the terms and conditions of the PPA would the Commission need to get involved to determine whether a non-contractual LEO has been established. Prior to the QF entering into a PPA, he suggests that the utility will provide non-binding indicative avoided cost pricing that may be used by the QF developer to make determinations regarding project planning, financing, and feasibility of the proposed QF project. This approach, he argues, mitigates the risk of stale avoided cost rates as the QF will be provided indicative pricing information needed to evaluate developing the QF, but will not "lock in" avoided cost rates until it actually makes a commitment to deliver power to the utility over a specified term by executing a PPA. Witness Freeman also suggested that the Companies' PPA would continue to include a 60-calendar day "post-execution due diligence period," providing the QF reasonable additional time to ensure it is prepared to make a legally enforceable commitment to sell power over the term specified in the PPA.

Witness Freeman included as an exhibit to his testimony a revised Notice of Commitment Form proposed to be used by QFs smaller than one MW. Witness Freeman also included a Notice of Intent to Negotiate Form and contracting procedures to be used by larger QFs as an exhibit to his testimony and requested that the Commission direct Duke to take input from the Public Staff, Dominion, and other interested parties on the large QF form.

Dominion witness Gaskill described the current requirements for a QF to establish an LEO under the 2014 biennial proceeding orders: receive a CPCN or Report of Proposed Construction; be a QF; and submit a "Notice of Commitment" form, which Dominion calls the LEO Form. Witness Gaskill testified that, while Dominion did not initially recommend changes to the standard for establishing a LEO, he shares many of the same concerns raised by the Duke witnesses. He testified that the current LEO process, while improved in the 2014 biennial proceeding with the determination of a uniform LEO Form and the addition of the QF status requirement, still allows a QF to establish a LEO before it is in a position to truly commit to develop the project and deliver power in a timely manner. He further testified that, in practice, the LEO Form has been used by North Carolina QFs as a means to establish a put-option price, but it has not obligated the QF to actually deliver power to the utility.

Witness Gaskill testified that this situation presents two significant implications, both of which unjustly harm customers. First, he testified that it impairs adequate utility system planning, because Dominion does not know how much QF power will ultimately be constructed and delivered, since it cannot rely on the QF energy and capacity to be available based on an LEO. As a result, he testified that Dominion must, in order to meet its obligation to meet customer requirements, secure short- and long-term capacity without accounting for QFs, thus reducing or eliminating any avoided capacity costs. Second, he testified that the current process has created a situation where the LEO, and thus the avoided cost prices, are significantly outdated by the time the QF actually completes construction and begins delivering output. He testified that the result is that customers are paying rates to QFs that established LEOs and therefore qualified for avoided cost rates that, in many cases, were calculated years prior to the QF actually coming online.

Witness Gaskill argued that Duke's proposed LEO process would better align a QF's commitment to the point in time at which it can be reasonably sure whether it will proceed with the project. He agreed that Duke's proposal for small QFs 1 MW or less is a reasonable step to ensure that the QF is in fact progressing in its development. He also agreed that either of Duke's initial proposals for large QFs—establishing the LEO after execution and return of a Facilities Study Agreement, or tying the LEO to the negotiated PPA process—would be an improvement over the current process, because they also better align the LEO with the point in time at which the QF has enough information to actually commit to development. Witness Gaskill testified that witness Lucas' recommendations for the large QF standard would still allow QFs to establish an LEO before they have made any material financial commitments beyond the interconnection fee or actual commitment to delivery output to the utility, but stated that he did not object to these recommendations as they are an improvement over the current process, assuming that the requirement to obtain a CPCN or RPC would remain in place.

Finally, witness Gaskill testified that although Dominion did not submit a modified LEO Form, he believes that the LEO requirements should be uniform for all QFs in the State regardless of the utility to which the QF interconnects. He stated that, once the Commission determines any changes to the requirements for an LEO in this proceeding, Dominion would work with the Public Staff, Duke, and other stakeholders on the appropriate modifications to the LEO Form to implement those requirements.

Public Staff witness Lucas agreed with Duke's streamlined LEO process for small QFs of one MW or smaller. Witness Lucas also proposed to include an additional requirement to the current LEO standard for non-standard QFs. He proposed that in order to establish a LEO, the QF must first be a Project A or B in the interconnection queue. The LEO would be established upon the earlier of (1) the QF's receipt of the utility's SIS, or (2) the passage of 105 days after the QF submits a complete interconnection request to the utility. For QFs that are not a Project A or B at the time the QF submits its interconnection request, the LEO is established upon the earlier of (1) receipt of the utility's SIS for the QF, or (2) 105 days after the QF becomes a Project A or Project B.

Witness Lucas largely agreed that a QF owner lacks the ability to fully evaluate the feasibility of a project until it receives its SIS results. However, witness Lucas pointed out that the timing and control of the interconnection process is also largely up to the utility. Under the NCIP, a utility has 105 days to provide a QF with a SIS. With the current delays in the interconnection queue, he testified that the actual time required for these studies has varied with some projects waiting far longer than 105 days for receipt of the study. Moreover, he testified that the QF has no control over when it will receive its SIS because the timing of the study is solely in the hands of the utility. Thus, he concluded that tying the establishment of the LEO to completion of the System Impact Study step of the interconnection process as proposed by Duke would allow the utility to determine if and when a LEO is established. This, witness Lucas testified, would be inconsistent with FERC's decision in FLS Energy, Inc., which held that allowing the utility to control whether or not a LEO is established is contrary to PURPA and FERC regulations.[1]

Witness Lucas also proposed to limit QFs that withdraw a previously submitted NoC from being able to establish a new LEO for two years from the date of withdrawal. He testified that in an environment of rising avoided costs, this would prevent a QF from delaying the establishment of a LEO in order to take advantage of higher rates. Under his proposal, for the two-year time period after a QF has withdrawn its NoC, the QF would be limited to the utility's "as available" energy rates.

Public Staff witness Hinton testified that the Public Staff generally agrees with witness Freeman's testimony regarding the establishment of reasonable contracting procedures that improve the transparency and efficiency of the negotiated PPA process. Witness Hinton recommended Duke provide additional details regarding its proposal, and specifically highlighted his support for certain standards including providing for specific timeframes for both parties to provide information and responses; providing for a standardized contract form with clear delineation of any specific changes or points of negotiation clearly identified; providing for the utility to deliver indicative pricing for a sufficient period of time to allow the QF to evaluate the viability of its project and be able to seek financing; and providing an opportunity for either party to seek informal resolution of disputes or to petition for arbitration with the Commission.

NCSEA cites the federal regulations, FERC's decisions in J.D. Wind and FLS Energy, and the Commission's Order Denying Request for Waivers, issued on June 15, 2005, in Docket No. SP-4158, Sub 0, in support of its opposition to Duke's proposed changes to the standard for establishing a LEO. In short, NCSEA objects to Duke's proposal because it leaves the QF's ability to establish a LEO outside of the QF's control. NCSEA witness Harkrader testified to the unpredictability and inconsistency that plagues the interconnection process and that, in her experience, the interconnection process now takes longer and is less predictable than prior to the May 2015 revisions to the NCIP. She testified that in 2016, her company Carolina Solar Energy II, LLC (CSE) was involved in the interconnection of 12 5-MW_{AC} solar QFs to the grid. Witness Harkrader projects that in 2017, only four 5-MW_{AC} solar QFs developed by CSE will be interconnected. Further, she testified that one interconnection request made by CSE in the summer of 2014 has still not received results from the study process and that CSE has received only one new SIS from the utility for a distribution level QF in North Carolina in the past twelve (12) months.

NCSEA also takes issue with Duke's assertion that a QF cannot make a commitment until it receives the results of the SIS. NCSEA witness Harkrader testified that the QF development process involves many steps that require the QF to make significant commitments, only one of which is interconnection. She testified that: 1) the early stages in the development process involve the identification of a suitable site for the facility, the negotiation for site control with the landowner, the completion of environmental surveying and permitting, the securing of land use approvals, and the securing of regulatory approvals; 2) these early stages can take many months, or longer, to complete; and 3) securing rights to the site and all necessary approvals involves significant costs. She further testified that the interconnection process involves significant

[1] See, In re: FLS Energy Inc., 157 FERC 61, 211 (December 15, 2016).

commitment on the part of the QF. Specifically, she testified that the interconnection request is typically made very early in the process after site control has been secured. Engineering and design work must be undertaken prior to submitting the interconnection request, and a significant fee, $25,000, in the case of a 5-MW QF, must be paid at the time the interconnection request is submitted. Subsequent to the submittal of the interconnection request, a scoping meeting is held with the relevant personnel for the interconnecting utility, as well as the QF's team of engineers, to discuss the request. From the scoping meeting, the request proceeds to the study process. The process of preparing an interconnection request, submitting to the utility, and holding a scoping meeting with the utility can take several months and involve significant expense, depending on the complexity of the interconnection and the engineering and design resources required. Thus, witness Harkrader testified that significant commitments—in terms of expenditure of time and financial resources and the securing of necessary approvals—are made toward the development of the QF before the interconnection study process is completed. Based upon witness Harkrader's testimony, NCSEA agrees with the Public Staff's proposal to amend the LEO standard, by providing that the LEO could be established at the earlier of the completion of the SIS or 105 days after the date of the submittal of the interconnection request.

Discussion and Conclusions

A QF has the unconditional right to choose whether to sell its power "as available" or pursuant to a LEO at a forecasted avoided cost rate determined, at the QF's option, either at the time of delivery or at the time that the obligation is incurred. 18 C.F.R. 292.304(d). PURPA requires that a utility purchase any energy and capacity made available by a QF. 18 C.F.R. 292.303(a). Use of the term "legally enforceable obligation" is intended to require the QF to make a commitment to sell as well as to prevent a utility from circumventing PURPA's requirements merely by refusing to enter into a contract with the qualifying facility, Order No. 69 at 12,224, or by delaying the signing of a contract, so that a later and lower avoided cost is applicable. Cedar Creek Wind, LLC, 137 FERC ¶ 61,006 at p. 5 (2011). By committing itself to sell to an electric utility, a QF also commits the electric utility to buy from the QF, resulting in either a contract or in a non-contractual, but binding, legally enforceable obligation. J.D. Wind at 25. FERC has held: "the establishment of a LEO turns on the QF's commitment, and not the utility's actions." (emphasis in original). FLS Energy, at 9, citing J.D. Wind at 25[1]. More specifically, "a requirement for a facilities study or an interconnection agreement, given that the utility can delay the facility study or tendering an executable interconnection agreement, as a predicate for a legally enforceable obligation is inconsistent with PURPA," FLS Energy at 8. The Commission notes that on June 29, 2016, FERC held a technical conference to review PURPA,[2] and that Congress is

[1] In FLS Energy, the QFs at issue had already tendered PPAs at the time they alleged LEOs were established. In FLS Energy, the FERC denied the QF's request to undertake an enforcement action thereby arguably rendering its statements interpreting PURPA's LEO standard dictum.

[2] See Implementation Issues Under the Public Utility Regulatory Policies Act of 1978; Supplemental Notice of Technical Conference, 81 Fed. Reg. 43593 (July 5, 2016).

conducting an examination of PURPA that might result in legislation proposing modifications of this 1978 statute.[1]

The Commission acknowledges the testimony of Duke witness Freeman and Public Staff witness Lucas, that delays in the interconnection queue have allowed QFs to establish a LEO well before the date the QFs are able to generate power. The Commission agrees that this delay can expose the utility to a risk of being obligated to pay avoided cost rates that deviate from the utility's actual avoided costs and that delays in the interconnection queue have added to this risk. The Commission agrees with the Public Staff that the appropriate refinement to the standard for establishing a LEO is one that brings the LEO date into closer alignment with the date the QF is able to deliver power to the utility.

Therefore, the Commission finds it appropriate, for the purposes of this case, to add an additional requirement to the current LEO standard for QFs larger than one MW, as a step in the direction of reducing the impact of paying QFs on the basis of stale rates. For these QFs, a LEO is established when (1) the QF has self-certified with FERC as a QF, (2) the QF has made a commitment to sell the QF's output to a utility under PURPA using the approved NoC Form, (3) the QF has filed a report of proposed construction or been issued a CPCN pursuant to G.S. 62-110.1, and (4) the QF has submitted a completed interconnection request pursuant to the NCIP. For a QF that has been designated as an A or B project in the interconnection queue, the date on which the LEO is established shall be the earlier of (1) 105 days after the submission of the interconnection request, or (2) upon the receipt of the system impact study from the public utility. For a QF that has not been designated as an A or B project at the time of its interconnection request, the date on which the LEO is established shall be the earlier of (1) 105 days after the project has been designated as an A or B project, or (2) upon the receipt of the system impact study from the public utility. In either case, where the QF has or has not been designated an A or B project, the 105-day period as part of establishing a LEO will remain in effect until the Commission issues a final order in Docket No. E-100, Sub 101. If, by final order issued in that docket, the Commission alters the NCIP's 105-day-deadline for providing a QF with the results of the utility's system impact study, that altered deadline shall be substituted for the 105-day standard approved in this order. If, prior to the expiration of the 105 days or the substituted date from Docket No. E-100, Sub 101, the utility anticipates being unable to deliver the results of the system impact study to the QF, then the utility may petition the Commission for an extension of that deadline and a delay in the establishment of the QF's LEO. In the proceeding on such a petition, the utility shall bear the burden of proof to justify any requested extension and delay, and the length thereof. The Commission shall address such petitions on an expedited basis and determine the appropriate deadline extension and LEO date on a case-by-case basis. This procedure places the timing of the LEO under the supervision and control of the Commission with appropriate safeguards to prevent the utility from unilaterally delaying the establishment of the LEO so as to prevent the QF from obtaining a valid PPA. The Commission concludes that these refinements fully comply with PURPA's requirements by establishing the LEO based on the QF's commitment and independent

[1] See Powering America: Reevaluating PURPA's Objectives and its Effects on Today's Consumers Before the Subcomm. on Energy of the H. Comm. on Energy and Commerce, 150th Cong. (2017).

of the utility's actions. The Commission further concludes that these changes, in conjunction with the other changes approved in this order, tend to mitigate the lag time between the date the LEO is established and the date the QF delivers power to the utility, which in turn, supports PURPA's goal of setting avoided cost rates that reflect the utility's avoided costs.

For QFs with a generating capacity less than one MW and eligible for the standard offer contract, the Commission agrees with witness Freeman that changes to streamline the process are appropriate. For these QFs, a LEO is established when (1) the QF submits a report of proposed construction to the Commission pursuant to G.S. 62-110.1 and Commission Rule R8-65; (2) the QF submits a Section 2 or Section 3 Interconnection Request; and (3) the QF has made an indication of intent (i.e., a notice of commitment) to sell the QF's output to the utility under then-approved standard avoided cost rates. These proposals were generally supported by the Public Staff witnesses, and no parties opposed or requested changes to the NoC Form included as an exhibit to witness Freeman's testimony.

The Commission also acknowledges the Duke witnesses related concerns of "stale rates" and a QF establishing a LEO without making a true commitment to sell power to the utility. The concern they expressed is that the rates for which a QF is eligible at the time it establishes a LEO may no longer be representative of the utility's current avoided costs at the time the QF begins delivering power to the utility. Public Staff witness Lucas agreed with many of these concerns and proposed a modification to the NoC to limit a QF to "as available" energy rates for a period of two years should a QF withdraw its NoC Form. In addition, witness Lucas pointed to a provision in Duke's current standard contract terms and conditions that limits eligibility to QFs that begin delivering power within 30 months of establishing a LEO and the automatic termination provisions in the current NoC Form as providing a utility's ratepayers with protection against stale rates. The 30-month provision was first approved in the 2012 avoided cost proceeding (Docket No. E-100, Sub 136) and no party has proposed a change or requested Commission review of that provision in this proceeding. The Commission finds that the Public Staff's proposal to limit a QF that withdraws its commitment to sell to "as available" rates for the two years following the withdrawal to be an appropriate protection against stale rates. Therefore, the NoC Form should be revised to reflect the consequences of withdrawing a previously submitted NoC Form. The Commission concludes that this revision, the existing 30-month provision in the standard contract terms and conditions, and the existing automatic termination provisions in the NoC, provide appropriate incentives to QFs to make a commitment to actually deliver power to a utility.

Finally, the Commission finds it appropriate, as recommended by the Public Staff, to establish a forum to develop procedures for the negotiation of non-standard PPAs. In addition, the Commission finds that the issues discussed in this section merit further consideration. Therefore, the Commission will require the Public Staff to convene a working group that includes Duke, Dominion, and other interested stakeholders with the goal of developing consensus around proposed revisions to the NoC Form, procedures for streamlining the negotiated PPA process, and refinements to the standard for establishing a LEO that require a QF to make a more meaningful commitment to actually deliver power to the utility. The participants jointly, if consensus is reached, or individually, if not, should bring these matters to the Commission's attention in an appropriate proceeding, for example, the next biennial avoided cost proceeding or the interconnection stakeholder effort underway in Docket No. E-100, Sub 101.

Based upon the foregoing and the entire record herein, the Commission finds it appropriate to refine its standards for establishing a LEO as described in this section. The Commission will require the Utilities to solicit input on the revised NoC Form, make revisions to the form consistent with this order and the input received, and to file a revised form with the Commission as a part of the compliance filing required by this order.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC, DEP, and Dominion shall offer long-term levelized capacity payments and energy payments for ten-year periods as standard options to all QFs contracting to sell one MW or less capacity. The standard levelized rate option shall include a condition making contracts under those options 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 Dominion 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 Sub 106 Order. Dominion shall revise Schedule 19-LMP to provide that the energy price that it will pay pursuant to that rate schedule is the LMP at the PJM-defined nodal location nearest to where the energy is delivered.

3. That DEC, DEP, and Dominion 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 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, DEP, and Dominion shall calculate avoided capacity rates 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;

5. That DEC and DEP shall 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;

6. That DEC, DEP, and Dominion shall, in future avoided cost proceedings, propose commodity price forecast methodologies that are consistent with those proposed in the utility's most recently filed IRP;

7. That DEC and DEP should recalculate their avoided capacity rates using seasonal allocation weightings of 80% winter and 20% summer;

8. That DEC, DEP, and Dominion, shall use a PAF of 1.05 in their avoided cost calculations for all QFs other than hydroelectric QFs with no storage capability and no other type of generation;

9. That DEC, DEP, and Dominion, 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;

10. That Dominion shall eliminate the line loss adder of 3% from its standard offer avoided cost payments to solar QFs on its distribution network;

11. That DEC and DEP shall continue to include the line loss adder in their avoided cost calculations, but shall study the effects of QFs on their distribution grid to determine the extent of backflow at substations;

12. That DEC, DEP, Dominion, WCU, and New River shall, within 30 days of the date of this order, make a compliance filing in this docket that includes the following:

a. Revised schedules applicable to the purchase of power from QFs, in redline and clean versions, that comply with the rate methodologies and contract terms approved in this order;

b. Supporting calculations for the revised rate schedules applicable to the purchase of power from QFs;

c. Revised purchase power agreements and terms and conditions, in redline and clean versions, that comply with the contract terms and conditions approved in this order for the standard offer contract for purchase of power from QFs;

d. A short and plain explanation of the standard for a QF to establish a LEO, as approved in this order, and a description of how the utility will make this information available to QFs and the general public, including publication on the utility's website; and

e. Revised Notice of Commitment Forms that comply with the changes approved in this order.

13. That the revised rate schedules, purchase power agreements, and terms and conditions required to be filed by ordering paragraph 12 shall become effective and be implemented 15 days after being filed unless a party files with the Commission specific objections as to the accuracy of the revisions or supporting calculations;

14. That DEC, DEP, and Dominion shall, within 90 days of the date of this order, file with the Commission procedures stating how they would curtail electric output from QFs on a nondiscriminatory basis when the utility is faced with a system emergency;

15. That DEC, DEP, Dominion, and the Public Staff shall, within 90 days of the date of this order, convene a working group that includes other interested parties to discuss and develop streamlined contracting procedures for QFs contracting to sell capacity greater than one MW, further refinements to the Commission's LEO standard, and any other related issues, and, after considering the input of this working group, jointly or individually file with the Commission proposed forms and contracting procedures, or otherwise bring proposals to the Commission's attention through an appropriate proceeding;

16. That, in addition to their cost data and any other usual and appropriate matters, DEC, DEP, and Dominion shall, in their initial filings in the Commission's next biennial proceeding established to determine avoided cost rates for electric utility purchases from QFs, address the following issues consistent with the discussion and conclusions in this order: a continued evaluation of capacity benefits of QF generation, whether the utilization of a 2.0 PAF as approved in the Hydro Stipulation should continue as provided in that agreement, the effect of distributed generation on power flows on each utility's distribution system and the extent of power backflows at substations, hourly CT operational data and marginal cost data on a season-specific basis, and consideration of a rate design that considers factors relevant to the characteristics of QF-supplied power that is intermittent and non-dispatchable;

17. That WCU 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 ten-year, long-term avoided cost rates for QFs interconnected at distribution are approved. WCU's and New River's compliance filings shall reflect the changes the Commission has approved herein to DEC's proposed ten-year avoided capacity rates; and

18. That the proposed schedules, supporting calculations, and purchase power agreements and terms and conditions, except as specifically addressed in this order, are approved and shall be implemented.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of October, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

Commissioners Bryan E Beatty and Don M. Bailey did not participate in this decision.

DOCKET NO. E-100, SUB 149

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2016 REPS Compliance Plans and 2015 REPS Compliance Reports	))))	ORDER APPROVING 2015 REPS COMPLIANCE REPORTS AND ACCEPTING 2016 REPS COMPLIANCE PLANS

BY THE COMMISSION: North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS), codified at G.S. 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. General Statutes Section 62-133.8(c) sets out the percentage requirements that apply to electric membership corporations (EMCs) and municipalities that sell electric power to retail electric power customers in North Carolina, and provides the options available to these EMCs and municipalities for meeting the REPS requirements. These options include generating electric power at a new renewable energy facility, reducing energy consumption through the implementation of demand side management (DSM) and energy efficiency (EE) measures, and purchasing renewable energy certificates (RECs) derived from in-state and out-of-state renewable energy facilities. Pursuant to 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 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 measurement and verification 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 23, 2016, and September 12, 2016, the following electric power suppliers or compliance aggregators filed their respective 2015 REPS compliance reports and 2016 REPS compliance plans in this docket: Town of Fountain (Fountain); EnergyUnited EMC (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; Fayetteville Public Works Commission (Fayetteville PWC);

GreenCo Solutions, Inc. (GreenCo), on behalf of its member cooperatives and three other electric power suppliers;[1] Halifax EMC(Halifax),[2] the Tennessee Valley Authority (TVA), on behalf of itself, Blue Ridge Mountain EMC, Mountain Electric Cooperative, Murphy Electric Power Board, and Tri-State EMC (collectively, the TVA distributors); and the town of Waynesville (Waynesville).[3]

On January 6, 2017, the Commission issued an Order Establishing Dates for Comments on REPS Compliance Plans and REPS Compliance Reports.

On February 14, 2017, as updated and corrected on February 22, 2017, the Public Staff filed comments addressing the following: the 2015 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 2016 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 cost cap. Based on its review of the compliance reports, the Public Staff concludes that each EMC and municipal electric power supplier met its 2015 REPS requirements within the annual spending limit.[4] Based on its review of the compliance plans, the Public Staff concludes that each of the plans filed by the EMCs and municipal electric power suppliers (or their REPS compliance aggregators) contains the information required by Commission Rule R8-67(b) and indicates that the EMC and municipal electric power suppliers will achieve the general REPS requirements and the solar set-aside requirements in 2016. However, the Public Staff states that the majority of the EMC and municipal electric power suppliers do not expect to be able to meet the swine and poultry waste set-aside requirements during the planning period. The Public Staff concludes its comments by recommending the following: 1) that the Commission approve the 2015 REPS compliance reports, 2) that the Commission find that the 2016 REPS compliance plans indicate that the municipal and EMC electric power suppliers should be able to meet their REPS requirements, with the exception of the

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[1] In its compliance report, GreenCo 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 EC, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union EMC, d/b/a Union Power Cooperative, and Wake EMC. In addition, GreenCo 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 are included with those of Oak City.

[2] The Commission addresses Halifax EMC's 2015 compliance report by separate order issued contemporaneous with this order.

[3] In its filing, Waynesville states that prior to 2016, Waynesville was served under a wholesale power agreement with Duke Energy, which included purchasing or generating RECs on behalf of Waynesville; however, Waynesville further states that the wholesale power contract expired at the end of 2015, so beginning in 2016 Waynesville will be responsible for its own compliance. Accordingly, Waynesville filed in this docket a 2016 REPS compliance plan, but not a 2015 REPS compliance report.

[4] Due to rounding, there are minor discrepancies between the number of RECs that the Public Staff states are required for REPS compliance and the number that were actually submitted by several electric power suppliers. The Commission has noted similar discrepancies in the past and makes clear that an electric power supplier must always round up to the next whole REC in calculating its REPS obligations.

swine and poultry waste set-aside requirements, during the planning period without nearing or exceeding the cost cap, and 3) that the Commission adopt other specific recommendations as addressed below.

On March 1, 2017, GreenCo filed a letter stating its support for the Public Staff's recommendations.

REPS REQUIREMENTS FOR EMCS AND MUNICIPALITIES

For 2015, G.S. 62-133.8(c) requires that each EMC or municipality that sells electric power to retail electric power customers in the State meet the equivalent of six percent of its 2014 retail sales by using renewable energy or by reducing energy consumption through implementation of DSM or EE measures. Within this six percent requirement, each EMC and municipality must meet the requirements of the REPS by using a specified amount of renewable energy from solar, swine waste, and poultry waste resources. These EMCs and municipalities are permitted to incur incremental costs to comply with the REPS requirements up to the total annual limit established in G.S. 62-133.8(h)(3) and (4). As reflected in the following discussion, the Commission considered the 2015 REPS compliance reports and 2016 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 G.S. 62-133.8(d) for solar, subsection (e) for swine waste, and subsection (f) for poultry waste. For 2015, the solar set-aside requirements provide that each EMC and municipality shall supply 0.14 percent of its 2014 retail sales through the use of solar energy resources. For 2016, the solar set-aside requirement continues at 0.14 percent. Pursuant to the authority granted to the Commission in G.S. 62-133.8(i)(2), the 2015 swine and poultry waste set-aside requirements were modified and/or delayed by the Commission's Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief issued on December 1, 2015, in Docket No. E-100, Sub 113 (2015 Delay Order). The 2015 Delay Order further modified the swine and poultry waste set-aside requirements by delaying the 2015 swine waste set-aside requirements, and the scheduled increases in those requirements, for one additional year, by maintaining the 2015 poultry waste set-aside requirements at the same level as the 2014 requirement (170,000 MWh), and by delaying the scheduled increases in the poultry waste set-aside requirements by one year. Similar to the 2015 Delay Order, the Commission's Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief issued on October 17, 2016, in Docket No. E-100, Sub 113 (2016 Delay Order), modified the swine waste set-aside requirements by delaying the 2016 swine waste set-aside requirements and the scheduled increases by one additional year, and modified the 2016 poultry waste set-aside requirements by maintaining the 170,000 MWh requirement and delaying the scheduled increases by one year. Therefore, beginning in 2017, the electric power suppliers, in the aggregate, are required to comply with the REPS through the use of swine waste resources representing at least 0.07 percent of the total electric power sold and through the use of poultry waste resources representing 700,000 MWh of total electric power sold.

In its comments, the Public Staff states that all of the EMCs and municipalities met the solar set-aside requirements, but have been able to comply with the poultry waste set-aside requirements only to a "very limited extent." Further, the Public Staff states that these electric service providers will have "great difficulty" in complying with the swine waste set-aside requirements when it comes into effect. Nevertheless, the Public Staff opines that "the REPS statute has served as a stimulus for important advances in waste-to-energy technology." The Public Staff describes the stakeholder meetings that it hosted, at the Commission's request, to provide a forum for facilitating discussion on compliance with these set-aside requirements. The Public Staff states that the meetings were productive, and that it intends to hold more meetings in the future as requested by the Commission's 2016 Delay Order. The Public Staff concludes this section of its comments by stating that the Public Staff's view is that the lack of swine and poultry waste-to-energy facilities is the result of the following: 1) limited technology development and expertise due to the fact that currently North Carolina continues to be the only state with swine and poultry waste set-aside requirements; 2) the utilities' reluctance to commit to purchase contracts they deem too expensive for speculative technologies; 3) limited availability of satisfactory financing terms for developers; and 4) uncertainty over REC prices.

The Commission finds the Public Staff's comments helpful and requests that 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 EMC and municipalities' REPS compliance.

REPS Cost Cap

General Statutes Section 62-133.8(h)(3) and (4) limit an electric power supplier's annual REPS spending by providing that the total annual incremental costs to be incurred by an electric power supplier and recovered from the electric power supplier's customers shall not exceed an amount equal to the per-account annual charges applied to the total number of customers. "Incremental costs" means all reasonable and prudent costs incurred by an electric power supplier to comply with the REPS requirements that are in excess of the electric power supplier's avoided costs. G.S. 62-133.8(h)(1). For 2015, 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: $34 for each residential customer account; $150 for each commercial customer account; and $1,000 for each industrial customer account. 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 provided in G.S. 62-133.8(h)(3) and (4). The Public Staff notes, however, that some very small electric power suppliers, such as Fountain, are approaching the cost cap and might have difficulty meeting their REPS obligations while staying below the spending limit in the future. The Public Staff summarizes projected REPS incremental costs as compared to the future annual cost cap in Table 3 of its comments. The Public Staff's comments and the summary table indicate that each EMC and municipality is projected to be well below its respective spending limit through 2018.

The Commission recognizes the challenges small electric power suppliers face in meeting their REPS requirements while incurring incremental costs below the annual limit. Therefore, the Commission finds the Public Staff's comments helpful and requests that the Public Staff continue to file comments in future proceedings specifically addressing compliance with the REPS cost cap.

EECs from CFL Programs

General Statutes Section 62-133.8(c)(2) permits EMCs and municipalities to meet the REPS requirements by reducing energy consumption through the implementation of EE measures. An "energy efficiency measure" means an equipment, physical, or program change implemented after January 1, 2017, that results in less energy used to perform the same function. 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 an 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 (Order Approving 2014 REPS Compliance Reports). 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 its comments, the Public Staff discusses the broad range of EE programs that the municipal and EMC electric service providers use to meet their REPS requirements by reducing energy consumption. The Public Staff observes that only EnergyUnited, Fayetteville PWC, and GreenCo included EECs from CFL lighting measures in their respective 2016 compliance plans. The other municipalities and EMC's either did not include any EECs from CFL lighting measures or stated that they would no longer offer EE lighting programs. As reflected below, the Commission considered these programs in reviewing each of these electric power suppliers' 2015 compliance reports.

The Public Staff further states that lighting-related measures have been trending toward a light emitting diode (LED) baseline technology, and that since the time of the last REPS compliance filings, DEC and DEP have both been actively revising their current EE programs to utilize LED bulbs in place of CFL. Although CFL lighting measures have provided some electric power suppliers with a steady supply of EECs to meet their REPS compliance obligations for several years, the Public Staff asserts that these measures no longer promote energy efficiency as well as they once did and that EECs should only be produced from EE lighting measures that demonstrate a reduction in energy usage from the baseline lighting measure. The Public Staff argues that, as LED technology surpasses CFL technology, the changing baseline will remove CFL as an EE measure, rendering them obsolete. For these reasons, the Public Staff recommends that the Commission disallow the use of EECs for REPS compliance purposes that are associated with CFL installations on or after January 1, 2017. The Public Staff also recommends that the Commission require the EMCs and municipalities to utilize Duke Energy Progress Energy Efficient Lighting Program (PY2014) Evaluation Report – FINAL (DEP's 2016 EE Lighting Study) in determining the energy savings claimed after 2015 from CFL's installed before January 1, 2017.

The Commission addressed this, and related issues, in the Order issued on January 24, 2017, in Docket No. E-2, Sub 1109 (DEP REPS Rider Order), concluding that the Commission's proceedings held pursuant to G.S. 62-133.9 and the evaluation, measurement, and verification process required in those proceedings allows room for consideration of what baseline an

EE measure should be compared to in establishing the amount of reduced consumption. As in that proceeding, the Public Staff argues here that the "lighting market has been rapidly undergoing a new baseline shift," and that "this shift will continue to diminish the potential for new EECs from any CFL measure." Similar to the conclusions reached in the DEP REPS Rider Order, the Commission concludes that it is appropriate to require the municipal and EMC electric service providers to consider a new baseline for EE programs that use new lighting technology in their respective M&V processes. The Commission finds the Public Staff's recommendations on these issues helpful, but concludes that it is appropriate to allow the EMC and municipal electric power suppliers the flexibility to conduct the M&V studies without prescribing a specific study to be used. Therefore, in future REPS compliance proceedings, the Commission will require each EMC and municipal electric power supplier that is claiming EECs from lighting measures to address in its M&V study process whether a new baseline for lighting-based EE programs is appropriate. Those EMC and municipal electric service providers that are earning EECs from a lighting program that uses CFL, shall provide the Commission an explanation for the continued use of CFL that addresses the costs and benefits of the continuation of the program in light of the issues raised by the Public Staff.

Finally, the Commission finds the Public Staff's comments on these issues helpful and requests that the Public Staff continue to file comments in future proceedings specifically addressing the earning of EECs from lighting-based EE measures where EMCs and municipalities seek to use EECs derived from these measures to meet their REPS compliance obligations.

2015 REPS COMPLIANCE REPORTS

Each EMC and municipal electric power supplier (or its REPS compliance aggregator)[1] filed in this docket the 2015 REPS compliance report required by Commission Rule R8-67(c). In its comments filed with the Commission, the Public Staff reviewed and commented on each compliance report filed in this docket. Based on its review, the Public Staff states that all EMC and municipal electric power suppliers met the 2015 general REPS requirements of G.S. 62-133.8(c) and the 2015 solar set-aside requirements of G.S. 62-133.8(d). As reflected in Table 1 in the Public Staff's comments, the Public Staff concludes that the total 2015 incremental costs incurred by each EMC and municipality to meet its REPS requirements were below the total annual cost cap established by G.S. 62-133.8(h)(3) and (4). As discussed above, the Public Staff states that these EMCs and municipalities have been able to comply with the poultry waste set-aside requirements only to a limited extent, and that these EMCs and municipalities will have difficulty meeting the requirements of the swine waste set-aside requirements. As reflected in the following discussion, in determining whether each EMC or municipal electric power supplier met its 2015 REPS obligations and reporting requirements, the Commission reviewed and considered the 2015 compliance report filed by each EMC or municipal electric power supplier (or its compliance aggregator), the records in NC-RETS, and the Public Staff's comments.

[1] Waynesville was not required to submit a 2015 REPS compliance report. See fn. 3, supra.

EnergyUnited

On August 31, 2016, EnergyUnited filed its 2015 REPS compliance report. EnergyUnited's report demonstrates that EnergyUnited's 2014 total retail sales were 2,427,479 MWh; therefore, EnergyUnited's general REPS obligation of six percent of 2014 retail sales is 145,649 RECs, and its solar set-aside requirement, based on 0.14 percent of 2014 sales, is 3,399 solar RECs. Further, EnergyUnited's share of the 2015 poultry waste requirement is 3,100 poultry waste RECs. EnergyUnited's 2015 compliance sub-account in NC-RETS evinces that EnergyUnited met its 2015 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 EnergyUnited's compliance report and NC-RETS sub-account indicate that EnergyUnited met its REPS requirements for 2015. The Public Staff notes that EnergyUnited included EECs from two programs, the Commercial Lighting Program and the Heat Pump Rebate Program. The Public Staff agrees with the M&V results for these programs, and therefore, recommends that the Commission approve EnergyUnited's 2015 compliance report, including the M&V results for the EECs that EnergyUnited earned in 2015.

Based upon the foregoing and the record in this proceeding, including EnergyUnited's REPS compliance report, the data in EnergyUnited's 2015 compliance sub-account in NC-RETS, and the comments of the Public Staff, the Commission concludes that EnergyUnited complied with its 2015 REPS requirements, and therefore, the RECs and EECs in EnergyUnited's 2015 compliance sub-account in NC-RETS should be retired. The Commission further concludes that EnergyUnited's 2015 compliance report includes the information and supporting documentation required by Commission Rule R8-67(c), and therefore, EnergyUnited's 2015 compliance report should be approved.

Fayetteville PWC

On September 1, 2016, Fayetteville PWC filed its 2015 REPS compliance report. Fayetteville PWC's report demonstrates that Fayetteville PWC's 2014 total retail sales were 2,087,801 MWhs, and therefore, Fayetteville PWC's general REPS obligation of six percent is 125,268 RECs and its solar set-aside requirement, based on 0.14 percent of 2014 sales, is 2,923 solar RECs. Further, Fayetteville PWC's share of the aggregate poultry waste set-aside requirement for 2015 is 2,666 poultry waste RECs. Fayetteville PWC's compliance sub-account in NC-RETS evidences that Fayetteville PWC met its 2015 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 Fayetteville PWC's report and the data in Fayetteville PWC's 2015 compliance sub-account in NC-RETS indicate that Fayetteville PWC met its REPS requirements for 2015. The Public Staff further states that Fayetteville PWC did not use any EECs for REPS compliance in 2015, but is implementing five EE programs: 1) CFL Distribution Program, 2) LED Street Lighting Pilot Program, 3) Refrigerator Incentive Program, 4) HVAC Residential Program, and 5) Sustainable Sandhills Go Green Program. As stated in its report, Fayetteville PWC performed M&V and banked EECs for the LED Street Lighting Program, the HVAC Residential Program, and CFL Distribution Program, and used data from DEP and data from the Mid-Atlantic Technical Reference Manual. The Public Staff considers this acceptable data, but notes that the Order Approving 2014 REPS Compliance Reports requires electric power suppliers to use M&V studies no older than 2015 if the electric power supplier intends to earn EECs from a lighting-based EE program. Since Fayetteville PWC discontinued distribution of CFL bulbs, the Public Staff assumes that Fayetteville PWC does not intend to resume distributing CFL bulbs or claiming EECs from this program. The Public Staff further notes that Fayetteville PWC began providing LED bulbs for its CFL Distribution Program, but did not change the program name. The Public Staff suggests that the name of the program be updated to reflect the change to LED bulbs. Finally, the Public Staff recommends that the Commission approve Fayetteville PWC's 2015 compliance report.

Based upon the foregoing and the record in this proceeding, including Fayetteville PWC's REPS compliance report, the data in Fayetteville PWC's 2015 compliance sub-account in NC-RETS, and the comments of the Public Staff, the Commission concludes that Fayetteville PWC complied with its 2015 REPS requirements and therefore, the RECs and EECs in Fayetteville PWC's 2015 compliance sub-account in NC-RETS should be retired. The Commission further concludes that Fayetteville PWC's 2015 compliance report includes the information and supporting documentation required by Commission Rule R8-67(c), and therefore, Fayetteville PWC's 2015 compliance report should be approved. Finally, the Commission agrees with the Public staff that Fayetteville PWC should consider updating the name of its CFL Distribution Program to reflect the change to distributing LED bulbs. Therefore, the Commission directs Fayetteville PWC to address this matter in its 2016 compliance report and 2017 compliance plan.

Fountain

On August 23, 2016, Fountain filed its 2015 REPS compliance report. Fountain's compliance report demonstrates that Fountain's 2014 total retail sales were 3,486 MWh; therefore, Fountain's general REPS obligation of six percent is 210 RECs and its solar set-aside requirement of 0.14 percent is 5 solar RECs. Further, Fountain's share of the aggregate poultry waste set-aside requirement for 2015 is 4 poultry waste RECs. Fountain's 2015 compliance sub-account in NC-RETS evidences that Fountain met its 2015 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 Fountain's compliance report and NC-RETS sub-account indicate that Fountain met its REPS requirements for 2015. Additionally, the Public Staff states that although Fountain's incremental costs of REPS compliance remained below the cost cap for 2015, Fountain may have difficulty in staying below the cost cap in future years due to its small number of customers (299). The Public Staff notes that Fountain's administrative costs for REPS were roughly 71 percent of its total REPS costs, and that other small municipalities have been able to reduce their REPS compliance costs by contracting for compliance services with larger electric power suppliers. The Public Staff recommends this course of action for Fountain.

Based upon the foregoing and the record in this proceeding, including Fountain's 2015 REPS compliance report, the data in Fountain's 2015 compliance sub-account in NC-RETS, and the comments of the Public Staff, the Commission concludes that Fountain complied with its 2015 REPS requirements and therefore, the RECs and EECs in Fountain's 2015 compliance sub-account in NC-RETS should be retired. The Commission further concludes that Fountain's

2015 compliance report includes the information and supporting documentation required by Commission Rule R8-67(c), and therefore, Fountain's 2015 compliance report should be approved. Finally, the Commission agrees with the Public Staff's recommendation that Fountain should consider contracting for compliance services with a larger electric supplier as an option for Fountain to continue to meet its REPS requirements while maintaining incremental costs of compliance below the annual cost cap. Therefore, the Commission directs Fountain to address this matter in its 2017 REPS filings.

GreenCo

On September 1, 2016, GreenCo filed its 2015 REPS compliance report. GreenCo's compliance report indicates that the combined 2014 total retail sales of GreenCo members and REPS compliance participants were 12,991,053 MWh. Therefore, GreenCo's 2015 REPS obligation, based on six percent of 2014 total retail sales, is 779,464 RECs; its 2015 solar set-aside requirement, based on 0.14 percent of 2014 total retail sales, is 18,188 solar RECs; and GreenCo's share of the aggregate poultry waste set-aside requirement is 16,587 poultry waste RECs. GreenCo's 2015 compliance sub-account in NC-RETS evidences that GreenCo met its 2015 REPS compliance 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 GreenCo's report and NC-RETS sub-account indicate that GreenCo met its REPS requirements for 2015. The Public Staff notes that GreenCo members earn EECs from the following EE programs: Agricultural EE, Commercial EE, Commercial New Construction, Community Efficiency (low income), EnergyStar Appliances, EnergyStar New Home Construction, EnergyStar Lighting, Energy Cost Monitor, Refrigerator/Freezer Replacement, and Water Heating Efficiency. GreenCo bases the energy savings for these programs on data and analyses from GDS's 2012 market potential study. The Public Staff further notes that GreenCo's administrative costs, as a percentage of its incremental REPS compliance costs, is much higher than most of the other EMC and municipal electric power suppliers. The Public Staff recommends that the Commission approve GreenCo's 2015 report, including the M&V results for the EECs it earned for 2015 REPS compliance.

Based on the foregoing and the record in this proceeding, including GreenCo's 2015 REPS compliance report, the data in NC-RETS, and the Public Staff's comments, the Commission concludes that GreenCo's member EMCs, along with Mecklenburg EC, Broad River EC, and Oak City, met their 2015 REPS requirements and therefore, the RECs and EECs in GreenCo's 2015 compliance sub-account in NC-RETS should be retired. The Commission further concludes that GreenCo's 2015 compliance report includes the information and supporting documentation required by Commission Rule R8-67(c), and therefore, GreenCo's 2015 compliance report should be approved. Finally, the Commission concludes that it is appropriate for GreenCo to address its disproportionately high administrative costs. Therefore, the Commission will require GreenCo to include such an explanation in its 2016 compliance report and/or 2017 compliance plan, and the Commission requests that the Public Staff provide comments on this issue in that proceeding.

NCEMPA

On August 31, 2016, NCEMPA filed its 2015 REPS compliance report. NCEMPA's compliance report states that NCEMPA's total 2014 retail sales were 7,118,072 MWh. Based on six percent of its 2014 retail sales, NCEMPA's 2015 REPS obligation is 427,085 RECs, and based on 0.14 percent of NCEMPA's total 2014 retail sales, its solar set-aside obligation is 9,966 solar RECs. NCEMPA's share of the poultry waste set-aside requirement is 9,088 poultry waste RECs. Consistent with these requirements, the data in NC-RETs evidences that NCEMPA submitted the required number of RECs for retirement based upon the foregoing sales levels and REPS requirements, including the use of SB 886 RECs.[1]

In its comments, the Public Staff states that NCEMPA's compliance report and NC-RETS compliance sub-account indicate that NCEMPA met its REPS requirements for 2015. The Public Staff recommends that the Commission approve NCEMPA's 2015 report.

Based upon the foregoing and the record in this proceeding, including NCEMPA's 2015 compliance report, the data in NC-RETS, and the Public Staff's comments, the Commission concludes that the NCEMPA municipalities met their 2015 REPS obligations, and therefore, the RECs and EECs in NCEMPA's 2015 compliance sub-account in NC-RETS should be retired. The Commission further concludes that NCEMPA's 2015 compliance report includes the information and supporting documentation required by Commission Rule R8-67(c), and therefore, NCEMPA's 2015 compliance report should be approved.

NCEMPA1

On August 31, 2016, NCEMPA1 filed its 2015 REPS compliance report. NCEMPA1's compliance report states that NCEMPA1's total 2014 retail sales were 4,966,126 MWh. Based upon the six percent requirement, NCEMPA1's 2015 REPS obligation is 297,968 RECs. Based upon the 2015 solar set-aside requirement of 0.14 percent, NCEMPA1's solar set-aside obligation is 6,953 solar RECs. NCEMPA1's share of the poultry waste set-aside requirements is 6,341 poultry waste RECs. Consistent with these requirements, the data in NC-RETS evidences that NCEMPA1 met its 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 NCEMPA1's compliance report and NC-RETS compliance sub-account indicate that NCEMPA1 met its REPS requirements for 2015. The Public Staff recommends that the Commission approve NCEMPA1's 2015 compliance report.

Based upon the foregoing and the record in this proceeding, including NCEMPA1's 2015 compliance report, the data in NC-RETS, and the Public Staff's comments, the Commission concludes that the NCEMPA1 municipalities met their 2015 REPS obligations, and therefore, the RECs and EECs in NCEMPA1's 2015 compliance sub-account in NC-RETS should be retired. The Commission further concludes that NCEMPA1's 2015 compliance report includes the

[1] SB 886 RECs are those available under S.L. 2011-279 (Senate Bill 886). These RECs are assigned triple credit, with each SB 886 REC being assigned credit for two poultry waste RECs and one REC eligible to meet the general REPS requirements.

information and supporting documentation required by Commission Rule R8-67(c), and therefore, NCEMPA1's 2015 compliance report should be approved.

TVA

On September 1, 2016, TVA filed its 2015 REPS compliance report. TVA's compliance report indicates that its total 2014 retail sales were 604,268 MWh. Based upon the six percent requirement, TVA's 2015 REPS requirement is 36,256 RECs. Based on the solar set-aside requirement of 0.14 percent, TVA's 2015 solar set-aside requirement is 846 solar RECs. TVA's share of the 2015 aggregate poultry waste set-aside requirement is 729 poultry waste RECs. The data in TVA's 2015 compliance sub-account in NC-RETS evidences that TVA met its REPS requirements for 2015 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 2015 compliance report and NC-RETS compliance sub-account indicate that TVA met the requirements for general RECs and solar RECs for 2015. The Public Staff discusses an error with NC-RETS that initially created an inconsistency between TVA's filed report and its NC-RETS sub-account pertaining to the compliance year's sales. This error caused incorrect REC requirements for all REPS components of TVA's compliance year. However, the Public Staff further states that the NC-RETS coordinator, in cooperation with TVA, corrected the error in NC-RETS, and the number of RECs TVA submitted for retirement in NC-RETS is now correct for TVA's actual 2014 sales. Finally, the Public Staff notes that TVA did not use any EECs for REPS compliance in 2015, 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 2015 compliance report.

Based upon the foregoing and the record in this proceeding, including TVA's 2015 REPS compliance report, the data in NC-RETS, and the Public Staff's comments, the Commission concludes that TVA's electric distributors complied with their 2015 REPS requirements, and therefore, the RECs and EECs in TVA's 2015 compliance sub-account in NC-RETS should be retired. The Commission further concludes that TVA's 2015 compliance report includes the information and supporting documentation required by Commission Rule R8-67(c), and therefore, TVA's 2015 compliance report should be approved.

2016 REPS COMPLIANCE PLANS

Each EMC and municipal electric power supplier (or its REPS compliance aggregator) filed in this docket the 2016 REPS compliance plan required by Commission Rule R8-67(b).[1] In its comments, the Public Staff states that the 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 2016, 2017, and 2018 (the relevant planning period for the 2016 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 G.S. 62-133.8(h)(3)

[1] The Commission addresses Halifax EMC's 2016 compliance plan by separate order issued contemporaneous with this order.

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 2016 compliance plan filed by each EMC or municipal electric power supplier (or its compliance aggregator) and the comments of the Public Staff.

Based upon the foregoing and the record in this proceeding, including the 2016 REPS compliance plans filed by each EMC and municipal electric service provider (or its REPS compliance aggregator) and the comments on the plans filed by the Public Staff, the Commission concludes that each EMC and municipal electric service provider 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 2015 REPS compliance requirements and filed 2015 compliance reports and 2016 compliance plans that meet the requirements of Commission Rule R8-67. Further, the Commission concludes that the incremental costs incurred by each of these EMC and municipal electric service providers to satisfy the 2015 REPS requirements are below the total annual spending limit applicable to each electric power supplier as established in G.S. 62-133.8(h)(3) and (4). As noted in this order, these conclusions do not encompass Halifax's REPS filings, which are addressed by separate order issued contemporaneous with this order in this proceeding. Finally, the Commission concludes that these electric power suppliers have demonstrated sufficient planning to meet their future REPS obligations, including, individually and collectively making reasonable efforts to achieve compliance with the swine and poultry waste set-aside requirements.

IT IS, THEREFORE, ORDERED, as follows:

1. That EnergyUnited, Fayetteville PWC, Fountain, GreenCo, NCEMPA, NCEMPA1, and TVA met their 2015 REPS obligations or those obligations on behalf of the electric power suppliers that they serve, and that the RECs and EECs in the 2015 compliance sub-accounts in NC-RETS of each of these electric power suppliers or REPS compliance aggregators shall be, and hereby are, retired;

2. That EnergyUnited, Fayetteville PWC, Fountain, GreenCo, NCEMPA, NCEMPA1, and TVA filed 2015 REPS compliance reports that meet the requirements of Commission Rule R8-67, and that these 2015 REPS compliance reports shall be, and hereby are, approved;

3. That EnergyUnited, Fayetteville PWC, Fountain, GreenCo, NCEMPA, NCEMPA1, TVA, and Waynesville filed 2016 REPS compliance plans that meet the requirements of Commission Rule R8-67, and that these 2016 REPS compliance plans shall be, and hereby are, accepted; and

4. That the Chief Clerk shall send a copy of this Order to Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Virginia Electric Power Corporation, d/b/a, Dominion North Carolina Power.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of June, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. E-100, SUB 150

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Implement	)	ORDER ADOPTING AND
G.S. 62-110.8	)	AMENDING RULES

BY THE COMMISSION: On July 28, 2017, the Commission issued an order initiating this rulemaking proceeding to adopt and modify the Commission's rules, as necessary, to implement G.S. 62-110.8, enacted S.L. 2017-192, which requires Duke Energy Progress, LLC (DEP), and Duke Energy Carolinas, LLC (DEC) (together, Duke) to file with the Commission a program for the competitive procurement of energy and capacity from renewable energy facilities with the purpose of adding renewable energy to the State's generation portfolio in a manner that allows the State's electric public utilities to reliably and cost-effectively serve customers' future energy needs (Competitive Procurement of Renewable Energy or CPRE Program). G.S. 62-110.8(a). To facilitate the Commission adopting final rules in this proceeding in advance of the mandated utilities' filings, that order set an expedited schedule for filings in this proceeding. In addition, that order made DEP and DEC (together, Duke), parties to this proceeding and recognized the participation of the Public Staff. Consistent with G.S. 62-110.8(h), that Order required the parties' initial and reply filings to specifically address the following:

(1) Oversight of the competitive procurement program.

(2) To provide for a waiver of regulatory conditions or code of conduct requirements that would unreasonably restrict a public utility or its affiliates from participating in the competitive procurement process, unless the Commission finds that such a waiver would not hold the public utility's customers harmless.

(3) Establishment of a procedure for expedited review and approval of certificates of public convenience and necessity (CPCN), or the transfer thereof, for renewable energy facilities owned by the public utility and procured pursuant to this section. The Commission shall issue an order not later than 30 days after a petition for a certificate is filed by the public utility.

(4) Establishment of a methodology to allow an electric public utility to recover its costs pursuant to G.S. 62-110.8(g).

(5) Establishment of a procedure for the Commission to modify or delay implementation of the provisions of this section in whole or in part if the Commission determines that it is in the public interest to do so.

On or after August 11, 2017, the Commission issued orders allowing the following to intervene in this proceeding: North Carolina Sustainable Energy Association (NCSEA), Carolina Utility Customers Association, Inc. (CUCA), Carolina Industrial Group for Fair Utility Rates II and III (collectively, CIGFUR), North Carolina Clean Energy Business Alliance (NCCEBA), North Carolina Electric Membership Corporation (NCEMC), North Carolina Pork Council (NCPC), Virginia Electric and Power Company, d/b/a, Dominion Energy North Carolina (Dominion), and SunEnergy1, LLC (SunEnergy1).

On August 16, 2017, Duke, NCSEA, NCCEBA, and the Public Staff filed initial comments and/or proposed rules. On the same day, the Southern Environmental Law Center (SELC), Kevin Edwards, and Jim Price filed consumer statements of position.

By orders issued in this docket on August 24, 2017, and August 30, 2017, the Commission extended the August 25, 2017 deadline for filing of reply comments and revisions to the proposed rules to September 8, 2017. On September 8, 2017, Duke filed reply comments and an amended proposed rule, NCCEBA and NCSEA jointly filed reply comments and an amended proposed rule, and SunEnergy1 filed comments. In addition, the Public Staff filed a letter stating that it had participated in discussions with other parties regarding their initial comments and proposed rules, reviewed a draft of the proposed rule that Duke intended to file on September 8, and that the Public Staff generally agrees with Duke's revised rule, as drafted. However, the Public Staff further stated that it wishes to continue discussions with Duke and the other parties regarding the consideration of pricing or cost information included in a utility self-build proposal, as well as the treatment of selected projects at the expiration of the initial contract term or the expiration of the term of the market-based cost recovery mechanism.

On September 13, 2017, the Commission issued an Order Allowing Additional Reply Comments and Modifying Procedural Schedule. In that Order, the Commission noted that, based upon a preliminary review of the filings in this proceeding, the issues in controversy are limited but of a tenor that makes compromise challenging. Therefore, that Order allowed the parties an additional opportunity to file reply comments focusing on the issues in controversy and supporting proposed changes with legal and/or policy justifications by filing additional reply comments on or before September 22, 2017.

On September 22, 2017, Duke, NCCEBA and NCSEA, NCEMC, and the Public Staff filed additional reply comments.

No other parties filed comments or proposed rules, and the parties reached agreement on many of the provisions in their proposed rules.

The Commission has carefully weighed all of the comments filed in this docket. On the basis thereof, the Commission adopts a new Commission Rule R8-71 and amends related

Commission rules as reflected in the attached Appendix A. In this order, the Commission summarizes the comments filed, identifies and discusses the key provisions of the parties' proposed rules and the major disagreements among the parties, and discusses the Commission's conclusions to resolve these disagreements. In adopting these rules, the Commission has endeavored to give full effect to the intent of the General Assembly as expressed in the enactment of G.S. 62-110.8.

COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY

Subsection 62-110.8(a) establishes the CPRE Program, requiring the Duke utilities to develop and file for Commission approval a program for issuing requests for proposals to procure sufficient energy and capacity from eligible renewable energy facilities in the aggregate amount of 2,660 MW over a 45-month period. Subject to G.S. 62-110.8(b)(1-4), the Duke utilities are granted flexibility to implement the CPRE Program, either jointly or individually, by any of three methods: (1) acquiring renewable energy facilities from third parties and subsequently owning and operating these facilities, (2) constructing, owning, and operating renewable energy facilities, up to 30% of the utility's requirement, and (3) purchasing energy, capacity, and environmental and renewable attributes from third-party facility owners that allow the utility to dispatch, operate, and control the facilities to the same extent as the utility's own generating facilities. Further, the Duke utilities are granted the authority to determine the location and allocated amount of energy and capacity procured within their respective balancing authority areas, whether located within or outside North Carolina, in light of the policy considerations detailed in G.S. 62-110.8(c). Finally, the Duke utilities are authorized to recover the costs of the CPRE Program through an annual rider pursuant to G.S. 62-110.8(g).

Subsection G.S. 62-110.8(b) limits the Duke utilities' requirements and authority under the CPRE Program. First, the required 2,660 MW in renewable energy-fueled generating capacity may be adjusted if, prior to the end of 45-month initial procurement period, the Duke utilities have executed power purchase agreements and interconnection agreements with renewable energy facilities representing 3,500 MW in aggregate generation capacity that is not subject to utility dispatch or curtailment and was not procured pursuant to G.S. 62-159.2 (establishing a program for "direct renewable energy procurement for major military installations, public universities, and other large customers"). G.S. 62-110.8(b)(1). Second, the Duke utilities' procurement obligation is limited to those purchases which they can make below their respective forecasted avoided cost calculated over the term of the power purchase agreement. G.S. 62-110.8(b)(2). Third, the Duke utilities are required to submit pro forma contracts to the Commission that define limits and compensation for resource dispatch and curtailments and provide for a 20-year term (unless the Commission determines a different term is in the public interest). G.S. 62-110.8(b)(3). Fourth, the Duke utilities' option to self-build renewable energy facilities under the CPRE program is limited to 30% of the utility's required procurement obligation. G.S. 62-110.8(b)(4). In addition, to ensure equitable treatment in the procurement process, the CPRE Program is to be independently administered by a third-party entity to be approved by the Commission. G.S. 62-110.8(d). While the Duke utilities are expressly permitted to participate in a competitive procurement process, the utilities are limited to participating within their own assigned service territory, and limited in the ability to use nonpublic information in the process. Finally, pursuant to G.S. 62-110.8(g), the Duke utilities are authorized to recover certain costs of the CPRE Program, subject to the provisions of that section, including a limitation on the annual increase of 1% of the utility's total North Carolina retail jurisdictional gross revenues for the preceding calendar year.

The Commission is assigned an oversight role in the CPRE Program. This role includes adopting the rules that are the subject of this order, approving the Duke utilities' proposed CPRE Program(s), adjusting the total required amount of procurement, requiring a new competitive procurement at the end of the initial 45-month CPRE Program based on a showing of need in a utility's most recent biennial integrated resource plan, approving the pro forma contracts filed by the Duke utilities, approving the third-party entity to independently administer the program, and approving the annual rider for utility cost recovery. The foregoing, as enacted in G.S. 62-110.8, guides the Commission's consideration of the proposed rules and the comments filed in this docket.

SUMMARY OF THE PARTIES' COMMENTS AND PROPOSED RULES

The Commission recognizes and appreciates the effort that the parties undertook to reach consensus on proposed rules. This effort has produced two versions of proposed rules: those filed by Duke, which are generally supported by the Public Staff, and those filed by NCSEA and NCCEBA. The two versions are similar in layout and conform to the general format of the Commission's rules, and the Commission adopts the layout as proposed by the parties. In addition, in recognition that the definitions section of the proposed rule is largely undisputed and for convenience in addressing the disputed issues, the Commission uses these defined terms in this order.

Consistent with the Commission's Order initiating this rulemaking proceeding, the parties' comments were organized around the five specific directives in G.S. 62-110.8(h). The Commission considered all the parties' comments on each of these directives and summarizes the same in the remainder of this section.

Commission Oversight of CPRE Program

By its comments and proposed rule, Duke argues that the Commission's oversight of the CPRE Program should be implemented similarly to the Commission's implementation of the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) through Commission Rule R8-67. Therefore, Duke's proposed rule requires DEC and DEP to annually file CPRE Program plans, compliance reports, and applications for cost recovery, similar to the requirements of Commission Rule R8-67(b) and (c) (requiring the annual filing of a REPS compliance plan, and REPS compliance report, respectively). Duke argues that this approach is appropriate based upon the CPRE Program framework, which Duke describes as imposing prescriptive requirements as to the amount of renewable resource capacity, but also providing broad flexibility for Duke to develop the program. In support of its argument, Duke states that these annual filings will allow the Duke utilities to refine their individual or aggregate procurement strategies each year during the 45-month procurement period and to provide updated information to the Commission, Public Staff, and market participants. In addition, Duke states that this approach will allow the Commission to monitor overall progress toward meeting the Duke utilities' procurement obligations and the limits on the program. Further, Duke states that the annual compliance report and cost recovery application required in its proposed rule (discussed below) would allow the Commission to oversee Duke's implementation of the CPRE Program and the costs incurred to do so. Finally, Duke states that the compliance report required by its proposed rule would allow the Commission to assure the requirements of the CPRE Program are being met within the limitations provided in G.S. 62-110.8, including the cost-effectiveness limitation and the independent administration by a third-party entity designed to ensure that all bids are treated equitably.

By its initial comments, NCSEA argues that the legislature was interested in creating an equitable and transparent process for all parties involved, both independent power producers and utilities. These "overarching principles," NCSEA argues, should guide the Commission's consideration of the following: (1) the role of the independent administrator, (2) transparency of data, (3) dispute resolution, (4) placing independent power producers and utilities on a "level playing field," (5) several issues that NCSEA argues require clarification, and (6) the content and timing of the utilities' filings. Finally, NCSEA argues that several issues do not require the Commission to adopt rules, but nonetheless necessitate Commission oversight, action, and approval. NCSEA identifies these issues as: (1) bidder qualification requirements, (2) requirements for responses to competitive procurements, and (3) the pro forma power purchase agreement. NCSEA proposes that these issues be addressed through a stakeholder process with a final report to and consideration by the Commission.

By its initial comments, NCCEBA encouraged the Commission to establish a published schedule for competitive procurements, including target dates for each solicitation window and the volume sought for each solicitation. NCCEBA further argues that the Commission's rules should address how and when the Duke utilities will publicize information about the location of desired renewable energy facilities solicited through an RFP and how interconnection costs will be determined. NCCEBA also argues that the independent administrator is key to providing a fair and equitable evaluation of bids received and that the Commission should consider criteria that ensure the administrator is truly independent, in particular, when a utility is participating in the solicitation as a bidder. Finally, NCCEBA argued that the Commission and the Independent Administrator should ensure that all bidding is based upon a clearly communicated common metric, with equal access to the cost limitation information, and that the Commission should establish reasonable thresholds that must be met to demonstrate project viability, including site control, an interconnection agreement application, a CPCN application, security and assurances, and bidder qualifications.

By its initial comments, SunEnergy1 addresses several aspects of the Commission's oversight of the CPRE Program. First, SunEnergy1 argues that the Commission should establish and publish a schedule, with targeted dates and anticipated volumes for each solicitation window, over the 45-month initial procurement period. SunEnergy1 states that this would allow interested entities to plan their responses and proposed projects in advance and would be consistent with the goal of transparency and fair competition outline elsewhere in G.S. 62-110.8. Second, SunEnergy1 argues that it is essential that any competitive procurement policy be based on equality of opportunity between developers and between developers and Affiliate(s). SunEnergy1 emphasizes that the 30% limitation on utility-owned renewable energy facilities in G.S. 62-110.8(b)(4) is a ceiling and not a floor; thus, 100% of the Duke utilities' procurement requirement should be open to competition from developers not affiliated with the utilities and proposals, whether from these "independent developers" or Affiliates should be assessed based on the same criteria. In addition, SunEnergy1 comments that the independent administrator, with review and approval of the Commission, should establish and publish in advance criteria that will be applied to all proposals and the weight to be assigned to each criteria. Third, SunEnergy1 argues that that the rules implementing the CPRE Program should include requirements that electric public utilities provide all information necessary for the preparation of competitive bids, including, potentially, non-public information and information about the utility's determined location and allocation of the amount of the competitive procurement. SunEnergy1 cites G.S. 62-110.8(c) and (e) in support of this argument and concludes that the Commission should require this information to be made available to all potential bidders as soon as reasonably possible in the bidding process. Fourth, SunEnergy1 argues that the Commission should establish minimum thresholds that each bid and each potential provider must meet in order to take part in the process. SunEnergy1 suggests that this criteria include demonstrating that the bidder has site control, experience in the field, and the ability to complete projects and render them operational. In addition, SunEnergy1 suggests that the Commission should require that all bidders have submitted applications for an Interconnection Agreement and a CPCN, and that "shortlisted bidders" post reasonable security, such as a posted bond or deposit and a letter of credit.

By its initial comments, and as it recommended in past avoided cost proceedings, the Public Staff reiterated its support for market-based approaches to determine the most cost-effective options for utilities to meet their customers' needs, provided that the competitive bidding process is appropriately structured and an independent administrator is utilized. The Public Staff encourages the Commission to use a competitive bidding process that incorporates the following "best practices": (1) the procurement process should be transparent, fair, and objective, (2) the procurement should be designed to encourage robust competitive offerings and creative proposals from market participants, (3) the procurement should select winning offers based on appropriate evaluation of all relevant price and non-price factors, (4) the procurement should be conducted in an efficient and timely manner, and (5) when using a competitive procurement process, regulators should align their own procedures and actions to support the development of a competitive response.[1] The Public Staff notes that competitive bidding options have been available in North Carolina since the late 1980s, but has not been utilized on a regular basis for purchases from qualifying facilities. The Public Staff further notes that those RFPs did not involve Commission approval or an independent administrator, and, in this proceeding, the General Assembly has left significant discretion to Duke regarding the CPRE Program. In addition to the NARUC "best practices," the Public Staff recommends that the Commission consider renewable energy competitive procurement processes implemented in other southeastern states, in particular, that process implemented by Georgia Power.[2] Finally, the Public Staff recommends that the Commission periodically review the contract with the independent administrator selected by the Commission to oversee the competitive procurement.

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[1] See Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices, prepared by the Analysis Group for National Association of Regulatory Utility Commissioners (NARUC), July 2008. Online at: http://pubs.naruc.org/pub/4AE5DC97-2354-D714-5151-A46473B286E7.

[2] See Ga. Comp. R. & Regs. 515-3-4-.04 (2011).

By their reply comments, additional reply comments, proposed rules and revised proposed rules, the parties reached agreement on many of the issues related to Commission oversight of the CPRE Program. In comparing the two competing versions of the proposed rules, the Commission identifies the following issues for decision:

1. Issues related to the initial CPRE Program filings and guidelines (proposed Rule R8-71(c)(1)):

   Should the rule expressly provide for an opportunity for interested parties to comment on the CPRE Program guideline?

   Should the rule require pro forma contracts to be filed as a part of the CPRE Program guidelines?

2. Issues related to the selection and role of the Independent Administrator (proposed Rule R8-71(d)):

   Should the Independent Administrator be retained by the Duke utilities or by the Commission?

   Should the CPRE Program Methodology used to evaluate proposals be published 30 or 60 days prior to the initial CPRE RFP Solicitation?

   Should the Independent Administrator be allowed to interact with Duke utility personnel who are involved in evaluating proposals, and if allowed, how should this interaction take place and what is the appropriate timing of these interactions?

   Should the rule address the handling of non-publicly available information about the Duke utilities' transmission or distribution system used in developing proposals, and, if so, what is the appropriate method for publishing this information to CPRE Program participants?

   Should the rule require the Independent Administrator to work "in coordination with" the Duke utilities' personnel who are involved in evaluating proposals?

3. Issues related to the CPRE RFP Solicitation Structure and Process (proposed Rule R8-71(f)):

   Should the Duke utilities be required to prepare evaluation factors as part of their initial draft of the CPRE RFP?

   Should the proposal selection process include an opportunity to refresh proposals, allowing market participants to make a "final best offer"?

   What is the appropriate process for resolving discrepancies between the Independent Administrator's proposal selections and those of the Duke utilities?

   Should the Duke utilities be informed of the content of communications between the Independent Administrator and a market participant?

4. Issues related to the CPRE Program Plan and CPRE Compliance Report, and to the Commission's review thereof (proposed Rule R8-71(g), (h), and (i)): Should the rule set November 27, 2017, as the date by which the Duke utilities must file their CPRE Program Plan(s)?

5. Issues related to the CPRE Program Power Purchase Agreements (proposed Rule R8-71(l)):

   Should the Independent Administrator be required to post pro forma contracts to its website 30 or 60 days prior to a solicitation?

   If the Duke utilities' initial proposal(s) include assumptions about pricing after the initial term, should the Duke utilities be required to make these assumptions available to the Independent Administrator and to market participants?

Provision of Waiver of Regulatory Conditions or Code of Conduct Requirements

By its initial comments and proposed rule, Duke argues that provisions enacted in S.L. 2017-192 are aimed at allowing a utility's affiliate companies to participate in the CPRE Program on virtually equal terms with non-affiliated third party developers of renewable energy facilities by easing certain procedural hurdles that apply to transactions between an electric public utility and its affiliates. In support of its argument, Duke cites to the amendment to G.S. 62-153(b), exempting power purchase agreements entered into pursuant to the CPRE Program from the filing and approval requirements of that subsection, and to the enactment of G.S. 62-110(h)(2), requiring the Commission to adopt rules that provide for a waiver of regulatory conditions or code of conduct requirements that would unreasonably restrict an electric public utility or its affiliates from participating in the CPRE Program, unless the Commission finds that such a waiver would not hold the utility's customer's harmless. Initially, Duke argued that the rules adopted in this proceeding should prospectively waive certain regulatory conditions or code of conduct requirements, subject to an objection by an interested person and the Commission's consideration of whether the wavier would hold the utility's customers harmless. However, in response to comments filed by the Public Staff and NCCEBA, Duke abandoned this procedure in favor of one where the utility, at the time it files its proposed CPRE Program guidelines, also identifies any regulatory conditions or code of conduct provisions that the utility seeks to have waived pursuant to G.S. 62-110.8(h)(2). In addition, Duke's amended proposed rule would require filing of power purchase agreements entered into pursuant to the CPRE Program within 30 days of execution.

By their initial comments, NCCEBA and NCSEA argued that Duke's initial proposal was unnecessarily broad and weakened the protections that regulatory conditions and code of conduct requirements are designed to provide. By their filing of reply comments and a revised proposed rule, NCCEBA and NCSEA agree with Duke that the utilities should identify any regulatory conditions and/or code of conduct provisions in their proposed CPRE Program guidelines. However, NCCEBA and NCSEA propose further details that they believe should be required when a utility seeks such a waiver.

By its initial comments, the Public Staff states that it is not aware of any rulemaking requirements associated with waivers from the Regulatory Conditions or Code of Conduct that are needed at this time. Further, the Public Staff observes that Section 2.3 of the Regulatory Conditions and Section II of the Code of Conduct already provide procedures for utilities and their affiliates to seek a waiver from regulatory conditions or code of conduct requirements. The Public Staff cites to G.S. 62-110.8(c) and (e) as indicating the General Assembly acknowledged the critical nature of the information necessary to participate in the CPRE Program and sought to ensure that it will be made available to CPRE Program market participants. In conclusion, the Public Staff states that it expects utilities and their affiliates to fully comply with these requirements and to seek waivers, if needed, in a timely fashion.

By their reply comments, additional reply comments, proposed rules, and revised proposed rules, the parties reached agreement on many of the issues related to requests for waiver of regulatory conditions and/or code of conduct provisions. In comparing the two competing versions of the proposed rules, the Commission identifies the sole remaining disputed issue related to this rule provision as the extent to which Rule R8-71(c)(2) should address the detailed requirements of a utility's filing requesting a waiver.

Expedited Review of CPCN Applications and Requests to Transfer a CPCN

By its comments and proposed rule, Duke argues that its proposed rule establishes both filing requirements and procedures for reviewing applications for, and requests for transfer of, CPCNs that are generally consistent with the existing procedures for review of a CPCN application filed by a small power producer. See G.S. 62-82(a), 62-110.1 and Rule R8-64. Thus, Duke's proposed subsection (k) requires that these filings meet the requirements of G.S. 62-82(a) and 62-110.1, but otherwise provides that these filings are exempt from Rule R8-61. Duke proposes that the application include the same type of exhibits required by Rule R8-64 and a similar procedure for Commission review.

By its initial comments, the Public Staff cites to two instances where the General Assembly has directed the Commission to consider an application for a CPCN on an expedited basis.[1] The Public Staff suggests that these cases may provide useful context for the Commission because, rather than adopting rules for these proceedings, the Commission addressed the procedure on these applications by orders requesting the Public Staff to investigate and present its findings at a regular Staff Conference. The Public Staff further suggests that the Commission could take a similar approach to this expedited process. However, the Public Staff states that it is critical that the application be complete and include all necessary information to allow the Public Staff to evaluate it, and that the Commission would likely need to issue an order promptly scheduling a public hearing, if needed, to meet the 30-day timeframe as required by G.S. 62-110.8(g)(3). Finally, the Public Staff states that, as to the siting of a transmission line required to interconnect a facility that is the subject of this expedited CPCN review procedure, the waiver provisions of

[1] See S.L. 2009-390 (authorizing expedited review of a CPCN application for natural gas generating facilities at retiring coal-fired generating facilities that meet certain requirements, and requiring Commission decision within 45 days); S.L. 2015-110 (providing for a 45-day decision process for a natural gas generating facility that meets certain requirements). See also Docket No. E-2, Sub 960 (CPCN issued pursuant to S.L. 2009-390 for DEP's Wayne County Natural Gas Combined Cycle facility); E-2, Sub 1089 (CPCN issued pursuant to S.L. 2015-110 for DEP's Asheville combined cycle facility).

G.S. 62-101(d)(1) would be a straightforward approach to allow the project to proceed in an expedited fashion.

By their comments, NCCEBA and NCSEA argue that the expedited CPCN review process required by G.S. 62-110.8(g)(3) should treat utilities' CPCN applications and independent power producers' CPCN applications equitably. They state that, under current law, the process for a utility to obtain a CPCN is more burdensome than for an independent power producer. They argue that this expedited review procedure was intended to create a more equitable situation. They further argue that Duke's proposed rule appears to take the provisions of this procedure too far by making the process for review of an independent power producer's CPCN application more burdensome than that for review of a utility's CPCN application. Therefore, their proposed rule use the same process for review of both a utility's and an independent power producer's application for CPCN, or transfer thereof, pursuant to the CPRE Program.

By its initial comments, SunEnergy1, similar to NCCEBA and NCSEA, requests that any process adopted for CPCN review and approval for utility-owned or acquired facilities be consistent with that for non-utility owned facilities. Thus, SunEnergy1 suggests that to the extent the process is streamlined or expedited for public utilities and their affiliates, other market participants should benefit from the same revisions.

By their reply comments, additional reply comments, proposed rules, and revised proposed rules, the parties reached agreement on the basic framework for expedited review of applications for CPCNs and transfer of CPCNs pursuant to the CPRE Program. For reasons explained below, however, the Commission will reject both versions of the proposed rule because they fail to adequately implement the direction from the General Assembly enacted in G.S. 62-110.8(h)(3).

CPRE Program Cost Recovery Mechanism

By its comments and proposed rule, Duke argues that its proposed subsection (j) presents the mechanism for DEC and DEP 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 pursuant to the CPRE Program, as provided in G.S. 62-110.8(g). In support of its argument, Duke states that the proposed cost recovery mechanism is generally modeled on the REPS cost recovery rider, wherein the utility projects costs to be incurred during a future, fixed, 12-month billing period and adjusts these costs through an experience modification factor. See Rule R8-67(e). By its proposed rule, Duke proposes similar procedural requirements as those provided under Rule R8-67(e), including an annual hearing, publication of notice thereof, required supporting information, and aligning test periods with other rider proceedings. Duke further states that 100% of the CPRE Program costs should be recovered through the annual rider authorized by G.S. 62-110.8(g), and not recovered through the fuel factor adjustment in G.S. 62-133.2, the REPS rider in G.S. 62-133.89(h), or through an adjustment to base rates. Duke's comments and proposed rule also addresses the provision in G.S. 62-110.8(g), allowing the authorized revenue for any utility-owned renewable energy facility to be calculated based on a "market price" rather than cost-of-service, provided it is in the public interest to do so. In its proposed (b)(11), Duke proposes a definition of "market price" that would be used in calculating the revenue to be recovered for costs related to utility-owned renewable energy facilities.

NCCEBA initially focused its comments on the portion of the cost recovery mechanism related to calculating the costs recoverable for utility-owned renewable energy facilities. However, by the joint filing of its additional reply comments with NCSEA, NCCEBA and NCSEA do not identify this as an issue in dispute. However, their proposed rule differs slightly from Duke's proposed rule on this issue.

By its additional reply comments, NCEMC focuses on costs associated with the CPRE Program and calls on the Commission to recognize the potential impacts on retail and wholesale customers. NCEMC argues that the CPRE Program was enacted as a reform measure intended to save customers – both wholesale and retail – from unchecked increasing system costs. In particular, NCEMC criticizes a section in Duke's revised proposed rule that contemplates the potential for a separate solar energy-specific avoided cost framework. NCEMC further states that Duke's proposed rule provision would create ambiguity as to whether the inclusion of renewable attributes would result in costs above or below the "traditional or non-solar avoided cost methodology approved by the Commission." NCEMC, therefore, argues that a higher solar avoided cost rate would undermine the reform intended by the General Assembly in enacting S.L. 2017-192. The proposed rule provision that NCEMC focused on in its comments was deleted in later drafts.

By its initial comments, the Public Staff suggests that the Commission's existing rider proceedings provide a good starting framework for defining the cost recovery mechanism for the CPRE Program. The Public Staff argues that any cost recovery mechanism should ensure that costs are allocated to the appropriate riders or to base rates, and that costs associated with any utility- or affiliate-owned facility should be allocated to that project in order to prevent any double counting or to eliminate the potential inclusion of any costs in the rider that are more appropriately allocated to the utility's base rates.

By their reply comments, additional reply comments, proposed rules, and revised proposed rules, the parties reached agreement on many of the issues related to the CPRE Program cost recovery methodology. As discussed below, the parties dispute one aspect of the cost recovery methodology related to recovery of costs or collection of revenue for a utility-owned facility that the utility proposes to recover or collect on a "market basis in lieu of cost-of-service based recovery." See G.S. 62-110.8(g).

Procedure to Modify or Delay CPRE Program Requirements

By its comments and proposed rule, Duke proposed a rule provision that would allow for a utility or interested party to petition the Commission to modify or delay the provisions of G.S. 62-110.8, in whole or in part, if the Commission determines that it is in the public interest to do so. In support of its proposed provision, Duke states that this provision is generally based upon the REPS "off-ramp" provision, see G.S. 62-133.8(i)(2), but does not include the "reasonable efforts" requirement that is included in Rule R8-67(c)(5). Duke explains that difference by noting that the "reasonable efforts" requirement was expressly included in G.S. 62-133.8(i)(2), but not included in G.S. 62-110.8(h)(5). Duke argues that adopting NCSEA and NCCEBA's position would prospectively limit the Commission's authority and discretion.

By its initial comments, NCCEBA argues that modification or delay of the CPRE Program requirements should be allowed only in exceptional circumstances. NCCEBA further argues that its members need predictability and reasonable certainty that the Duke utilities will comply with the CPRE Program requirements on schedule. In considering requests to modify or delay the CPRE Program requirements, NCCEBA argues that the Commission should require the utility to demonstrate that the request is not the result of its own actions or inactions and that it made reasonable efforts to avoid modification or delay. In evaluating whether a modification or delay is in the "public interest," NCCEBA suggests the Commission rely upon the limitations in G.S. 62-110(b)(2) related to cost-effectiveness. Finally, NCCEBA argues that, even if the Commission allows a modification or delay, the Commission should still require the utilities to comply with the CPRE Program's 45-month deadline and 2,660 MW procurement obligation.

By its initial comments, NCSEA argues that the only factor that could lead the Commission to determine that it is in the public interest to modify or delay the requirements of the CPRE Program is the cost-effectiveness limitation in G.S. 62-110.8(b)(2). Similar to NCCEBA, NCSEA argues that even if the Commission allows a modification or delay, the Commission should still require the utilities to comply with the CPRE Program's 45-month deadline and 2,660 MW procurement obligation.

By the proposed rule attached to their joint additional reply comments, NCCEBA and NCSEA argue that an electric public utility should be required to demonstrate that a modification or delay in the CPRE Program requirement is justified based upon clear and convincing evidence that the utility made reasonable efforts to comply. Further, their proposed rule would provide that no delay or modification would be granted during the initial CPRE Program Procurement Period.

By its initial comments, the Public Staff suggests that the REPS "off-ramp" provision would provide a good template for the Commission's rules implementing G.S. 62-110.8(h)(5). In its reply and additional reply comments, the Public Staff expressed general agreement with Duke's proposed rule.

By their reply comments, additional reply comments, proposed rules, and revised proposed rules, the parties reached agreement on many of the issues related to the procedure for delay or modification of the CPRE Program requirements at (i)(2) of the proposed rule. In comparing the two competing versions of the proposed rules, the Commission identifies three issues in dispute: the appropriate burden of persuasion to justify a modification or delay, whether a modification or delay should be allowed during the Initial CPRE Program Procurement Period, and the level of detail required in a petition requesting a delay or modification.

DISCUSSION AND CONCLUSIONS

The Commission has reviewed and carefully considered the parties' comments, proposed rules, and legal and policy arguments supporting their positions. The Commission determines that the undisputed provisions of the proposed rules comport with the legislative intent expressed in G.S. 62-110.8 and are a reasonable means of implementing the provisions of that section.

Therefore, the Commission concludes that these undisputed provisions should be adopted with revisions that tend to streamline the text of the rule and conform to the general format of other Commission rules. Of note, these revisions include the use of the term "proposal" rather than "bid," recognizing that responses to a CPRE RFP Solicitation are evaluated on both economic and noneconomic factors, and changes to the proposed rules to conform to this syntax. In addition, the Commission will refer to the third-party entity tasked with administering the CPRE Program as the "Independent Administrator," consistent with the plain language of G.S. 62-110.8(d).

As for the provisions of the proposed rule that are in controversy, the Commission addresses these provisions, as follows.

Commission Oversight of CPRE Program

1. Issues related to the initial CPRE Program filings and guidelines (Rule R8-71(c)(1)):

The Commission concludes that Rule R8-71(c)(1) should not expressly provide for an opportunity for interested parties to comment on the CPRE Program guidelines; rather, the Commission finds it appropriate to allow such an opportunity through the issuance of a procedural order establishing a schedule for interested persons to file petitions to intervene and comments. While the Commission agrees with NCSEA that an opportunity for interested persons to review and comment on the guidelines is important, the Commission determines that this level of detail is inappropriate for inclusion in the rule. Therefore, the Commission adopts Duke's proposed version of subsection (c)(1), with modifications as discussed immediately below.

The Commission concludes that Rule R8-71(c)(1) should require the Duke utilities to include pro forma contracts to be filed as a part of the CPRE Program guidelines, as proposed by NCCEBA and NCSEA. It appears that there would be little or no additional burden on Duke to include the pro forma contracts in its CPRE Program guidelines because Duke has proposed an informal process for sharing information with the Public Staff and market participants in advance of the filing date, which the Commission understands could include sharing early drafts of the pro forma contracts. To the extent that Duke anticipates a need to revise its pro forma contracts after submission as part of the CPRE Program guidelines, it should alert the Commission, the Public Staff, and market participants to this possibility in its filing of the CPRE Program guidelines. Therefore, the Commission adopts subsection (c)(1)(v) reflecting this conclusion.

2. Issues related to the selection and role of the Independent Administrator (Rule R8-71(d)):

The Commission concludes that the Independent Administrator should be retained by the Duke utilities and not by the Commission. As provided in the plain language of G.S. 62-110.8(d), the Commission will approve the Independent Administrator and the administrative fees to be paid by those participating in the competitive procurement process. Given that the Duke utilities will be collecting these fees and paying the Independent Administrator, the functions that are entailed in retaining the Independent Administrator are appropriately left to the Duke utilities. Although the Duke utilities will be paying and retaining the Independent Administrator, subsection (d)(4) of the rule makes clear that the Independent Administrator remains subject to Commission oversight. This oversight function could include receiving and acting upon a complaint that a Duke utility or the Independent Administrator is carrying out their respective responsibilities in a manner inconsistent with G.S. 62-110.8, the Commission's rules, or a lawful order issued by the Commission. Therefore, the Commission adopts subsection (d)(4) reflecting this conclusion.

The Commission concludes that it is imprudent to adopt in subsection (d)(6) either a 30- or 60-day deadline for publication of the CPRE Program Methodology. Instead, the Commission will require the Independent Administrator to publish the CPRE Program Methodology prior to the initial CPRE RFP Solicitation and, in any event, to do so no later than a date to be set by the Commission order approving the CPRE Program and Program guidelines. Therefore, the Commission adopts a subsection (d)(6) reflecting this conclusion.

The Commission concludes that practical considerations require allowing the Independent Administrator to interact with the Duke utilities' personnel who are involved in evaluating proposals. This interaction should take place within the Evaluation Team and Proposal Team construct as proposed by Duke and agreed to by the Public Staff. The plain language of G.S. 62-110.8(c) expressly provides that the Duke utilities shall have authority to determine the location and allocated amount of the competitive procurement within their respective balancing authority areas taking into consideration three specific considerations. By necessity, the Independent Administrator will need to obtain some information from Duke and incorporate that information into its CPRE Program Methodology. In addition, Duke's proposed rule contemplates additional communication before subsequent CPRE RFP Solicitations, which the Commission concludes tends to foster continued improvement in the process.

The Commission recognizes NCCEBA, NCSEA, and SunEnergy1's concerns that this puts the Duke utilities and their Affiliates on the inside track when participating in a CPRE RFP Solicitation. However, the Commission determines that the segregation of personnel proposed by Duke, and agreed to by the Public Staff, within the Evaluation Team and Proposal Team construct provides a reasonable protection against the Duke utilities and their Affiliates obtaining an unfair advantage. The Commission notes that this construct includes these personnel making an acknowledgement of compliance with the Commission's rules and filing of the same with the Commission. Therefore, the Commission adopts subsections (d)(6) and (d)(8) reflecting these conclusions.

The Commission determines that it is appropriate to address the handling of non-publicly available information about the Duke utilities' transmission or distribution systems used in developing proposals by requiring the Independent Administrator make this information available to persons who have expressed an intent to submit a proposal in response to a CPRE RFP Solicitation. This conclusion is supported by the plain language of G.S. 62-110.8(e). The Commission expects that Duke, the Independent Administrator, and the market participants will develop and implement appropriate protections for this information, such as nondisclosure agreements. Therefore, the Commission adopts subsection (d)(6) reflecting this conclusion.

3. Issues related to the CPRE RFP Solicitation structure and process (Rule R8-71(f)):

The Commission concludes that the Duke utilities should be required to include evaluation factors in the initial draft of the CPRE RFP Solicitation guidelines. The Commission finds merit in beginning the discussions about the evaluation factors and the other matters required to be included in the CPRE RFP Solicitation guidelines and documents earlier rather than later, and requiring the inclusion of the evaluation factors tends to facilitate that discussion. Therefore, the Commission adopts subsection (f)(1)(ii) reflecting this conclusion.

The Commission recognizes the inherent tension in the parties' dispute over proposed subsection (f)(3) (evaluation of responses to CPRE RFP Solicitation) and proposed subsection (f)(4) (selection of CPRE Program Resources). This tension arises, in part, from the legislative direction in G.S. 62-2(3) to promote "adequate, reliable, and economical utility service" to Duke's customers, and the construct of the CPRE Program, allowing Duke and its Affiliates to make proposal(s) in Duke's competitive procurement of energy and capacity from renewable energy facilities, which "shall be independently administered by a third-party entity." G.S. 62-110.8. A proposal process that forces proposals selections on the utility could be viewed as undermining the Commission's ability to look solely to the utility in meeting the directive in G.S. 62-2(3), while a proposal process that grants the utility unilateral authority to select proposals could be viewed as undermining the "independence" of the administration of the CPRE Program. The Commission resolves this tension by adopting Commission Rule R8-71(f)(3).

Under Rule R8-71(f)(3), the evaluation of proposals will occur on a single track, in two steps. In the first step, the Independent Administrator will use the CPRE Program Methodology to evaluate proposals based on the CPRE RFP Solicitation evaluation factors, including economic and noneconomic factors. The Independent Administrator's review will produce a list of proposals that meet the specifications of the CPRE RFP Solicitation, ranked in order from most competitive to least competitive. This ranked list shall be redacted of any information that identifies the market participant that submitted the proposal and any other information that is not reasonably necessary for the utility to complete step two of the evaluation process, including any economic factors such as cost and pricing information. The Independent Administrator will deliver this ranked list of proposals to the utility.

In the second step, the utility shall select the proposals in the ranked order presented by the Independent Administrator until the total generating capacity sought in the CPRE RFP Solicitation is satisfied. The utility may deviate from the ranked order only where the utility determines that the interconnection and operation of a proposed facility, together with a facility or multiple facilities that were the subject of proposals already selected by the utility, would significantly undermine the utility's ability to provide adequate and reliable electric service to its customers. In such a case, the utility may eliminate that proposal from consideration in the CPRE RFP Solicitation. When the utility completes its selection and elimination of proposals, the utility shall notify the Independent Administrator of its selections and eliminations, and include an explanation for the elimination of each proposal. The Independent Administrator shall then provide the utility with the identity of each market participant that submitted a proposal selected by the utility, and the utility shall proceed to execute a contract with each such market participant.

The Commission determines that this evaluation and selection process strikes an appropriate balance between retaining traditional utility authority for the provision of adequate and reliable service and fostering the independence in the CPRE Program that the General Assembly intended. The Commission acknowledges that in adopting this process for evaluation and selection of proposals, the opportunity for refreshed bids by making a best and final offer has been eliminated. The Commission, in its discretion, determines that the better approach is to incentivize market participants to make their best offer in their proposal and to eliminate this additional step in the selection process. In addition, the approach the Commission adopts may shorten the time required to complete the evaluation and selection process, which, in the context of the 45-month CPRE Program Procurement Period, is important to the success of the CPRE Program. Finally, in adopting this evaluation and selection process, the Commission recognizes that opportunities for improvements may arise or become apparent after there is a sufficient historical record of working through the process. Therefore, the Commission will remain open to these opportunities in the future.

Finally, the Commission notes that substantive issues related to restricting communications between market participants and between the Proposal Team(s) and Evaluation Team(s) have been moved from subsection (f) to subsection (e) or deleted. The Commission generally agrees that the deleted restrictions are appropriate, although the level of detail as proposed by the parties is unnecessarily prescriptive for a Commission rule. The Commission expects communication to occur through the Independent Administrator such that the anonymity of market participants is preserved. In addition, the Commission expects the electric public utility to cooperate with the Independent Administrator by providing full access to the personnel and the resources used to develop and evaluate proposals, consistent with the provisions proposed by the parties in this proceeding. These expectations are consistent with the positions Duke takes in advocating for its proposed rule provisions.

4. Issues related to the CPRE Program Plan and CPRE Compliance Report, and to the Commission's review thereof (Rule R8-71(g), (h), and (i)):

The Commission concludes that it is unnecessary to establish, by rule, November 27, 2017, as the date by which the Duke utilities must file their CPRE Program Plan(s). This deadline is established in Section 2(c) of S.L. 2017-192, and Duke has demonstrated its commitment to meet this deadline through its filings in this proceeding. Therefore, the Commission adopts sections (g), (h), and (i) reflecting the deletion of reference to this date.

5. Issues related to the CPRE Program power purchase agreements (Rule R8-71(l)):

For reasons similar to those discussed above, the Commission adopts section (l) reflecting the deletion of the proposed 30- or 60-day publication requirements. As in other contexts of this rule, the Commission intends to address these deadlines in the process of reviewing Duke's CPRE Program guidelines and documents.

The Commission concludes that the Duke utilities should be required to make available to the Independent Administrator and market participants assumptions about pricing after the initial term, if the utilities' initial proposal(s) include such assumptions. This requirement tends to foster transparency in the competitive procurement process and supports the General Assembly's intent to encourage a market-based approach to adding renewable energy resources to the state's generation resources. Therefore, the Commission adopts subsection (l)(4) reflecting this conclusion.

Waiver of Regulatory Conditions and Code of Conduct Provisions

The Commission concludes that it is not necessary to include the prescriptive filing requirement for a request for waiver of regulatory conditions or code of conduct provisions, as proposed by NCSEA. While the Commission generally agrees that this type of information should be included in such a request filed by a utility, the Commission does not find this level of detail appropriate for adoption of filing requirements by rule. Therefore, the Commission adopts subsection (c)(2) as proposed by Duke and agreed to by the Public Staff.

Procedure for Expedited Review and Approval of CPCNs for Renewable Energy Facilities Owned by an Electric Public Utility

In comparing the two competing versions of the proposed rules, the Commission finds both fail to adequately implement G.S. 62-110.8(h)(3). The Commission acknowledges, as the parties have appropriately identified, that there is inherent tension between G.S. 62-110.8(h)(3) and the existing statues and Commission rules that govern the procedure on an application for a CPCN. See G.S. 62-82 and Rules R8-61 and R8-64. This tension arises from the conflict between the plain language of the two statutes: G.S. 62-82 requires publication of notice of a pending application for four consecutive weeks and provides for a hearing upon compliant or upon the Commission's own motion, while G.S. 62-110.8(h)(3) requires the Commission to issue an order within 30 days of an electric public utility filing an application for CPCN or petition to transfer a CPCN pursuant to the CPRE Program. It is apparent, on the face of the statutes, that the Commission cannot meet the 30-day deadline using the G.S. 62-82 procedure.

There being no resolution to this tension in the plain language of the statue, the Commission must resort to statutory interpretation. The cardinal principle of statutory interpretation is to ensure that legislative intent is accomplished. Harris v. Nationwide Mut. Ins. Co., 332 N.C. 184, 191, 420 S.E.2d 124, 128 (1992). When a general statute and a special or particular statute are in conflict, the special or particular statute is controlling; the special statute is viewed as an exception to the provisions of the general statute, since it is presumed that the General Assembly did not intend to create a conflict. Domestic Electric Service, Inc. v. Rocky Mt., 20 N.C. App. 347, 351 (1974). This rule of construction is especially applicable where the specific provision is the later enactment. Food Stores v. Board of Alcoholic Control, 268 N.C. 624, 151 S.E. 2d 582 (1966). While it is true that statutes dealing with the same subject matter must be construed in pari materia and harmonized to give effect to each, Gravel Co. v. Taylor, 269 N.C. 617, 153 S.E. 2d 19 (1967), when the section dealing with the specific matter is clear and understandable on its face, it requires no construction. State ex. rel. Utils. Comm'n. v. Lumbee River Electric Membership Corp., 275 N.C. 250, 260 (1969).

The Commission concludes that the plain language of G.S. 62-110.8(h)(3) is clear and understandable on its face: the General Assembly intended for the Commission to establish an expedited procedure for review of applications for CPCNs, and for the transfer thereof, for renewable energy facilities owned by an electric public utility pursuant to the CPRE Program, wherein the Commission "shall issue an order not later than 30 days after" the electric public utility makes the relevant filing. Subsection 62-110.8(h)(3) being the later enactment, the Commission determines that it is the controlling statute. The Commission concludes that Duke's proposed rule incorporating the 4-week publication requirement of G.S. 62-82 will not effectuate the legislative intent of G.S. 62-110.8(h)(3). Therefore, the Commission declines to adopt Duke's proposed subsection (k).

The Commission also determines that NCCEBA, NCSEA, and SunEnergy1's proposals to include independent power producers in the expedited CPCN review process are inconsistent with the plain language of G.S. 62-110.8(h)(3). The General Assembly could have included in that expedited review process applications filed by these facilities owners, but it chose not to do so. It would be inappropriate for the Commission to expand the scope of this expedited review process beyond what the General Assembly has provided by statute. Therefore, the Commission also declines to adopt NCCEBA and NCSEA's proposed section (k).

Instead, consistent with the Public Staff's comments, the Commission concludes that the proceedings in Docket No. E-2, Subs 960 and 1089 provide the most appropriate model for implementing the expedited CPCN review process required by G.S. 62-110.8(h). Therefore, section (k) incorporates procedures used in both proceedings and modeled on G.S. 62-82(a) and Rules R8-61 and R8-64. The Commission concludes that this combination of procedures best effectuates the legislative intent expressed in G.S. 62-110.8(h). In summary, section (k) provides for processing these applications as follows: filing of preliminary plans and publication of notice of that filing, filing of the application and public notice of that filing, Public Staff investigation and recommendation, and the Commission's consideration of the matter at a Regular Commission Staff Conference approximately three weeks after the application is filed. When no significant complaints are filed with the Commission, these applications should routinely be considered at a Regular Commission Staff Conference within 30 days of the filing of the application. In those cases where significant complaints are filed with the Commission, the Commission will proceed as expeditiously as possible to conduct a public hearing and issue an order on the application. The Commission may issue notices of decision where a final order cannot be issued prior to the 30-day deadline. Petitions to transfer CPCNs would be processed in a similar manner, but foregoing the required filing of preliminary plans. Therefore, the Commission adopts section (k) reflecting this conclusion.

In addition, the Commission adopts a revision to Commission Rule R8-64(a)(1) to clarify that any person, other than an electric public utility, who seeks a CPCN for a facility that will participate in the CPRE Program should make application pursuant to that rule. Finally, the Commission notes that like the deadline in G.S. 62-82, the 30-day deadline in G.S. 62-110.8(h) is properly regarded as "directory" rather than mandatory because the legislature did not express a consequence for failure to comply within the time period. State ex rel. Utils. Comm'n v. Empire Power Co., 112 N.C. App. 265, 276, 435 S.E.2d 553, 558-559 (1993).

Methodology to Allow an Electric Public Utility to Recover CPRE Program Costs

In the two competing versions of subsection (j) of the proposed rule, the parties dispute centers on how to implement the following sentence in G.S. 62-110.8(g):

> Provided it is in the public interest, the authorized revenue for any renewable energy facilities owned by an electric public utility may be calculated on a market basis in lieu of cost-of-service based recovery, using data from the applicable competitive procurement to determine the market price in accordance with the

methodology established by the Commission pursuant to subsection (h) of this section.

The parties' dispute over implementing this sentence is further complicated by their conflicting and confusing proposed definitions of "market price."

In resolving this issue, the Commission looks first to the text of G.S. 62-110.8(g). The Commission concludes that the General Assembly intended subsection (g) to allow a utility to recover costs or collect revenues in excess of its cost of service upon a showing that it is in the public interest to do so. The higher cost or revenue amount allowed is "calculated on a market basis." G.S. 62-110.8(g). Underlying subsection (g) is the assumption that the utility's cost of service will be less than the cost calculated on a market basis. Further, because the CPRE Program limits a utility to procuring energy and capacity from renewable energy facilities that it can procure at a price less than its current forecasted avoided cost, see G.S. 62-110.8(b)(2), it follows that a second assumption underlies subsection (g): that the market-price will be less than the utility's forecasted avoided costs. Thus, the Commission concludes that G.S. 62-110.8(g) is intended to accomplish at least three interrelated goals: (1) providing the utility an additional incentive to participate in the CPRE Program, at least up to the 30% limitation on utility-developed renewable energy facilities, (2) providing other market participants incentive to behave efficiently by forcing them to compete with other market participants and the utilities, and (3) putting downward pressure on CPRE Program costs through competition among market participants and limiting the utility's payment at less than forecasted avoided cost rates.

In light of these legislative directives and goals, the appropriate conceptualization of "market price" is simply the price included in a proposal selected by the utility, regardless of whether that proposal was submitted by a utility, an Affiliate, or another participant in the CPRE RFP Solicitation. That price, on an annual basis, determines the amount of costs that are appropriately recovered or revenue that is appropriately collected through the rider established in G.S. 62-110.8(g). The Commission considered the concept proposed by Duke that would use the term "product" to attempt to quantify the value of the contractual rights under the power purchase agreement not necessarily based upon dollars per megawatt-hour ($/MWh). The Commission declines to adopt this concept because all prices in proposals must be compared to avoided cost rates, which are expressed in $/MWh. The utility or Affiliate is expected to capture all the value in its proposal price, similar to other market participants. Further, the Commission does not understand the CPRE Program to be comparable to market auctions where a clearing price is established. Attempting to graft that regime onto the CPRE Program raises the potential for odd results such as a utility's market-based recovery being more or less than its actual price. Finally, while these principles hold for the purposes of cost recovery, the Commission recognizes, as reflected in this order and the text of the rule, that noneconomic factors should be considered and incorporated into the CPRE RFP Solicitation evaluation factors. Consideration of those factors could, for example, make one of two identically priced proposals more competitive than the other.

Therefore, the Commission determines that it is unnecessary to adopt a definition of "market price" or to address this issue in the level of detail proposed by the parties. Instead, the Commission adopts subsection (j)(2) requiring the utility, when its application for cost recovery proposes recovery on a market basis, to specifically address the calculation of its costs or revenue on a market basis by testimony sufficient to demonstrate that the proposed recovery is in the public interest.

Procedure to Modify or Delay CPRE Program Requirements

The three disputed issues related to the implementation of the procedure for delay or modification of the CPRE Program requirements in subsection (i)(2) of the proposed rule are: (1) the appropriate burden of persuasion required to justify a modification or delay, (2) whether a modification or delay should be allowed during the Initial CPRE Program Procurement Period, and (3) the level of detail required in a filing requesting a delay or modification.

The Commission determines that NCCEBA and NCSEA's proposed requirement that a utility make a "clear and convincing showing" that a delay or modification is in the public interest inappropriately applies a heightened burden of persuasion. NCSEA's argument in support of its proposal is that no other standard is set forth in G.S. 62-110.8 and, accordingly, the "baseline" standard should be strict compliance with the law. The Commission concludes that in the absence of express legislative intent indicating otherwise, the generally applicable standard, preponderance of the evidence, should apply. Generally, the Commission only requires clear and convincing evidence in unusual or extraordinary cases, for example, requests for deferral treatment of unusual costs.[1] The General Assembly has directed the Commission to establish a procedure to modify or delay the CPRE Program requirements when the Commission determines it is in the public interest to do so. The Commission determines that this directs it to undertake a broad inquiry, weighing any relevant factors brought to the Commission's attention, and should not require a heightened burden of persuasion.

The Commission is also concerned that NCCEBA and NCSEA's proposed limitation on the availability of modification or delay during the intitial CPRE Program Procurement Period would inappropriately limit the Commission's discretion, which the General Assembly has expressly required the Commission to exercise. The Commission concludes, based on the plain language of the statute, that the intent of the General Assembly is to allow the Commission flexibility to address the CPRE Program requirements in light of unforeseen circumstances.

The Commission also concludes that NCCEBA and NCSEA's proposed subsection (i)(2) is overly prescriptive as to the contents of a petition seeking a modification or delay. The Commission generally agrees that a showing of reasonable efforts to comply, supported by an explanation that includes when compliance might be achieved, are matters that should be included in a petition to modify or delay the CPRE Program requirements. However, the Commission determines that it is prudent to leave this level of detail to the proceeding on such a petition. In the proceeding, if the petition falls short of demonstrating the requested relief is in the public interest, then the Commission expects the Public Staff or other parties would present those arguments to the Commission, and the Commission would proceed appropriately. Therefore, the Commission adopts subsection (i)(2) as proposed by Duke and agreed to by the Public Staff.

[1] . See, e.g., Order Establishing Reporting Requirements for Progress Energy Carolinas, Inc., and Dominion North Carolina Power, at 20, issued October 18, 2011 (Docket No. E-100, Sub 112); and Order Denying Deferral Accounting for Warren County Combined Cycle Generating Facility, at 24, issued March 29, 2016 (Docket No. E-22, Sub 519).

Issues Not Addressed in the Proposed Rules.

The Commission notes that neither the proposed rules nor Rule R8-71 adopted herein address the details of the CPRE Program Methodology or the evaluation factors for a CPRE RFP Solicitation. This is appropriate in light of the forthcoming initial CPRE Program filings, which are required to include proposed evaluation factors used in the evaluation of proposals. In reviewing the parties' proposed rules and in developing Rule R8-71, the Commission considered the State purchase and contract laws. See, generally, G.S. Ch. 143, Art. 3. Two features of those laws, and long-standing aspects of State policy, are the promotion of opportunity for historically underutilized businesses, see, e.g., G.S. 143-128.4, and the prohibition of discrimination based upon race, religion, color, national origin, age, sex, or handicap. See G.S. 7A-761, et. seq., and 143-422.2. While the Commission recognizes that the CPRE Program is not readily comparable to public contracting generally, the Commission will require Duke to incorporate into the CPRE Program appropriate features that promote opportunity for historically underutilized business and prohibit discrimination based upon race, religion, color, national origin, age, sex, or handicap.

CONCLUSION

Based upon the foregoing and the entire record in this proceeding, the Commission amends Rules R8-64(a)(1) and R8-66(b) and adopts Rule R8-71, as set forth in Appendix A to this order, incorporating the conclusions reached herein. The Commission also adopts, as part of the appendix to Chapter 8, a form public notice that shall be used by electric public utilities to give public notice of filing of preliminary plans to make an application for a CPCN under the expedited procedure established in Rule R8-71(k), and which is set forth in Appendix B to this order. Finally, the Commission notes that it has made a number of edits to the proposed rules for formatting and style.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of November, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

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Commission Rule R8-64(a)(1) is amended to read as follows:

R8-64 APPLICATION FOR CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY BY CPRE PROGRAM PARTICIPANT, QUALIFYING COGENERATOR, OR SMALL POWER PRODUCER; PROGRESS REPORTS.

(a) Scope of Rule.

(1) This rule applies to applications for a certificate of public convenience and necessity pursuant to G.S. 62-110.1(a) filed by any person, other than an electric public utility, who is an owner of a renewable energy facility that is participating in the Competitive Procurement of Renewable Energy Program established in G.S. 62-110.8, or by any person who is seeking the benefits of 16 U.S.C. 824a-3 or G.S. 62-156 as a qualifying cogenerator or a qualifying small power producer as defined in 16 U.S.C. 796(17) and (18), or as a small power producer as defined in G.S. 62-3(27a), except persons exempt from certification by the provisions of G.S. 62-110.1(g).

...

Commission Rule R8-66 is amended to read as follows

R8-66 REGISTRATION OF RENEWABLE ENERGY FACILITIES; ANNUAL REPORTING REQUIREMENTS.

...

(b) The owner, including an electric power supplier, of each renewable energy facility, whether or not required to obtain a certificate of public convenience and necessity pursuant to G.S. 62-110.1, that intends for renewable energy certificates it earns to be eligible for use by an electric power supplier to comply with G.S. 62-133.8, or for its facility to participate in the Competitive Procurement of Renewable Energy Program, shall register the facility with the Commission. The registration statement may be filed separately or together with an application for a certificate of public convenience and necessity, or with a report of proposed construction by a person exempt from the certification requirement. All relevant renewable energy facilities shall be registered prior to their having RECs issued in the North Carolina Renewable Energy Tracking System (NC-RETS) pursuant to Rule R8-67(h). Contracts for power supplied by an agency of the federal government are exempt from the requirement to register and file annually with the Commission if the renewable energy certificates associated with the power are bundled with the power purchased by the electric power supplier.

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Commission Rule R8-71 is adopted as follows:

Rule R8-71 COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY.

(a) Purpose. - The purpose of this rule is to implement the provisions of G.S. 62-110.8, and to provide for Commission oversight of the CPRE Program(s) designed by the electric public utilities subject to G.S. 62-110.8 for the competitive procurement and development of renewable energy facilities in a manner that ensures continued reliable and cost-effective electric service to customers in North Carolina.

(b) Definitions.

(1) "Affiliate" is defined as provided in G.S. 62-126.3(1).

(2) "Avoided cost rates" – means an electric public utility's calculation of its long-term, levelized avoided energy and capacity costs utilizing the methodology most recently approved or established by the Commission as of 30 days prior to the date of the electric public utility's upcoming CPRE RFP Solicitation for purchases of electricity from qualifying facilities pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978, as amended. The electric public utility's avoided cost rates shall be used for purposes of determining the cost effectiveness of renewable energy resources procured through a CPRE RFP Solicitation. With respect to each CPRE RFP Solicitation, the electric public utility's avoided costs shall be calculated over the time period of the utility's pro forma contract(s) approved by the Commission.

(3) "Competitive Procurement of Renewable Energy (CPRE) Program" means the program(s) established by G.S. 62-110.8 requiring Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, to jointly or individually procure an aggregate 2,660 megawatts (MW) of renewable energy resource nameplate capacity subject to the requirements and limitations established therein.

(4) "CPRE Program Methodology" means the methodology used to evaluate all proposals received in a given CPRE RFP Solicitation.

(5) "CPRE Program Procurement Period" means the initial 45-month period in which the aggregate 2,660 MW of renewable energy resource nameplate capacity is required to be procured under the CPRE Program(s) approved by the Commission.

(6) "CPRE RFP Solicitation" means a request for proposal solicitation process to be followed by the electric public utility under this Rule for the competitive procurement of renewable energy resource capacity pursuant to the utility's CPRE Program.

(7) "Evaluation Team" means employees and agents of an electric public utility that will be evaluating proposals submitted in response to the CPRE RFP Solicitation, including those acting for or on behalf of the electric public utility

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regarding any aspect of the CPRE RFP Solicitation evaluation or selection process.

(8) "IA Website" means the website established and maintained by the Independent Administrator as required by subsection (d)(7) of this Rule.

(9) "Independent Administrator" means the third-party entity to be approved by the Commission that is responsible for independently administering the CPRE Program in accordance with G.S. 62-110.8 and this rule, developing and publishing the CPRE Program Methodology, and for ensuring that all responses to a CPRE RFP Solicitation are treated equitably.

(10) "Electric public utility" means an electric public utility that is required to comply with the requirements of G.S. 62-110.8.

(11) "Market participant" means a person who has expressed interest in submitting a proposal in response to a CPRE RFP Solicitation or has submitted such a proposal, including, unless the context requires otherwise, an Affiliate or an electric public utility, through its Proposal Team.

(12) "Proposal Team" means employees and agents of an electric public utility or an Affiliate that proposes to meet a portion of its CPRE Program requirements as provided in G.S. 62-110.8(b)(i) or (ii), which is more particularly described as a "Self-developed Proposal" in subsection (f)(2)(iv) of this rule, who directly support the Self-developed Proposal.

(13) "Renewable energy certificate" is defined as provided in G.S. 62-133.8(a)(6).

(14) "Renewable energy facility" means an electric generating facility that uses renewable energy resource(s) as its primary source of fuel, has a nameplate capacity rating of 80 MW or less, and is placed into service after the beginning of the CPRE Program Procurement Period.

(15) "Renewable energy resource" is as defined as provided in G.S. 62-133.8(a)(8).

(c) Initial CPRE Program Filings and Program Guidelines

(1) Each electric public utility shall develop and seek Commission approval of guidelines for the implementation of its CPRE Program and to inform market participants regarding the terms and conditions of, and process for participating in, the CPRE Program. The electric public utility shall file its initial CPRE Program guidelines at the time it initially proposes a CPRE Program for Commission approval. The CPRE Program guidelines should, at minimum, include the following.

(i) Planned allocation between the electric public utilities of the 2,660 MW required to be procured during the CPRE Program Procurement Period;

(ii) Proposed timeframe for each electric public utility's initial CPRE RFP Solicitation(s) and planned initial procurement amount, as well as plans for additional CPRE RFP Solicitation(s) during the CPRE Program Procurement Period;

(iii) Minimum requirements for participation in the electric public utility's initial CPRE RFP Solicitation(s);

(iv) Proposed evaluation factors, including economic and noneconomic factors, for the evaluation of proposals submitted in response to CPRE RFP Solicitation(s); and

(v) Pro forma contract(s) to be utilized in the CPRE Program.

(2) At the time an electric public utility files its proposed CPRE Program guidelines with the Commission, it shall also identify any regulatory conditions and/or provisions of the electric public utility's code of conduct that the electric public utility seeks to waive for the duration of the CPRE Program Procurement Period pursuant to G.S. 62-110.8(h)(2).

(d) Selection and Role of Independent Administrator.

(1) In advance of the filing the initial CPRE Program required by subsection (c) of this Rule, the Commission shall invite and consider comments and recommendations from the electric public utilities, the Public Staff, and other interested persons, including market participants, regarding the selection of the Independent Administrator. In addition to the requirements in this Rule, the Commission may establish additional minimum qualifications and requirements for the Independent Administrator.

(2) Any person requesting to be considered for approval as the Independent Administrator shall be required to disclose any financial interest involving the electric public utilities implementing CPRE Programs or any market participant, including, but not limited to, all substantive assignments for electric public utilities, Affiliate(s), or market participant during the preceding three (3) years.

(3) In advance of the initial CPRE RFP Solicitation(s), the Commission shall select and approve the Independent Administrator. From the date the Independent Administrator is selected, no market participant shall have any communication with the Independent Administrator or the electric public utility pertaining to the CPRE RFP Solicitation, the RFP documents and process, or the evaluation process or any related subjects, except as those communications are specifically allowed by this rule.

(4) The Independent Administrator will be retained by the electric public utility or jointly by the electric public utilities for the duration of the CPRE Program Procurement Period under a contract to be filed with the Commission at least sixty (60) days prior to the public utilities' initial CPRE RFP Solicitation(s). The Independent Administrator shall remain subject to ongoing Commission oversight as part of the Commission's review of the electric public utilities' annual CPRE Program Compliance Reports.

(5) The Independent Administrator's duties shall include:

(i) Monitor compliance with CPRE Program requirements.

(ii) Review and comment on draft CPRE Program filings, plans, and other documents.

(iii) Facilitate and monitor permissible communications between the electric public utilities' Evaluation Team and other participants in the CPRE RFP solicitations.
(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.
(v) Receive and transmit proposals.
(vi) Independently evaluate the proposals.
(vii) Monitor post-proposal negotiations between the electric public utilities' Evaluation Team(s) and participants who submitted winning proposals.
(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).

(6) Prior to the initial CPRE RFP Solicitation, but on or before the date determined by Commission order, Independent Administrator shall develop and publish the CPRE Program Methodology. Prior to developing and publishing the CPRE Program Methodology, the Independent Administrator shall meet with the Evaluation Team(s) to share evaluation techniques and practices. The Independent Administrator shall also meet with the Evaluation Team(s) at least 60 days prior to each subsequent CPRE RFP Solicitation to discuss the efficacy of the CPRE Program Methodology and whether changes to the CPRE Program Methodology may be appropriate based upon the anticipated contents of the next CPRE RFP Solicitation. If the CRPE RFP Solicitation allows for electric public utility self-build options or Affiliate proposals, the Independent Administrator shall ensure that if any non-publicly available transmission or distribution system information is used in preparing proposals by the electric public utility or Affiliate(s), such information is made available to third parties that notified the Independent Administrator or their intent to submit a proposal in response to the that CPRE RFP Solicitation.

(7) The Independent Administrator shall maintain the IA Website to support administration and implementation of the CPRE Program and shall post the CPRE RFP Solicitation documents, the CPRE Program Methodology, participant FAQs, and any other pertinent documents on the IA Website.

(8) In carrying out its duties, the Independent Administrator shall work in coordination with the Evaluation Team(s) with respect to CPRE Program

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implementation and the CPRE RFP Solicitation proposal evaluation process in the manner and to the extent as more specifically provided in subsection (f) of this rule.

(9) If the Independent Administrator becomes aware of a violation of any CPRE

Program requirements, the Independent Administrator shall immediately report that violation, together with any recommended remedy, to the Commission.

(10) The Independent Administrator's fees shall be funded through reasonable proposal fees collected by the electric public utility. The electric public utility shall be authorized to collect proposal fees up to $10,000 per proposal to defray its costs of evaluating the proposals. In addition, the electric public utility may charge each participant an amount equal to the estimated total cost of retaining the Independent Administrator divided by the reasonably anticipated number of proposals. To the extent that insufficient funds are collected through these methods to pay of the total cost of retaining the Independent Administrator, the electric public utility shall pay the balance and subsequently charge the winning participants in the CPRE RFP Solicitation.

(e) Communications Between CPRE Market Participants.

(1) From the date an electric public utility announces a CPRE RFP Solicitation, until the Independent Administrator declares the CPRE RFP Solicitation closed, there shall be no communications between market participants regarding the substantive aspects of their proposals or between the electric public utility and market participants. Such communications shall be conducted through the Independent Administrator as permitted by this subsection.

(2) The Evaluation Team or the Independent Administrator may request further information from any market participant regarding its proposal during the process of evaluating and selecting proposals. These communications shall be conducted through the Independent Administrator and shall be conducted in a manner that keeps confidential the identity of the market participant.

(3) On or before the date an electric public utility announces a CPRE RFP Solicitation, the Proposal Team shall be separately identified and physically segregated from the Evaluation Team for purposes of all activities that are part of the CPRE RFP Solicitation process. The names and job titles of each member of the Proposal Team and the Evaluation Team shall be reduced to writing and submitted to the Independent Administrator.

(4) There shall be no communications, either directly or indirectly, between the Proposal Team and Evaluation Team during the CPRE RFP Solicitation regarding any aspect of the CPRE RFP Solicitation process, except (i) necessary communications as may be made through the Independent Administrator and (ii) negotiations between the Proposal

Team and the Evaluation Team for a final power purchase agreement after the Proposal Team has been selected by the electric public utility as a winning proposal. The Evaluation Team will have no direct or indirect contact or communications with the Proposal Team or any other participant, except through the Independent Administrator as described further herein, until such time as a winning proposal or proposals are selected by the electric public utility and negotiations for a final power purchase agreement(s) have begun.

(5) At no time shall any information regarding the CPRE RFP Solicitation process be shared with any market participant, including the Proposal Team, unless the information is shared with all competing participants contemporaneously and in the same manner.

(6) Within fifteen (15) days of the date an electric public utility announces a planned CPRE RFP Solicitation, each member of the Proposal Team shall execute an acknowledgement that he or she agrees to abide by the restrictions and conditions contained in subsection (e) of this rule for the duration of the CPRE RFP Solicitation. If the Proposal Team's proposal is selected by the electric public utility after completion of the CPRE RFP Solicitation, each member of the Proposal Team shall then also execute an acknowledgement that he or she has met the restrictions and conditions contained in subsection (e) of this rule. The electric public utility shall provide these acknowledgements to the Independent Administrator and shall file the acknowledgements with the Commission in support of its annual CPRE Compliance Report.

(7) Should any participant, including an Affiliate or electric public utility's Proposal Team, attempt to contact a member of the Evaluation Team directly, such participant shall be directed to the Independent Administrator for all information and such communication shall be reported to the Independent Administrator by the Evaluation Team member. Within ten (10) days of the date that the Independent Administrator issues the CPRE RFP Solicitation, each Evaluation Team member shall execute an acknowledgement that he or she agrees to abide by the conditions contained in subsection (e) of this rule for the duration of the CPRE RFP Solicitation. If the Proposal Team's proposal is selected by the electric public utility after completion of the CPRE RFP Solicitation, the Evaluation Team shall also execute an acknowledgement that he or she has met the restrictions and conditions contained in subsection (e)(3)-(5) above. The electric public utility shall provide these acknowledgements to the Independent Administrator and shall file the acknowledgements with the Commission in support of its annual CPRE Compliance Report.

(f) CPRE RFP Solicitation Structure and Process.

(1) Identification of Market Participants; Design of CPRE RFP Solicitation.

(i) Prior to the initial CPRE RFP Solicitation, the electric public utility shall provide the Independent Administrator with a list of potential market participants that have expressed interest, in writing, in

participating in the CPRE RFP Solicitation or have participated in recent renewable energy resource solicitations issued by the electric public utilities. The Independent Administrator shall publish notice of the draft CPRE RFP Solicitation on the IA Website, and prepare the list of potential participants to whom notice of the upcoming CPRE RFP Solicitation will be sent.

(ii) The electric public utility shall prepare an initial draft of the CPRE RFP Solicitation guidelines and documents, including RFP procedures, evaluation factors, credit and security obligations, a pro forma power purchase agreement, the Avoided Cost Rate against which proposals will be evaluated, and a planned schedule for completing the CPRE RFP Solicitation and selecting winning proposals. No later than sixty (60) days prior to the planned issue date of the CPRE RFP Solicitation, the electric public utility shall provide the initial draft of the CPRE RFP Solicitation guidelines and documents to the Independent Administrator for posting on the IA Website.

(iii) The evaluation factors included in the CPRE RFP Solicitation guidelines shall identify all economic and noneconomic factors to be considered by the Independent Administrator in its evaluation of proposals. In addition to the guidelines, a pro forma power purchase agreement containing all expected material terms and conditions shall be included in the CPRE RFP Solicitation documents provided to the Independent Administrator and shall be filed with the Commission at least thirty (30) days prior to the planned CPRE RFP solicitation issuance date.

(iv) The Independent Administrator, in coordination with the electric public utility, may conduct a pre-issuance market participants' conference to publicly discuss the draft CPRE RFP Solicitation guidelines and documents with market participants. Market participants may submit written questions or recommendations to the Independent Administrator regarding the draft CPRE RFP Solicitation guidelines and documents in advance of the market participants' conference. All such questions and recommendations shall be posted on the IA Website. The Independent Administrator shall have no private communication with any potential participants regarding any aspect of the draft CPRE RFP Solicitation documents.

(v) Based on the input received from potential participants, and on its own review of the draft CPRE RFP Solicitation documents, the Independent Administrator shall submit a report to the electric public utility, at least twenty (20) days prior to the planned CPRE RFP Solicitation issuance date, detailing market participants' comments and the Independent Administrator's recommendations for changes to the CPRE RFP Solicitation documents, if any. This report shall also be posted on the IA Website for review by potential participants.

(vi) At least five (5) days prior to the planned CPRE RFP Solicitation issuance date, the electric public utility shall submit its final version of the CPRE RFP Solicitation documents to the Independent Administrator to be posted on the IA Website.

(vii) At any time after the CPRE RFP Solicitation is issued, through the time winning proposals are selected by the electric public utility, the schedule for the solicitation may be modified upon mutual agreement of the electric public utility and the Independent Administrator, with equal notice provided to all market participants, or upon approval by the Commission. Any modification to the CPRE RFP Solicitation schedule will be posted to the IA Website.

(2) Issuance of CPRE RFP Solicitation.

(i) The Independent Administrator shall transmit the final CPRE RFP Solicitation to the market participants via the IA Website. Upon issuance of the final CPRE RFP Solicitation, the only communications permitted prior to submission of proposals shall be conducted through the Independent Administrator. Participants' questions and the Independent Administrator's responses shall be posted on the IA Website, but, to the extent possible, shall be posted in a manner that the identity of the participant remains confidential. To the extent such questions and responses contain competitively sensitive information that a particular participant deems to be a trade secret, this information may be redacted by the participant.

(ii) The electric public utility shall not communicate with any market participant regarding the RFP Process, the content of the CPRE RFP Solicitation documents, or the substance of any potential response by a participant to the RFP; provided, however, the electric public utility shall provide timely, accurate responses to the Independent Administrator's request for information regarding any aspect of the CPRE RFP Solicitation documents or the CPRE RFP Solicitation process.

(iii) Participants shall submit proposals pursuant to the solicitation schedule contained in the CPRE RFP Solicitation, and in the format required by the Independent Administrator to facilitate the evaluation and selection of proposals. The Independent Administrator shall have access to all proposals and all supporting documentation submitted by market participants in the course of the CPRE RFP Solicitation process.

(iv) If the electric public utility wishes to consider an option for full or partial ownership of a renewable energy facility as part of the CPRE RFP solicitation, the utility must submit its construction proposal (Self-developed Proposal) to provide all or part of the capacity requested in the CPRE RFP solicitation to the Independent Administrator at the time all other proposals are due. Once submitted, the Self-developed Proposal may not be modified, except in the event that the electric public utility demonstrates to the satisfaction of the Independent Administrator that the Self-developed Proposal contains an error and that correction of the error will not be unduly harmful to the other market participants, the electric public utility may correct the error. Persons who have participated or assisted in the preparation of the Self-developed Proposal on behalf of the electric public utility's Proposal Team in any way may not be a member of the Affiliate's Proposal Team, nor communicate with the Affiliate's Proposal Team during the RFP Process about any aspect of the RFP Process.

(3) Evaluation and Selection of Proposals. The evaluation and selection of proposals received in response to a CPRE RFP Solicitation shall proceed in two steps as set forth in this subdivision, and shall be subject to the Commission's oversight as provided in G.S. 62-110.8 and this rule.

(i) In step one, the Independent Administrator shall evaluate all proposals based upon the CPRE RFP Solicitation evaluation factors using the CPRE Program Methodology. The Independent Administrator shall conduct this evaluation in an appropriate manner designed to ensure equitable review of all proposals based on the economic and noneconomic factors contained in the CPRE RFP Solicitation evaluation factors. As a result of the Independent Administrator's evaluation, the Independent Administrator shall eliminate proposals that fail to meet the CPRE RFP Solicitation evaluation factors and shall develop and deliver to the electric public utility a list of proposals ranked in order from most competitive to least competitive. The Independent Administrator shall redact from the proposals any information that identifies the market participant that submitted the proposal and any information in the proposal that is not reasonably necessary for the utility to complete step two of the evaluation process, including economic factors such as cost and pricing information.

(ii) In step two, the electric public utility shall select the proposals in the order ranked by the Independent Administrator until the total generating capacity sought in the CPRE RFP Solicitation is satisfied, provided, however, that if the electric public utility determines that the interconnection and operation of a proposed facility, together with a facility or multiple facilities that were the subject of proposal(s) already selected by the utility, would significantly undermine the utility's ability to provide adequate and reliable electric service to its customers, then the electric public utility may eliminate such proposal(s) from further consideration. The electric public utility shall notify the Independent Administrator of the proposals it has selected and those it has eliminated, if any. If the electric public utility eliminates proposal(s), it shall provide to the Independent Administrator a short and plain explanation of why each proposal was eliminated at the same time that the utility notifies the Independent Administrator of the proposals it has selected.

(iii) Upon receipt of notification of proposals selected by the electric public utility, the Independent Administrator shall provide the electric public utility with the identity of the market participants that submitted proposals selected and shall publish the list of proposals selected and the utility's explanation(s) for eliminating proposal(s), if any. Upon publication of the list of proposals selected and the utility's explanation(s), if any, the Independent Administrator shall declare the CPRE RFP Solicitation closed.

(iv) The electric public utility shall proceed to execute contracts with each of the market participants who submitted a proposal that was selected.

(g) CPRE Program Plan.

(1) Each electric public utility shall file its initial CPRE Program plan with the Commission at the time initial CPRE Program Guidelines are filed under subsection (c) and thereafter shall be filed on or before September 1 of each year. The electric public utility may file its CPRE Program plan as part of its future biennial integrated resource plan filings, or update thereto, and the CPRE Program plan filed pursuant to this rule will be reviewed in the same docket as the electric public utility's biennial integrated resource plan or update filing.

(2) Each year, beginning in 2018, each electric public utility shall file with the Commission an updated CPRE Program plan covering the remainder of the CPRE Program Procurement Period. At a minimum, the plan shall include the following information:

(i) an explanation of whether the electric public utility is jointly or individually implementing the aggregate CPRE Program requirements mandated by G.S. 62-110.8(a);

(ii) a description of the electric public utility's planned CPRE RFP Solicitations and specific actions planned to procure renewable energy resources during the CPRE Program planning period;

(iii) an explanation of how the electric public utility has allocated the amount of CPRE Program resources projected to be procured during the CPRE Program Procurement Period relative to the aggregate CPRE Program requirements;

(iv) if designated by location, an explanation of how the electric public utility has determined the locational allocation within its balancing authority area;

(v) an estimate of renewable energy generating capacity that is not subject to economic dispatch or economic curtailment that is under development and projected to have executed power purchase agreements and interconnection agreements with the electric public utility or that is otherwise projected to be installed in the electric public utility's balancing authority area within the CPRE Program planning period; and

(vi) a copy of the electric public utility's CPRE Program guidelines then in effect as well as a pro forma power purchase agreement used in its most recent CPRE RFP Solicitation.

(3) Upon the expiration of the CPRE Program Procurement Period, the electric public utility shall file a CPRE Program Plan in the following calendar year identifying any additional CPRE Program procurement requirements, as provided for in G.S. 62-110.8(a).

(4) In any year in which an electric public utility determines that it has fully complied with the CPRE Program requirements set forth in G.S. 62-110.8(a), the electric public utility shall notify the Commission in its CPRE Program Plan, and may petition the Commission to discontinue the CPRE Program Plan filing requirements beginning in the subsequent calendar year.

(h) CPRE Program Compliance Report.

(1) Each electric public utility shall file its annual CPRE Program compliance report, together with direct testimony and exhibits of expert witnesses, on the same date that it files its application to recover costs pursuant to subsection (j) of this rule. The Commission shall consider each electric public utility's CPRE Program compliance report at the hearing provided for in subsection (j) and shall determine whether the electric public utility is in compliance with the CPRE Program requirements of G.S. 62-110.8.

(2) Beginning in 2019, and each year thereafter, each electric public utility shall file with the Commission a report describing the electric public utility's competitive procurement of renewable energy resources under its CPRE Program and ongoing actions to comply with the requirements of G.S. 62-110.8 during the previous calendar year, which shall be the "reporting year." The report shall include the following information, including supporting documentation:

(i) a description of CPRE RFP Solicitation(s) undertaken by the electric public utility during the reporting year, including an identification of each proposal eliminated pursuant to subsection (f)(3)(ii) of this rule and an explanation of the utility's basis for elimination of each proposal;

(ii) a description of the sources, amounts, and costs of third-party power purchase agreements and proposed authorized revenues for utility-owned assets for renewable energy resources procured through CPRE RFP Solicitation(s) during the reporting year, including the dates of all CPRE Program contracts or utility commitments to procure renewable energy resources during the reporting year;

(iii) the forecasted nameplate capacity and megawatt-hours of renewable energy and the number of renewable energy certificates obtained through the CPRE Program during the reporting year;

(iv) identification of all proposed renewable energy facilities under development by the electric public utility that were proposal into a CPRE RFP Solicitation during the reporting year, including whether any non-publicly available transmission or distribution system operations information was used in preparing the proposal, and, if so, an explanation of how such information was made available to third parties that notified the utility of their intention to submit a proposal in the same CPRE RFP Solicitation;

(v) the electric public utility's avoided cost rates applicable to the CPRE RFP Solicitation(s) undertaken during the reporting year and confirmation that all renewable energy resources procured through a CPRE RFP Solicitation are priced at or below the electric public utility's avoided cost rates;

(vi) the actual total costs and authorized revenues incurred by the electric public utility during the calendar year to comply with G.S. 62-110.8;

(vii) the status of the electric public utility's compliance with the aggregate CPRE Program procurement requirements set forth in G.S. 62-110.8(a);

(viii) a copy of the contract then in effect between the electric public utility and Independent Administrator, supporting information regarding the administrative fees collected from participants in the CPRE RFP Solicitation during the reporting year, as well as any cost incurred by the electric public utility during the reporting year to implement the CPRE RFP Solicitation; and

(ix) certification by the Independent Administrator that all public utility and third-party proposal responses were evaluated under the published CPRE Program Methodology and that all proposals were treated equitably through the CPRE RFP Solicitation(s) during the reporting year.

(i) Compliance with CPRE Program Requirements.

(1) An electric public utility shall be in compliance with the CPRE Program requirements during a given year where the Commission determines that the electric public utility's CPRE Program plan is reasonably designed to meet the requirements of G.S. 62-110.8 and, based on the utility's most recently filed CPRE Program compliance report, that the electric public utility is reasonably and prudently implementing the CPRE Program requirements.

(2) An electric public utility, or other interested party, may petition the Commission to modify or delay the provisions of G.S. 62-110.8 in whole or

in part. The Commission shall allow a modification or delay upon finding that it is in the public interest to do so.

(3) Renewable energy certificates purchased or earned by an electric public utility while complying with G.S. 62-110.8 must have been earned after January 1, 2018, and may be retired to meet an electric public utility's REPS compliance obligations under G.S. 62-133.8.

(4) The owner of any renewable energy facility included as part of a proposal selected through a CPRE RFP Solicitation shall register the facility as a new renewable energy facility under Rule R8-66 no later than 60 calendar days from receiving written notification that the facility was included as part of a proposal selected and shall participate in the North Carolina Renewable Energy Tracking System (NC-RETS) to facilitate the issuance or importation of renewable energy certificates contracted for under the CPRE Program.

(j) Cost or authorized revenue recovery.

(1) Beginning in 2018, for each electric public utility, the Commission shall schedule an annual public hearing pursuant to G.S. 62-110.8(g) to review the costs incurred or anticipated to be incurred by the electric public utility to comply with G.S. 62-110.8. The annual rider hearing for each electric public utility will be scheduled as soon as practicable after the hearing held by the Commission for the electric public utility under Rule R8-55.

(2) The Commission shall permit each electric public utility to charge an increment or decrement as a rider to its rates to recover in a timely manner the reasonable and prudent costs incurred and anticipated to be incurred to implement its CPRE Program and to comply with G.S. 62-110.8. In any application for cost recovery and collection of authorized revenues wherein the utility proposes to recover costs or collect revenues attributable to a utility-owned renewable energy facility calculated on a market basis, in lieu of a cost-of-service basis, the utility shall support its application with testimony specifically addressing the calculation of those costs and revenues sufficient to demonstrate that recovery on a market basis is in the public interest.

(3) 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.

(4) Rates set pursuant to this section shall be recovered during a fixed recovery 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.

(5) The costs and authorized revenue will be further modified through the use of a CPRE Program experience modification factor (CPRE EMF) rider. The CPRE EMF rider will reflect the difference between reasonable and prudently-incurred CPRE Program projected costs, authorized revenue, and the revenues that were actually realized during the test period under the CPRE Program rider then in effect. Upon request of the electric public

utility, the Commission shall also incorporate in this determination the experienced over-recovery or under-recovery of the costs and authorized revenue up to 30 days prior to the date of the hearing, provided that the reasonableness and prudence of these costs and authorized revenues shall be subject to review in the utility's next annual CPRE Program cost recovery hearing.

(6) The CPRE EMF rider will remain in effect for a fixed 12-month period following establishment and will carry through as a rider to rates established in any intervening general rate case proceedings.

(7) Pursuant to G.S. 62-130(e), any over-collection of reasonably and prudently-incurred costs and authorized revenues to be refunded to an electric public utility's customers through operation of the CPRE EMF rider shall include an amount of interest, at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate.

(8) Each electric public utility shall follow deferred accounting with respect to the difference between actual reasonably and prudently-incurred costs or authorized revenue and related revenues realized under rates in effect.

(9) The annual increase in the aggregate amount of costs recovered under 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 total North Carolina retail jurisdictional gross revenues for the preceding calendar year determined as of December 31 of the previous calendar year. Any amount in excess of that limit shall be carried over and recovered in the next recovery period when the annual increase in the aggregate amount of costs to be recovered is less than one percent (1%).

(10) Each electric public utility, at a minimum, shall submit to the Commission for purposes of investigation and hearing the information required for the CPRE Program compliance report for the 12-month test period established in subsection (3) consistent with Rule R8-55, accompanied by supporting workpapers and direct testimony and exhibits of expert witnesses, and any change in rates proposed by the electric public utility at the same time that it files the information required by Rule R8-55.

(11) The electric public utility shall publish a notice of the annual hearing for 2 successive weeks in a newspaper or newspapers having general circulation in its service area, normally beginning at least 30 days prior to the hearing, notifying the public of the hearing before the Commission pursuant to G.S. 62-110.8(g) and setting forth the time and place of the hearing.

(12) Persons having an interest in said hearing may file a petition to intervene setting forth such interest at least 15 days prior to the date of the hearing. Petitions to intervene filed less than 15 days prior to the date of the hearing may be allowed at the discretion of the Commission for good cause shown.

(13) The Public Staff and intervenors shall file direct testimony and exhibits of expert witnesses at least 15 days prior to the hearing date. If a petition to

intervene is filed less than 15 days prior to the hearing date, it shall be accompanied by any direct testimony and exhibits of expert witnesses the intervenor intends to offer at the hearing.

(14) The electric public utility may file rebuttal testimony and exhibits of expert witnesses no later than 5 days prior to the hearing date.

(15) The burden of proof as to whether CPRE Program-related costs or authorized revenues to be recovered under this section were reasonable and prudently-incurred shall be on the electric public utility.

(k) Expedited review and approval of Certificate of Public Convenience and Necessity for renewable energy facilities owned by an electric public utility and procured under the CPRE Program.

(1) Scope of Section.

(i) This section applies to applications for a certificate of public convenience and necessity pursuant to G.S. 62-110.8(h)(3) filed by an electric public utility for the construction and operation of renewable energy facilities owned by an electric public utility for compliance with the requirements of G.S. 62-110.8, and to petitions to transfer a certificate of public convenience and necessity to an electric public utility for compliance with the requirements of G.S. 62-110.8. Applications and petitions filed pursuant to this subsection shall be required to comply with the requirements of this subsection and shall not otherwise be required to comply with the requirements of G.S. 62-82 or 62-110.1, or Commission Rules R8-61 or R8-64.

(ii) The construction of a renewable energy facility for the generation of electricity shall include not only the building of a new building, structure or generator, but also the renovation or reworking of an existing building, structure or generator in order to enable it to operate as a generating facility.

(iii) This section shall apply to any person within its scope who begins construction of a renewable energy facility without first obtaining a certificate of public convenience and necessity. In such circumstances, the application shall include an explanation for the applicant's beginning of construction before the obtaining of the certificate.

(iv) This section applies to a petition to transfer an existing certificate of public convenience and necessity issued for renewable energy facilities that an electric public utility acquires from a third party with the intent to own and operate the renewable energy facility to comply with the requirements of G.S. 62-110.8.

(2) The Application. The application shall be comprised of the following exhibits:

(i) Exhibit 1 shall contain:

1. The full and correct name, business address, business telephone number, and electronic mailing address of the electric public utility;
2. A statement describing the electric public utility's corporate structure and affiliation with any other electric public utility, if any; and
3. The ownership of the facility site and, if the owner is other than the applicant, the applicant's interest in the facility site.

(ii) Exhibit 2 shall contain the following site information:

1. 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, 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 is preferred;
2. The E911 street address, county in which the proposed facility would be located, and GPS coordinates of the approximate center of the proposed facility site to the nearest second or one thousandth of a degree; and
3. Whether the electric public utility is the site owner, and, if not, providing the full and correct name of the site owner and the electric public utility's interest in the site.

(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 production of the renewable energy facility in kilowatt-hours, including a detailed 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.

(iv) Exhibit 3 shall include:

1. A complete list of all federal and state licenses, permits and exemptions required for construction and operation of the renewable energy facility and a statement of whether each has been obtained or applied for; and
2. A copy of those that have been obtained should be filed with the application; a copy of those that have not been obtained at the time of the application should be filed with the Commission as soon as they are obtained.

(v) Exhibit 4 shall contain the expected cost to construct, operate and maintain the proposed facility.

(vi) Exhibit 5 shall contain the following resource planning information:

1. The utility's most recent biennial report and the most recent annual report filed pursuant to Rule R8-60, plus any proposals by the utility to update said reports;
2. The extent to which the proposed facility would conform to the utility's most recent biennial report and the most recent annual report that was filed pursuant to Rule R8-60;
3. A statement of how the facility would contribute to resource and fuel diversity, whether the facility would have dual-fuel capability, and how much fuel would be stored at the site;
4. An explanation of the need for the facility, including information on energy and capacity forecasts; and
5. An explanation of how the proposed facility meets the identified energy and capacity needs, including the anticipated facility capacity factor, heat rate, and service life.

(3) Petition for transfer of certificate of public convenience and necessity. When an electric public utility procures an operating renewable energy facility through a CPRE RFP Solicitation with intent to own and operate the facility and the renewable energy facility has been previously issued a certificate of public convenience and necessity, the electric public utility shall petition the Commission to transfer the certificate of public convenience and necessity. A petition requesting that the Commission transfer a certificate of public convenience and necessity shall include the following:

(i) a description of the terms and conditions of the electric public utility's procurement of the renewable energy facility under the CPRE Program and an identification of any significant changes to the information in the application for the certificate of public convenience and necessity, which the Commission considered in the issuance of the certificate for that facility;

(ii) The signature and verification of the electric public utility's employee or agent responsible for preparing the petition stating that the

contents thereof are known to the employee or agent and are accurate to the best of that person's knowledge; and

(iii) The verification of a person authorized to act on behalf of the certificate holder that it intends to transfer the certificate of public convenience and necessity to the electric public utility.

(4) Procedure for Acquiring Project Development Assets. — When an electric public utility purchases from a third party developer assets that include the rights to construct and operate a renewable energy facility that has been issued a certificate of public convenience and necessity with the intent of further developing the project and submitting the renewable energy facility in to a future CPRE RFP Solicitation, the electric public utility shall provide notice to the Commission in the docket where the certificate of public convenience and necessity was issued that the electric public utility has acquired ownership of the project development assets. The electric public utility shall not be required to submit a petition for transfer of the certificate of public convenience and necessity unless and until the project is selected through a CPRE RFP Solicitation or the electric public utility otherwise elects to proceed with construction of the renewable energy facility. If the project is selected through a CPRE RFP Solicitation or the electric public utility otherwise elects to proceed with construction of the renewable energy facility, the electric public utility shall file a petition to transfer the certificate of public convenience and necessity, and the Commission shall process the petition in the same manner provided in (6) of this subsection. In any event, the petition shall be filed prior to the electric public utility commencing the construction or operation of the renewable energy facility, and no rights under the certificate of public convenience and necessity shall transfer to the electric public utility unless and until the Commission approves transfer of the certificate.

(5) Procedure for expedited review of applications for a certificate of public convenience and necessity. – The Commission will process applications for certificates of public convenience and necessity filed pursuant to this section as follows:

(i) The electric public utility shall file with the Commission its preliminary plans at least 30 days before filing an application for a certificate of public convenience and necessity. The preliminary plans shall include the following:

1. Exhibit 1 shall contain the following site information:
   a. A color map or aerial photo (a U.S. Geological Survey map or an aerial photo map prepared via the State's geographic information system is preferred) showing the proposed site boundary and layout, with all major equipment, including the generator and inverters, planned and existing roads, planned and existing water supplies, and planned and existing electric facilities;

   b. The E911 street address, county in which the proposed facility would be located, and GPS coordinates of the approximate center of the proposed facility site to the nearest second or one thousandth of a degree;
   c. The full and correct name of the site owner and, if the owner is other than the applicant, the applicant's interest in the site;
   d. A brief general description of practicable transmission line routes emanating from the site, including a color map showing their general location; and
   e. The gross, net, and nameplate generating capacity of each unit and the entire facility's total projected dependable capacity in alternating current (AC).
2. Exhibit 2 shall contain a list of all agencies from which approvals will be sought covering various aspects of any generation facility constructed on the site and the title and nature of such approvals; and
3. Exhibit 3 shall include a schedule showing the anticipated beginning dates for construction, testing, and commercial operation of the generating facility.

(ii) Within ten days of the filing of its preliminary plans, the Applicant shall cause to be published a notice of its filing of preliminary plans to apply for an expedited certificate of public convenience and necessity in a newspaper having general circulation in the area where the generating facility. The notice shall be in the form provided in the Appendix to this Chapter, and the applicant shall be responsible for filing with the Commission an affidavit of publication to the effect that the notice was published as required by this rule;

(iii) The Chief Clerk will deliver 2 copies of the electric public utility's preliminary plans 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. The Chief Clerk will request comments from state agencies within 30 days of delivering notice to the Clearinghouse Coordinator.

(iv) The applicant shall file the application within 60 days of filing of its preliminary plans.

(v) The Commission will issue an order requesting the Public Staff to investigate the application and present its findings, conclusions, and recommendations at the Regular Commission Staff Conference to be held on the third Monday following the filing of the application, and requiring the applicant to publish notice of the application and of the time and place of the Staff Conference where the application will be considered. The notice shall be published once in a newspaper of general circulation in the area where the generating facility is

proposed to be constructed. The applicant shall be responsible for filing with the Commission an affidavit of publication to the effect that the notice was published as required by this rule.

(vi) If significant complaint(s) are filed with the Commission prior to the Regular Commission Staff Conference where the application is to be considered, the Public Staff shall report the same to the Commission and the Commission shall schedule a public hearing to determine whether a certificate should be awarded. The Commission will give reasonable notice of the time and place of the hearing to the applicant and to each complaining party, and require the applicant to publish notice of the time and place of the hearing. The notice shall be published once in a newspaper of general circulation in the area where the generating facility is proposed to be constructed. The applicant shall be responsible for filing with the Commission an affidavit of publication to the effect that the notice was published as required by this rule.

(vii) If no significant complaint(s) are received within the time specified, the Commission may, upon its own initiative, order and schedule a hearing to determine whether a certificate should be awarded. The Commission will give reasonable notice of the time and place of the hearing to the applicant and require the applicant to publish notice of the time and place of the hearing. The notice shall be published once in a newspaper of general circulation in the area where the generating facility is proposed to be constructed. The applicant shall be responsible for filing with the Commission an affidavit of publication to the effect that the notice was published as required by this rule.

(viii) The Commission, for good cause shown, may order such additional investigation, further hearings, and required filings as it deems necessary and appropriate to address the issues raised in the application or by parties opposing the issuance of the requested certificate; and

(ix) If no significant complaint(s) are filed with the Commission and the Commission does not order a hearing on its own initiative nor order additional investigation, further hearings, or required filings, then the Commission shall consider the application at the Regular Commission Staff Conference as scheduled and, thereafter, issue an order on the application within 30 days after the application is filed, or as near after the 30^{th} days as reasonably practicable. Where the Commission deems issuance of an order on the application within 30 days is impossible, the Commission may issue a notice of decision within 30 days after the application is filed and subsequently issue a final order in the matter.

(6) Procedure for Expedited Transfer of certificate of public convenience and necessity. — The Commission shall process a petition to transfer a certificate of public convenience pursuant to the CPRE Program as follows:

(i) Any petition to transfer an existing certificate of public convenience and necessity shall be signed and verified by the electric public utility applicant. A petition to transfer an existing certificate of public convenience and necessity shall also be verified by the entity which was initially granted the certificate of public convenience and necessity that it intends to transfer the certificate of public convenience and necessity to the electric public utility.

(ii) The Commission will issue an order requesting the Public Staff to investigate the petition and present its findings, conclusions, and recommendations at the Regular Commission Staff Conference to be held on the third Monday following the filing of the application, and requiring the applicant to publish notice of the petition and of the time and place of the Staff Conference where the application will be considered. The notice shall be published once in a newspaper of general circulation in the area where the generating facility is located. The applicant shall be responsible for filing with the Commission an affidavit of publication to the effect that the notice was published as required by this rule.

(iii) If significant complaint(s) are filed with the Commission prior to the Regular Commission Staff Conference where the petition is to be considered, the Public Staff shall report the same to the Commission and the Commission shall schedule a public hearing to determine whether the petition for transfer of the certificate should be granted. The Commission will give reasonable notice of the time and place of the hearing to the applicant and to each complaining party, and require the applicant to publish notice of the time and place of the hearing. The notice shall be published once in a newspaper of general circulation in the area where the generating facility is located. The applicant shall be responsible for filing with the Commission an affidavit of publication to the effect that the notice was published as required by this rule.

(iv) If no significant complaint(s) are received within the time specified, the Commission may, upon its own initiative, order and schedule a hearing to determine whether a certificate should be awarded. The Commission will give reasonable notice of the time and place of the hearing to the applicant and require the applicant to publish notice of the time and place of the hearing. The notice shall be published once in a newspaper of general circulation in the area where the generating facility is located. The applicant shall be responsible for filing with the Commission an affidavit of publication to the effect that the notice was published as required by this rule.

(v) The Commission, for good cause shown, may order such additional investigation, further hearings, and required filings as it deems necessary and appropriate to address the issues raised in the application or by parties opposing the issuance of the requested certificate; and

(vi) If no significant complaint(s) are filed with the Commission and the Commission does not order a hearing on its own initiative nor order additional investigation, further hearings, or required filings, then the Commission shall consider the petition at the Regular Commission Staff Conference as scheduled and, thereafter, issue an order on the application within 30 days after the application is filed, or as near after the 30th days as reasonably practicable. Where the Commission deems issuance of an order on the application within 30 days is impossible, the Commission may issue a notice of decision within 30 days after the application is filed and subsequently issue a final order in the matter.

(l) CPRE Program Power Purchase Agreement Requirements

(1) Prior to holding a CPRE RFP Solicitation, and on or before the date set by Commission order, the Independent Administrator shall post the pro forma contract to be utilized during the CPRE RFP Solicitation on the IA Website to inform market participants of terms and conditions of the competitive solicitation. The electric public utility shall also file the pro forma contract with the Commission and identify any material changes to the pro forma contract terms and conditions from the contract used in the electric public utility's most recent CPRE RFP Solicitation.

(2) Each electric public utility shall include appropriate language in all pro forma contracts (i) providing the procuring electric public utility rights to dispatch, operate, and control the solicited renewable energy facilities in the same manner as the utility's own generating resources; (ii) defining limits and compensation for resource dispatch and curtailments; (iii) defining environmental and renewable energy attributes to include all attributes that would be created by renewable energy facilities owned by the electric public utility; and (iv) prohibiting the seller from claiming or otherwise remarketing the environmental and renewable energy attributes, including the renewable energy certificates being procured by the electric

public utility under power purchase agreements entered into under the CPRE Program. An electric public utility may propose redefining its rights to dispatch, operate, and control solicited renewable energy facilities, including defining limits and compensation for resource dispatch and curtailments, in pro forma contracts to be offered in future CPRE RFP Solicitations. In addition, an electric public utility may, within a single CPRE RFP Solicitation, propose multiple pro forma contracts that offer different rights to dispatch, operate, and control renewable energy facilities.

(3) No later than 30 days after an electric public utility executes a power purchase agreement pursuant to a CPRE RFP Solicitation, the public utility shall file the power purchase agreement with the Commission. If the power purchase agreement is with an Affiliate, the electric public utility shall file the power purchase agreement with the Commission pursuant to G.S. 62-153(a).

(4) Upon expiration of the term of a power purchase agreement procured pursuant to a CPRE RFP Solicitation, a renewable energy facility owner, other than the electric public utility, may enter into a new contract with the electric public utility pursuant to G.S. 62-156 or obtain a new contract based on an updated market based mechanism, as determined by the Commission pursuant to G.S. 62-110.8(a). If market-based authorized revenue for a generating facility owned by the electric public utility and procured pursuant to this Rule was initially determined by the Commission to be in the public interest, then the electric public utility shall similarly be permitted to continue to receive authorized revenue based on an updated market based mechanism, as determined by the Commission pursuant to G.S. 62-110.8(a). Any market based rate for either utility owned or non-utility owned facilities shall not exceed the electric public utility's avoided cost rate established pursuant to G.S. 62-156. If the electric public utility's initial proposal includes assumptions about pricing after the initial term, such information shall be made available to the Independent Administrator and all participants.

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The Appendix to Chapter 8 of the Commission's Rules is amended by adding the following:

PUBLIC NOTICE OF FILING OF PRELIMINARY PLANS TO MAKE APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-__, SUB ___

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of (Electric Public Utility) for a Certificate of Public Convenience and Necessity to Construct a (Nameplate Generating Capacity (Renewable Resource Fuel Source) Electric Generating Facility in (County Name) County, North Carolina	)	PUBLIC NOTICE

NOTICE IS HEREBY GIVEN that on (DATE), (ELECTRIC PUBLIC UTILITY), filed a letter in this docket giving notice of its intent to file an application on or after (DATE), for a certificate of public convenience and necessity (CPCN) to construct a (NAMEPLATE GENERATING CAPACITY) (RENEWABLE RESOURCE FUEL SOURCE) located at (E911 ADDRESS, IF AVAILABLE; LOCATION DESCRIPTION, IF E911 ADDRESS IS NOT AVAILABLE) in (COUNTY NAME) County, North Carolina. (ELECTRIC PUBLIC UTILITY) will apply for this certificate under the procedure for expedited review of a CPCN for a facility that is owned by an electric public utility and participating in the Competitive Procurement of Renewable Energy Program established pursuant to G.S. 62-110.8.

The North Carolina Utilities Commission anticipates considering this matter at the Regular Commission Staff Conference scheduled for (DATE OF 3rd MONDAY FOLLOWING FILING OF APPLICATION) to be held at 10:00 a.m., in the Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina.

Details of the application, once filed, 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 27699-4325 or on the Commission's website at www.ncuc.net.

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Persons desiring to be heard with respect to the application may file a statement with the Commission and should include in such statement any information that they wish to be considered by the Commission in connection with the application. If significant complaint(s) are filed with the Commission prior to the Regular Commission Staff Conference on (DATE OF 3rd MONDAY FOLLOWING FILING OF APPLICATION), the Commission will schedule this matter for hearing. Such statements will be included in the Commission's official files; however, any such written statements are not evidence unless those persons appear at a public hearing and testify concerning the information contained in their written statements. Such statements should reference Docket No. E-__, Sub ____ and should be addressed to Chief Clerk, North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, NC 27699-4325.

Statements may also be directed to Christopher J. Ayers, Executive Director, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326 or to The Honorable Josh Stein, Attorney General of North Carolina, 9001 Mail Service Center, Raleigh, North Carolina 27699-9001.

PUBLISHED PURSUANT TO COMMISSION RULE R8-71(k).

NOTE TO PRINTER: Advertising cost shall be paid by (Electric Public Utility). It is required that an Affidavit of Publication be filed with the Commission by (Electric Public Utility).

DOCKET NO. E-100, SUB 151

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Proceeding to Select the Independent	)	ORDER ESTABLISHING
Administrator of the CPRE Program	)	PROCEEDING TO SELECT THE
	)	INDEPENDENT ADMINISTRATOR
	)	OF THE CPRE PROGRAM

BY THE COMMISSION: On November 6, 2017, in Docket No. E-100, Sub 150, the Commission issued an Order adopting Commission Rule R8-71. Commission Rule R8-71 provides for the implementation of G.S. 62-110.8 and for Commission oversight of the Competitive Procurement of Renewable Energy Program (CPRE Program). Subsection G.S. 62-110.8(d) requires that the CPRE Program(s) be independently administered by a third-party entity to be approved by the Commission.

On November 3, 2017, in Docket No. E-100, Sub 150, Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP) (together, Duke) filed an update on its informal stakeholder process and a draft of its CPRE Program guidelines. Among other things, Duke indicated their intent to jointly file a proposed CPRE Program with the Commission on or before November 27, 2017, consistent with the requirements of Section 2(c) of S.L. 2017-192.

Pursuant to Commission Rule R8-71(d)(1), in advance of the filing of Duke's proposed CPRE Program on November 27, 2017, the Commission shall invite and consider comments and recommendations from the electric public utilities, the Public Staff, and other interested persons, including market participants, regarding the selection of the Independent Administrator.

Based upon the foregoing, and consistent with the provisions of Commission Rule R8-71(d), the Commission finds good cause to establish this proceeding to select the Independent Administrator of the CPRE Program. To initiate this process, the Commission invites comments and recommendations from Duke, the Public Staff, and other interested persons, including the CPRE Program's market participants. The Commission further finds good cause to make parties to this proceeding the parties in Docket No.E-100, Sub 150. Therefore, the Commission will adopt a schedule for required and permitted filings and for participation by interested persons not already a party to this proceeding. Finally, consistent with the provisions of Commission Rule R8-71(d)(3), the Commission hereby gives notice of its intent to select an Independent Administrator in advance of the first CPRE Program RFP Solicitation in this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That, on or before December 8, 2017, DEP and DEC shall identify the third-party entity or entities whom it recommends be considered for selection as the Independent Administrator of the CPRE Program by an appropriate filing in this docket. Duke's filing shall include any supporting comments that it desires the Commission to consider in selecting the Independent Administrator and any additional information that would be useful or necessary for the Public Staff and other interested parties' participation in this process;

2. That the participation of the parties of record in Docket No. E-100, Sub 150, is allowed in this proceeding without need to file petitions to intervene;

3. That other interested persons that wish to become formal parties and participate in this proceeding may file petitions to intervene pursuant to Commission Rules R1-5 and R1-19 on or before December 22, 2017;

4. That, on or before December 22, 2017, the Public Staff and other parties may file reply comments responding to Duke's recommendation and comments, including, identifying an alternative entity or entities recommended to be considered for selection as the CPRE Program Independent Administrator, if any; and

5. That, upon receipt of the parties' recommendation(s) and comments, the Commission will proceed appropriately in selecting the Independent Administrator in advance of the first CPRE RFP Solicitation.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of November, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

DOCKET NO. E-100, SUB 155

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Implement	)	ORDER ADOPTING RULE R8-72
G.S. 62-126.8	)	

BY THE COMMISSION: On August 30, 2017, the Commission issued an Order initiating this proceeding to adopt or modify the Commission's rules, as necessary, to implement the community solar energy facility program (Community Solar Program or Program) pursuant to G.S. 62-126.8, as enacted by House Bill 589 (S.L. 2017-192). In addition, that Order set an expedited schedule for receipt of comments and proposed rules to allow sufficient time to adopt final rules in advance of the January 23, 2018 deadline for the utilities to file with the Commission a plan to offer a Community Solar Program (Program Plan or Plan). See House Bill 589, Sec. 6.(d). Finally, that Order made Duke Energy Progress, LLP, and Duke Energy Carolinas, LLC (collectively, Companies), parties to this proceeding and recognized the participation of the Public Staff of the North Carolina Utilities Commission (Public Staff).

Consistent with G.S. 62-126.8(e), the Commission ordered that initial and reply comments and proposed rules or rule revisions should address the following requirements of a Community Solar Program:

(1) Establish uniform standards and processes for the community solar energy facilities that allow the electric public utility to recover reasonable interconnection costs, administrative costs, fixed costs, and variable costs associated with each community solar energy facility, including purchase expenses if a power purchase agreement is elected as the method of energy procurement by the offering utility.

(2) Be consistent with the public interest.

(3) Identify the information that must be provided to potential subscribers to ensure fair disclosure of future costs and benefits of subscriptions.

(4) Include a program implementation schedule.

(5) Identify all proposed rules and charges.

(6) Describe how the program will be promoted.

(7) Hold harmless customers of the electric public utility who do not subscribe to a community solar energy facility.

(8) Allow subscribers to have the option to own the renewable energy certificates produced by the community solar energy facility.

On or after October 12, 2017, the following parties were allowed to intervene in this proceeding: North Carolina Sustainable Energy Association (NCSEA), North Carolina Waste Awareness and Reduction Network, Inc. (NCWARN), and the Sierra Club.

On or after October 23, 2017, the Commission received consumer statements of position from The Honorable Esther E. Manheimer, Mayor of Asheville, and from The Honorable Jenn Weaver, a Commissioner of the Hillsborough Town Board. Both statements are substantively similar in that they express interest, on behalf of each individual's respective constituents, in participating in the Program. In addition, both statements encourage the Commission to adopt a rule that supports the following goals: economic benefits for subscribers, growth opportunities for the State's solar industry, increased participant access through low upfront cost, strategic placement of Community Solar Program facilities for the benefit of all utility customers, and affordable access for low-income individuals.

On October 25, 2017, NCWARN filed initial comments. On November 6, 2017, the Public Staff, the Sierra Club, the Companies, and NCSEA filed initial comments. On November 21, 2017, the Public Staff, the Sierra Club, the Companies, and NCSEA filed reply comments. No other parties filed initial or reply comments.

After carefully considering the initial and reply comments, consumer statements of position, proposed rules, and proposed rule revisions filed in this proceeding, the Commission adopts Rule R8-72, as set forth in Appendix A to this Order. In this Order, the Commission summarizes the positions of the parties, and discusses its conclusions with respect to the few disputed issues. Suggestions or comments not specifically discussed herein have been considered and decided as reflected in the final rule. In adopting Commission Rule R8-72, the Commission endeavored to give full effect to the intent of the General Assembly as expressed in the plain language of G.S. 62-126.8.

SUMMARY OF COMMENTS AND PROPOSED RULES

<u>NCWARN</u>

In its comments, NCWARN argues that the 20 megawatts (MW) of community solar capacity that the Companies each are required to provide pursuant to G.S. 62-126.8(a) is a minimum threshold, rather than a maximum limit, and that the Companies each should offer at least five times the amount of statutorily-mandated community solar capacity.

NCWARN argues that, based upon a review of existing community solar programs and model rules for such programs as published by the Interstate Renewable Energy Council (IREC), the Community Solar Program should have the following characteristics: third-party administration and participation, methodology of allocating Program benefits such that subscribers see a financial benefit, reasonable valuation of the energy produced, strategic placement of Program facilities to meet local demand and to benefit the utility grid, and third-party solar energy facility ownership coupled with attractive financing options for subscribers.

NCWARN advocates for net metering rates, and contends that the avoided cost rate mandated by G.S. 62-126.8(d) will discourage participation in the Community Solar Program. NCWARN recommends that if an avoided cost rate is used, the Companies should be required, as part of the annual avoided cost rate proceedings before the Commission, to account for all benefits of distributed solar energy, including any value added from the following: community solar placed near to load, environmental and societal values, reduced transmission cost and demand, increased grid stability and reliability, and reduced need for higher reserve margins.

NCWARN encourages a stable and transparent financial benefit to subscribers, and takes the position that the avoided cost rates initially offered to subscribers should be subject only to increase, but not to decrease, consistent with the avoided cost rates set by the Commission. NCWARN suggests that subscription fees payable in installments over time would make the Community Solar Program more accessible to low- and moderate-income subscribers. In addition, NCWARN argues that the Community Solar Program should include both a low-income set aside and on-bill financing for subscribers. NCWARN encourages the Companies to integrate the Community Solar Program with energy efficiency and other utility programs to help reduce customers' overall electricity usage.

Finally, NCWARN encourages the Commission to consider several resources and reference materials in formulating rules for the Community Solar Program.

PUBLIC STAFF

In its filings, the Public Staff states that the Community Solar Program should be designed such that a subscription offsets the subscriber's on-site electricity use, and that the costs and benefits associated therewith are proportionately divided among subscribers. To that end, the Public Staff recommends that the Companies should include as part of their Program Plan a standard contract for subscriber payments, made as either a one-time upfront or installment-over-time basis, in exchange for a credit on the subscriber's bill in the amount of the avoided cost rate. The Public Staff recognizes that subscription payments and upfront costs to subscribers may be high as a result of the statutory mandate to avoid cross-subsidization of Program costs with non-subscribing customers. The Public Staff stresses that, consistent with the public interest and G.S. 62-126.8(e)(7), subscription payments alone must be sufficient to economically sustain the Program. If the costs of the Program exceed the revenue generated by its subscriptions, the Public Staff states that Program implementation could, and potentially should, be delayed until such time as it becomes commercially viable. The Public Staff does, however, recommend that the Commission require the utilities to file annually a report summarizing the status of the Community Solar Program implementation, including whether the plan has been modified or delayed and the reasons for any such modification or delay.

The Public staff recommends that the Commission adopt a rule containing a list of disclosures that the offering utilities should be required to provide to subscribers, separate from and in addition to the disclosures they must file as part of their Program Plans. The Public staff argues that, at a minimum, the utilities should be required to disclose to each subscriber: all recurring and non-recurring charges to be borne by the subscriber throughout the life of the Program facility, all applicable Commission rules, and the terms and conditions of early termination of a subscription. Should the utilities use door-to-door agents to promote the Community Solar Program, the Public Staff recommends that the Commission adopt a consumer protection rule to require that employees or agents of the Companies properly identify themselves and provide accurate and complete verbal representations to customers regarding the Community Solar Program. The Public Staff also encourages the Commission to use as a resource the rule requiring certain disclosures adopted as part of Maryland's community solar pilot program.

The Public Staff further recommends that the Commission adopt a rule that would require a utility to allow a subscriber to elect one of the following options with respect to the renewable energy certificates (RECs) produced by each Community Solar Program facility: the utility will issue to the subscriber a proportionate share of the RECs produced from the facility, the utility will retire the RECs that otherwise would have been issued to the subscriber, or the subscriber will sell his or her interest in the RECs that he or she otherwise would have been issued in exchange for a proportionate reduction in upfront or subscription Program costs.

The Public Staff states that it reviewed all initial comments and proposed rules in this proceeding. The Public Staff does not object to either of the proposed rules submitted by the Companies and the Sierra Club, but has concerns about the Sierra Club's inclusion in its proposed rule of a dispute resolution provision. The Public Staff notes that there presently exists an established consumer complaint process over which the Commission has jurisdiction. As such, the Public Staff contends that the dispute resolution provision recommended by the Sierra Club is unnecessary.

SIERRA CLUB

In its initial and reply comments, the Sierra Club states that many community solar programs nationwide include financing mechanisms and incentives through which low- to moderate-income customers can participate. Many community solar programs also allow for a program duration of 20-25 years, or longer, to allow program costs to be spread over time. The Sierra Club stresses the importance of minimizing Program costs and maximizing Program benefits for subscribers through on-bill credits, strategic placement of facilities, and flexible participation terms. The Sierra Club also notes the potential benefits that could result from partnering with third parties to build facilities or to administer the Community Solar Program.

The Sierra Club contends that community solar programs elsewhere have been successful in part due to low upfront costs to subscribers, including one such program that requires a reimbursable, one-time deposit of $50.00 for a subscription ranging from 1 kilowatt (kW) to 15 kW of community solar energy capacity. Other community solar programs, argue the Sierra Club, have been successful because they offer flexible payment options, including a monthly subscription or installment plan. The Sierra Club uses these examples in support of its position that the Commission should require the Companies to include in their Program Plan a participation option with no or minimal upfront costs to subscribers. The Sierra Club argues that if upfront costs are unavoidable, the offering utilities should have to describe and justify those costs, and forecast to the Commission whether and how the costs and payment options available to potential subscribers will impact Program participation. The Sierra Club strongly encourages that the utilities be required to provide flexible financing options, including "pay-as-you-go" on-bill financing and installment payment plans. Regardless of whether the Community Solar Program will ultimately include upfront costs, the Sierra Club states that the offering utilities should include in their Plans the anticipated costs and benefits, both economic and environmental, to subscribers.

The Sierra Club further recommends that the offering utilities should compare the costs of self-building facilities with the costs of entering into power purchase agreements for facilities to be operated and managed by a third-party developer. Similarly, the Sierra Club posits that the offering utilities should evaluate whether to retain a third party to administer and promote the Program.

To encourage low- to moderate-income subscriber participation, the Sierra Club suggests that the Commission consider adopting a rule requiring a carve-out or set-aside to ensure that some portion of the Community Solar Program, or some portion of the subscriptions offered by each Program facility, be accessible to low- to moderate-income customers. Additionally, the Sierra Club contends that small subscription size options, such as one panel or 200 watts, can help increase and enable participation by low- to moderate-income customers.

The Sierra Club argues that the Commission should ensure that Program subscriptions are both portable and transferable. In support of this position, the Sierra Club states that these program features are consistently present in successful community solar programs elsewhere. To be sufficiently portable, the Sierra Club states that a subscriber moving within the location requirements specified in G.S. 62-126.8(c) should be able to retain his or her subscription. If a subscriber moves outside of the offering utility's service area or is otherwise unable to continue participating in the Community Solar Program, however, the Sierra Club argues that there should be an option for terminating a subscription without penalty or undue hardship to the subscriber. The Sierra Club suggests that in order to accomplish this goal, a subscriber should be allowed to transfer his or her subscription to another utility customer, to the utility itself, or to any third-party entity administering the Program on behalf of the offering utility.

The Sierra Club encourages the Commission to require the offering utilities to include a plan for complying with the location and generation limitations imposed by G.S. 62-126.8(b) and (c). Additionally, the Sierra Club states that the offering utilities should be required to identify any other criteria to be used in soliciting and selecting facility locations. The Sierra Club recommends that facilities should be sited at locations that will provide Program cost savings and grid benefits, such as siting close to load. In addition, the Sierra Club suggests that facilities should be visible and close to communities whose residents are interested in participating in the Program. Similarly, the Sierra Club suggests that the offering utilities should collaborate with communities to identify low-cost siting options. The Sierra Club encourages on-site rooftop facilities to avoid land-use and other environmental impacts sometimes associated with ground-mounted facilities. Similarly, the Sierra Club states that Program facilities also should be considered for siting on brownfields or other locations that have suffered environmental impacts from fossil fuel generation.

The Sierra Club encourages the Commission to consider several resources in promulgating rules for the Community Solar Program, including low- to moderate-income solar policy guides and principles of community engagement in developing and promoting low- to moderate-income participation in other community solar programs. The Sierra Club argues that the Commission should adopt a rule that mandates a public hearing to be held as part of the review process of the offering utilities' proposed Program Plans. In addition to its comments, the Sierra Club also submitted a proposed rule incorporating requirements from House Bill 589 and relevant provisions from IREC's Model Rules for Shared Renewable Energy Programs.

Because the Companies indicate that they intend to pursue a Program implementation schedule in stages, the Sierra Club argues that the Companies should be required to include in their Program Plan sufficient cost information and analysis supporting the economics of gradual Program implementation, including any reasonable alternatives to a gradual roll-out schedule. The Sierra Club argues that regular reporting, more often than the single report recommended by the Companies, is necessary to hold the Companies accountable for making progress toward the statutory mandate of 20 MW of community solar capacity. The Sierra Club agrees with NCSEA that the Companies should be required to obtain Commission approval before closing or suspending a Commission-approved Community Solar Program. Both the Sierra Club and NCSEA recommend that the Commission direct the Companies to clarify in their Program Plans any and all specific cost recovery mechanisms the Companies intend to seek. The Sierra Club reiterates its suggestion that the Commission adopt a rule requiring the offering utilities to include specific promotional plans aimed at making the Community Solar Program more accessible to low- to moderate-income participants.

The Sierra Club recommends that the Commission decline to adopt the Companies' proposed rule defining "avoided cost rate" on the grounds that there is uncertainty regarding when and how the avoided cost rate would be determined in the context of Program subscriptions. Furthermore, the Sierra Club recommends that the Commission decline to adopt a rule defining "avoided cost rate," but rather should require the offering utilities to submit the avoided cost rates and methodology intended to be used as part of the Companies' proposed Program Plans.

The Sierra Club recommends that the Commission use the definition of "nameplate capacity" found in North Carolina interconnection standards, as opposed to the definition contained in the Companies' proposed rule. See Order Approving Revised Interconnection Standard, Docket No. E-100, Sub 101 (May 15, 2015). The Sierra Club agrees with the Public Staff that the offering utilities should include as part of their proposed Program Plans a standard contract for subscriber fees paid in exchange for on-bill credits. The Sierra Club agrees with NCSEA's recommendation that several payment options should be provided to subscribers, including a payment-over-time option, installment payment option, and financing for any upfront fee charged to subscribers.

NCSEA

In its initial and reply comments, NCSEA states that the Commission is tasked with rectifying the offering utilities' cost recovery ability set forth in G.S. 62-126.8(e)(1) with the arguably conflicting provisions of House Bill 589, namely, that the Community Solar Program should be in the public interest and that non-subscribing customers must be held harmless. NCSEA encourages the Commission to consider the community solar report to which NCSEA is a signatory in promulgating rules governing the Community Solar Program.

NCSEA recommends that the Commission should ensure through rulemaking that the following three participation models, which NCSEA contends have been successful in other jurisdictions, are made available to North Carolina customers: an upfront participation fee, an upfront participation fee financed across a specified timeframe, and a set monthly participation fee. NCSEA also recommends that the Commission should ensure the transferability of subscriptions and implement certain reporting requirements for the offering utilities.

NCSEA encourages the Commission to make clear in its rules that customers may retain their existing rate tariff when they opt to participate in the Community Solar Program. In support of this position, NCSEA cites to the Commission's approval of the NC GreenPower Program, which allowed participation in conjunction with any rate tariffs. See Order Approving Revised Program Plans and Utility Tariffs, Docket No. E-100, Sub 90 (June 12, 2008). Finally, NCSEA recommends that the Commission adopt in its rules a provision for a utility to apply for a waiver of the subscriber location requirement set forth in G.S. 62-126.8(c).

In its reply comments, NCSEA notes that relatively few issues are in dispute between the parties. NCSEA supports the Sierra Club's proposed rule, and would support the Companies' Proposed Rule if modified in a manner consistent with NCSEA's reply comments. NCSEA suggests that the Commission should direct the offering utilities to include in their proposed Program Plans cost information and justification supporting whether to use a third-party administrator for the Community Solar Program. NCSEA highlights the Companies' intent to recover through the fuel rider costs associated with the procurement of any energy through one or more power purchase agreements. Although the Companies' proposed rule makes no reference to this method of cost recovery, NCSEA notes that the Companies did not propose in its comments any changes to Commission Rule R8-55. As such, NCSEA recommends that the Commission direct the Companies to clarify in its Program Plan any and all specific cost recovery mechanisms the Companies intend to seek.

NCSEA notes that neither the Companies nor the Public Staff address in their initial comments proposals for encouraging participation of low- to moderate-income customers. NCSEA argues that it is in the public interest for the Commission to adopt rules that provide access to participation in the Community Solar Program for such customers. NCSEA further recommends that the Commission require the offering utilities to specify whether they intend to prescribe a particular rate tariff schedule to Program subscribers.

NCSEA notes that the Companies' proposed rule recommends that a single report be required by the rule, while the Sierra Club recommends semi-annual reporting. NCSEA supports the Sierra Club's recommendation that the offering utilities be required to file reports every six months. NCSEA does not oppose the Companies' recommendation to use the most recently approved biennial avoided cost rates, but recommends that the benefits of community solar to non-subscribing customers should be accounted for in the subscription fee analysis. NCSEA further recommends that the Commission adopt consumer protection rules if the offering utilities plan to promote the Program through door-to-door agents. NCSEA is opposed to the Companies' recommendation that they be allowed to suspend or close a Commission-approved Program without first obtaining Commission approval.

THE COMPANIES

In their filings, the Companies propose a rule that would provide for a gradual roll-out of their Community Solar Program in stages or "tranches" less than 20 MW at a time, likely 1-2 MW in size, until the 20 MW cap is achieved in each offering utility's service territory. The Companies would then be allowed to file subsequent Program Plans, potentially modifying the procedures and procurement methods for subsequent stages. In addition to reporting proposed modifications to its approved Program Plan, the Companies propose filing a single report on the status of the Community Solar Program not later than one year after the Commission approves each offering utility's Plan. The Companies' proposed rule would allow the offering utilities to recover through subscription fees the administrative costs of the Community Solar Program, as well as the cost of any power purchase agreements with third-party facilities in excess of the offering utility's avoided costs. If the offering utility chooses to build and own its own facility, rather than to procure use of a facility through a third-party power purchase agreement, the offering utility will file with the Commission a revised Program Plan that outlines the proposed recovery of costs under utility ownership.

The Companies' proposed rule would require the offering utilities to include as part of their Program Plan the following: the process for Program participation, procedures for complying with the requirement that subscribers shall have the option to own the RECs produced by a Program facility, proposed Program implementation schedule, the methodology for determining the subscription fee, and a discussion of how the offering utilities will communicate with and inform potential subscribers about the costs, rate schedules, and Program benefits. The Companies' proposed rule would require the offering utilities to file with the Commission for its review and approval the tariff, pro forma contract, or any online offer of terms and conditions that would be used to engage subscriptions.

The Companies oppose NCWARN's suggestion that the offering utilities add 200 MW of community solar generation annually over the next three years, with additional amounts added thereafter. The Companies counter this position, stating that the statutory language allows the eventual, incremental implementation of the 20 MW-per-utility mandate set forth in G.S. 62-126.8(a). In response to NCWARN's recommendation that the offering utilities use a third-party administrator for the Community Solar Program, the Companies state that G.S. 62-126.8 does not include such a requirement. The Companies further state that while it has not excluded the possibility of retaining a third-party administrator for the Community Solar Program, they still are reviewing whether the use of a third-party administrator could result in increased costs that would have to be borne by subscribers. The Companies reiterate the requirement in G.S. 62-126.8 that the implementation and administrative costs associated with the Community Solar Program must be borne solely by subscribers such that the expenses are not cross-subsidized among non-participating customers. The Companies state that in response to NCWARN's request that subscriber credits be stable and transparent, the Companies' proposal involves levelized on-bill crediting across the term of the Program subscription contract. In response to NCWARN's suggestion that the avoided cost payment to subscribers should reflect tangible and intangible benefits of distributed solar energy across customer classes, the Companies state that their proposed rule defines the avoided cost rates as the electric public utility's calculation of its avoided costs based on the methodology most recently approved or established by the Commission as of the date that a subscription commences.

The Companies also include in their comments a proposed modification to Commission Rule R8-65 to reflect potential electric utility ownership of facilities used for the Program.

The Companies generally agree with the process for review proposed by the Sierra Club, but oppose the Sierra Club's recommendation that the Commission should preemptively require a public hearing on the Program Plans. The Companies contend that a mandatory public hearing exceeds the scope of the requirements set forth in G.S. 62-126.8, and that such a provision would be unnecessary given the Commission's existing authority and discretion to order a hearing when necessary. Similarly, while the Companies do not object to the Sierra Club's recommendation for a dispute resolution provision, the Companies contend that such a provision may be unnecessary because it mirrors the Commission's current practice for adjudicating consumer complaints against public utilities.

In response to the Public Staff's recommendation that the Companies include a standard contract in their proposed Program Plans, the Companies state that their proposed rule would require the Companies to file a tariff, a standard contract, a statement of terms and conditions, or some combination of any or all of those. The Companies do not object to including the types of information requested by NCSEA and the Sierra Club in its report, but contend that semiannual reports are unnecessary because the Companies' proposed rule would allow the Commission or the Public Staff sufficient opportunity to request subsequent reports in their discretion. The Companies state that the adoption of consumer protection rules to govern door-to-door marketing and promotion is unnecessary because the Companies do not intend to use this method of Community Solar Program promotion, and that this issue may instead be addressed in the future, as necessary, if the Companies intend to change their promotional methods to include door-to-door agents.

The Companies state that G.S. 62-126.8 does not require a low- to moderate-income component to the Community Solar Program, but that the Companies' proposed rule allowing subscription sizes as low as 200 watts will enable a wider range of customers to subscribe. The Companies argue that any additional low- to moderate-income components to the Community Solar Program are impossible due to the statutory prohibition against cross-subsidization of Program costs. Accordingly, the Companies argue that it would be inappropriate for the Commission to include a low- to moderate-income component in its rule. While the Companies state that they do not object to multiple subscriber payment options, including a single upfront payment or a monthly subscription fee, the Companies oppose the recommendation that the Commission direct them to include an on-bill financing option due to increased overhead costs resulting from credit checks and collections efforts. In response to comments regarding portability and transferability of subscriptions, the Companies suggest that the offering utilities be required to submit in their proposed Program Plans information about the transferability of subscriptions. The Companies oppose, on the basis that it would increase Program costs and complexity, the recommendation that it be required to include, as part of their Program Plans, a plan for local community engagement or other siting requirements.

The Companies disagree with the Public Staff's recommendation that the Commission require the companies to offer subscribers the option to sell their rights to RECs in exchange for a reduction in price of a subscription to the Community Solar Program. The Companies state that Duke Energy Progress, LLP currently has no need for solar RECs, and that the purchase thereof would thus exceed its compliance requirements. Furthermore, the Companies contend that it is unclear whether they could recover the cost of RECs they could be forced to purchase if a subscriber were to elect this option, due to the prohibition against cross-subsidization of Program costs with non-subscribing customers.

DISCUSSION AND CONCLUSIONS

Based upon the foregoing and the entire record in this proceeding, the Commission adopts Commission Rule R8-72, as set forth in Appendix A to this Order. The Commission carefully considered all comments, reply comments, proposed rules, and revised proposed rules filed in this proceeding. The parties' filings were helpful to the Commission in its rulemaking to implement G.S. 62-126.8.

The parties filed in this proceeding two versions of a proposed rule: one advanced by the Companies and the other advanced by the Sierra Club. In many respects, the two versions are substantively similar, and portions of both versions are supported by all parties to this proceeding. The Commission discusses below its conclusions related to the relatively few, most salient issues in dispute by the parties to this proceeding.

ISSUES NOT ADDRESSED IN RULE R8-72

As an initial matter, the Commission first determines that Rule R8-72 primarily should be a rule governing the filing requirements of the Community Solar Program. Thus, the Commission reserves judgment on a number of issues proposed and discussed by the parties in this proceeding until the Companies file proposed Program Plans, at which time those issues will become ripe for Commission review and decision. As discussed below, however, the Commission determines that it is appropriate to require the Companies to address many of these issues in their proposed Program Plans. Intervenors in this proceeding and any other interested person are encouraged to submit comments during the comment period following the filing of the Companies' proposed Program Plans, as set forth in Rule R8-72(e)(2) adopted by this Order.

The Commission also declines to address in Rule R8-72 the position taken by a number of intervenors that the 20 MW of community solar energy capacity, as required by G.S. 62-126.8, is a minimum threshold rather than a maximum limit. The Commission regulates the offering utilities only to the extent it has been delegated the requisite statutory authority by the General Assembly. The applicable statute states, in relevant part, that each "offering utility shall make its community solar energy facility program available on a first-come, first-served basis until the total nameplate generating capacity of those facilities equals 20 megawatts (MW)." G.S. 62-126.8(a) (emphasis added). Although G.S. 126.8(a) mandates only that the offering utilities make available for subscription a Community Solar Program up to 20 MW of capacity, the offering utilities at any time may elect to purchase or procure additional solar energy beyond the 20 MW required to satisfy the Program requirements. However, any decision to approve more than the 20 MW of statutorily-mandated Program capacity, subject to applicable statutes and Commission rules, would be made at that time.

The Commission further determines that the Companies' proposed revisions to Commission Rule R8-65 are more appropriately addressed in the Commission's existing rulemaking dockets initiated for the purpose of administratively amending Commission Rules to be consistent with the changes enacted by the passing of HB 589. See Order Giving Notice of Implementation of New Fees and Administrative Changes, Docket No. E-100, Subs 113, 121, and 134 (August 3, 2017). In that Order, the Commission announced, in part, its intent to amend Commission Rule R8-65 to be consistent with the changes enacted by the passing of HB 589. Rather than implementing piecemeal administrative changes to Rule R8-65 in separate dockets, the Commission will address this issue in that proceeding.

ISSUES ADDRESSED IN RULE R8-72

The two versions of the rule proposed by the parties are generally consistent with the formatting and structure of other rules in Chapter 8 of the Commission's Rules; therefore, the Commission adopts the basic structure of Rule R8-72 as proposed by the parties, with modifications tending to consolidate the filing requirements, streamline the text of the rule, and conform to the conventions of other Commission Rules. The Commission now addresses each section of Rule R8-72, as adopted herein.

1. Purpose (section (a) of the parties' proposed rules):

The parties agree that the purpose of the rule is to implement the Community Solar Program created by the enactment of G.S. 62-126.8. Reflecting the Commission's determination that Rule R8-72 primarily should be a rule governing the Program Plan filing and reporting requirements, the Commission adopts language reflective of the Sierra Club's proposed section (a), which provides that the Commission also should provide guidance related to permitted and required filings when an offering utility proposes a Program Plan. Therefore, the Commission adopts Commission Rule R8-72(a), as set forth in Appendix A, attached hereto.

2. Definitions (section (b) of the parties' proposed rules):

Both parties propose definitions to be used in the context of their proposed rules. The Sierra Club's proposed rule incorporates the terms and definitions set forth in G.S. 62-126.3, except that it also proposes one additional definition for "participant," which is not already defined by statute. The Companies, on the other hand, propose several definitions that already are defined in Chapter 62 of the North Carolina General Statutes, and suggest that the definitions proposed in the rule should control if a term is defined both in statute and in the proposed rule. Most of the Companies' proposed definitions are largely undisputed by the parties, with the exception of two proposed terms: "nameplate capacity" and "avoided cost rate."

The parties suggest in their comments and proposed rules three different approaches for defining "avoided cost rate." NCWARN advocates for "net metering rates," and contends that the avoided cost rate mandated by G.S. 62-126.8(d) will discourage participation in the Community Solar Program. In addition, NCWARN recommends that an avoided cost rate used in the Program should reflect any value added to non-subscribing customers of solar energy distributed by the Program. The Companies' proposed rule, on the other hand, includes a definition directly tying the proposed "avoided cost rate" to the Commission's biennial avoided cost proceedings. The Sierra Club objects to the Companies' proposed definition of "avoided cost rate" on the grounds that the term "avoided cost," as used in G.S. 62-126.8(d), allows more flexibility than the strict definition the Companies seek. The Sierra Club further objects on the grounds that intervenors to this proceeding have not had an opportunity to oppose the avoided cost rate and methodology to be used by the Companies in administering their respective Programs. The Sierra Club, therefore, suggests that the Commission decline to adopt the Companies' proposed definition for "avoided cost rate," and instead adopt a rule that requires the offering utilities to submit in their Plans the proposed avoided cost rates and methodology for determining said rates. The Commission agrees with the Sierra Club that this is a decision that goes more toward content of the Program itself, rather than a filing requirement for the proposed Program Plans, and should be left for consideration by the Commission during the review process of the Plans. Therefore, the Commission declines to adopt in Rule R8-72 a definition for "avoided cost rate," and instead adopts Commission Rule R8-72(c)(1)(v), which requires each offering utility to submit as part of its proposed Plan the methodology for determining the avoided cost rate at which subscribers will receive bill credits.

The Companies advance in their proposed rule a definition for "nameplate capacity," but did not include an explanation or justification for its proposed definition. The Sierra Club objects to the Companies' proposed definition for "nameplate capacity" on this basis, and suggests use of the definition for "nameplate capacity" found in the North Carolina interconnection standards. See Order Approving Revised Interconnection Standard, Docket No. E-100, Sub 101 (May 15, 2015). The Commission finds that this also is a decision that goes more toward content of the Program itself, rather than a filing requirement for the proposed Program Plans, and should be left for consideration by the Commission during the review process of the Plans. Therefore, the Commission declines to adopt in Rule R8-72 a definition for "nameplate capacity," and instead adopts Commission Rule R8-72(c)(1)(vi), which requires each offering utility to submit as part of its proposed Plan the methodology for determining the nameplate capacity of a Program facility.

In addition, the Commission finds it appropriate to ensure consistent terminology is used in Rule R8-72 and the proposed Plan filings when describing a retail customer who subscribes to the Program. The Sierra Club proposes the term "participant," while the Companies propose the term "subscriber." The definitions of the proposed terms are not substantively different. In order to ensure consistency and to minimize potential confusion,, the Commission adopts Rule R8-72(b)(5), which contains a definition for "subscriber" to the Program.

3. Filing, reporting, and additional Program requirements (sections (c), (e), and (f) of the Companies' proposed rule; sections (c), (d), and (f) of the Sierra Club's proposed rule):

The Public Staff suggests, and several intervenors agree, that the Commission should adopt a rule requiring the Companies to establish a standard contract for subscriber payments in exchange for a credit on the subscriber's bill. In their reply comments, the Companies state that they include in their proposed rule the option to file as part of the Program Plan "a tariff, standard contract, statement of terms and conditions, or some combination of any or all of these." The Commission agrees with the Public Staff and intervenors that the offering utilities should be required to file as part of their Program Plans a standard contract, or its equivalent, governing the terms and conditions of a Program subscription. The Commission determines the Companies' proposed verbiage to be adequate to satisfy the oversight requirement of G.S. 62-126.8. Therefore, the Commission adopts Rule R8-72(c)(1)(viii), which requires the offering utilities to include in their proposed Plans a tariff, standard contract, statement of terms and conditions, or some combination of any or all of these, containing the following: all terms and conditions regarding costs, risks, and benefits to the subscriber, an itemized list of any one-time and ongoing subscription fees, an explanation of RECs, and when and how the subscriber will receive notifications regarding project status and performance.

The Companies' proposed rule would require them to file a single report with the Commission not later than one year after the initial Plan is approved. Thereafter, the Companies only would be required to file a report at the direction of the Commission or the Public Staff. The Sierra Club and other intervenors, however, propose a semi-annual reporting requirement. The Commission agrees with the Sierra Club that more regular reporting is necessary to satisfy the oversight requirement mandated by G.S. 62-126.8. The primary goal of these required filings is to keep the Commission, the Public Staff, the Companies' customers, and other interested persons abreast of developments in the Community Solar Program. The Commission disagrees, however, that semiannual reporting is necessary to ensure adequate oversight of Program implementation. Therefore, the Commission adopts Rule R8-72(c)(2), which provides that the offering utility shall file annually with the Commission a report that includes updates on Program implementation progress, marketing efforts, the number of participants subscribed, and capacity subscribed. Upon receipt, the Commission shall decide whether to approve the annual report.

The Companies' proposed rule would allow each offering utility to suspend or close, by its own unilateral decision, an approved Program. The Sierra Club objects to this provision on the grounds that it would be contrary to the Commission oversight mandated by statute. The Sierra Club alternatively proposes that the offering utilities should be required to explain the reasons for wishing to suspend or close an approved Program and to first obtain Commission approval before discontinuing an approved Program. The Commission agrees with the Sierra Club that it would be inconsistent with the legislative intent and Commission oversight required by G.S. 62-126.8 if an offering utility were allowed to unilaterally close or suspend an approved Plan without first justifying its proposed action and obtaining Commission approval. Furthermore, the Commission notes that the Community Solar Program is not a permissive pilot program suggested by the General Assembly; rather, it is a statutory mandate. Therefore, the Commission adopts Rule R8-72(c)(4), which requires an offering utility to obtain Commission approval before implementing any amendment or revision to an approved Program Plan, including whether to delay, suspend, or close a Program to new subscribers.

As discussed earlier in this section, the Commission determines that Rule R8-72 primarily should govern the filing, reporting, and Program requirements of the Community Solar Program. Therefore, the Commission adopts Rule R8-72(c) and (d) as a consolidation of the parties' recommended filing, reporting, and Program requirements, which are included in sections (c), (e), and (f) of the Companies' proposed rule, and sections (c), (d), and (f) of the Sierra Club's proposed rule.

4. Review of Program Plans (section (d) of the Companies' proposed rule; section (e) of the Sierra Club's proposed rule):

Both proposed rules incorporate a section describing the Commission's procedure to review the Companies' forthcoming proposed Plans. The Commission determines that inclusion of such a section is consistent with the construct of other Commission rules in Chapter 8, and is appropriate for inclusion in Rule R8-72. Therefore, the Commission adopts Rule R8-72(e), which sets out the Commission's procedure upon receipt of proposed Plan filings.

The Sierra Club suggests as part of its proposed rule that the Commission require at least one public hearing to allow interested persons to comment on the Companies' proposed Program Plans. The Companies disagree with this suggestion on the grounds that public input and comment will be solicited through other means and that a mandatory hearing is unnecessary because the Commission has the discretion to order a hearing if necessary to make a decision on the proposed Plans. The Commission often has public hearings as part of any number of types of dockets, and it acknowledges that public hearings provide an important means for interested persons to provide their input without the burden of intervening. However, the Commission agrees with the Companies that there will be sufficient opportunities, without a mandatory public hearing, for interested persons to provide comment. Should the Commission determine that a public hearing is needed to make a decision on the proposed Plans, it has the discretion to so order at the appropriate time. Furthermore, any party could request a hearing when responding to the Companies' proposed initial Plans or subsequent filings. The Commission's decision in this Order does not guarantee that the Commission would grant or deny such a request. While the Commission declines to adopt the public hearing mandate suggested by the Sierra Club, it has incorporated into Rule R8-72 mechanisms through which interested persons will have a meaningful opportunity to participate in the review process of the Companies' proposed Program Plans and subsequent filings.

5. Dispute resolution (section (g) of the parties' proposed rules):

The Sierra Club proposes in its rule a process for dispute resolution that appears to resemble the existing practice for consumer complaints filed with the Commission against a public utility. The Companies include a similar provision in their amended proposed rule, but note that the process seems identical to current practice. The Public Staff, on the other hand, express concern that the inclusion of a dispute resolution provision is unnecessary. Any interested person, including a subscriber to the Community Solar Program, is able to seek help informally from the Public Staff and may file with the Commission a complaint against a public utility regarding billing or service disputes. See G.S. 62-73. The Commission agrees with the Public Staff that the existing complaint process is sufficient to address complaints subscribers may have regarding the Community Solar Program. However, the Commission finds value in requiring the offering utilities to inform subscribers of the complaint resolution process available to them as a means of potential recourse in the event that the offering utility has committed an actionable violation. Accordingly, the Commission declines to adopt the dispute resolution provision proposed by the Sierra Club. However, the Commission has included in Rule R8-72(c)(1)(vii) a requirement that the Companies must disclose to Program subscribers the process by which they can file a complaint with the Commission.

Based upon the foregoing and the entire record in this proceeding, the Commission adopts Rule R8-72, as set forth in Appendix A to this Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of December, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

APPENDIX A
Page 1 of 4

Commission Rule R8-72 is adopted as follows:

Rule R8-72 COMMUNITY SOLAR PROGRAM.

(a) Purpose. The purpose of this Rule is to implement the provisions of G.S. 62-126.8 as they relate to each offering utility's implementation of a Community Solar Program for the participation of retail customers.

(b) Definitions. Unless listed below, the definitions of all terms used in this Rule shall be as set forth in G.S. Chapter 62. The following terms are defined for purposes of this Rule as:
(1) "Community solar energy facility" or "facility" means a solar photovoltaic energy system that complies with the requirements set forth in G.S. 62-126.8(b) and (c), and is used to satisfy a portion of the generating capacity required by G.S. 62-126.8(a).
(2) "Community Solar Program" or "Program" means the program offered by an offering utility for the procurement of electricity by the offering utility for the purpose of providing subscribers the opportunity to share the costs and benefits associated with the generation of electricity by the facility.
(3) "Community Solar Program Plan" or "Program Plan" means the plan for implementation of the Community Solar Program, to be filed by each offering utility for the Commission's review and approval.
(4) "Solar photovoltaic energy system" means equipment and devices that have the primary purpose of collecting solar energy and generating electricity by photovoltaic effect.
(5) "Subscriber" means a retail customer of the offering utility who subscribes to one or more blocks of community solar energy facility generating capacity, and is located in the state of North Carolina and in the same county or county contiguous to the facility, unless subject to an exemption pursuant to G.S. 62-126.8(c) and Section (e)(4) of this Rule.
(6) "Subscription" means the individual block of community solar energy facility generating capacity, which represents 200 watts or more of such generating capacity but not more than 100% of each subscriber's maximum annual peak

demand of electricity at the subscriber's premises, to be purchased by a subscriber for a set term of up to twenty-five (25) years, throughout which the subscriber receives a bill credit for the subscribed amount of electricity generated by the facility.

(7) "Subscription fee" means any charge paid by a retail customer in exchange for a subscription to an approved Program.

(c) Community Solar Program Plan Filing Requirements.

(1) Each offering utility shall file, on or before January 23, 2018, an initial proposed Program Plan, which shall meet the requirements of G.S. 62-126.8(e), and shall contain the following:

(i) the standards and processes for the offering utility to recover reasonable interconnection costs, administrative costs, fixed and variable costs associated with each facility, and any other forecasted costs and intended cost recovery mechanisms;

(ii) an explanation of how non-subscribing customers of the offering utility will be held harmless from the Program, including a description of how the offering utility intends to avoid cross-subsidization of Program costs with non-subscribing customers;

(iii) a description of and justification for Program participation options available to subscribers, including a description of any available payment plans or financing options, information on the treatment of subscriptions if a subscriber moves within or outside of the offering utility's service territory, and whether and how subscriptions may be transferred from a subscriber to another customer who is eligible to participate in the Program;

(iv) the methodology for determining the subscription fee, including whether a subscriber would retain his or her existing rate tariff, and a description and justification for any proposed upfront subscription fee and the projected impact of each such fee on overall participation in the Program;

(v) the methodology for determining the avoided cost rate at which subscribers will receive bill credits;

(vi) the methodology for determining nameplate capacity of a facility;

(vii) a discussion of how the Program will be promoted, including the projected costs associated with marketing and promotion efforts, examples of communications or marketing materials to be used, and identification of information to be provided to customers, including but not necessarily limited to: an itemized list of any and all charges composing the subscription fee and the schedule upon which the charges would be due, the process by which a subscriber can file a complaint with the Commission, and all offering utility and Commission rules governing the Program;

(viii) a tariff, pro forma contract between the subscriber and the offering utility, a statement of terms and conditions, or any or all of these, that contain all terms and conditions regarding costs, risks, and benefits to the subscriber, an itemized list of any one-time and ongoing subscription fees, an explanation of renewable energy certificates, and when and how the subscriber will receive notifications regarding project status and performance;

(ix) a description of a subscriber's option to own the renewable energy certificates produced by the facility, including how this information will be distributed to subscribers;
(x) an estimate of economic costs and benefits for an average program subscriber, estimated time period for a subscriber to receive a return on investment, and a description of any quantifiable economic or environmental benefits to non-subscribing customers;
(xi) a description of siting considerations and site selection process;
(xii) a description and analysis of how the offering utility's Program design will minimize costs and maximize benefits for each subscriber;
(xiii) a description of the offering utility's intended method for the procurement of solar energy for the Program, including a cost estimate and justification for each method proposed;
(xiv) an implementation schedule for installing 20 MW of solar energy, including a cost estimate and justification for the proposed schedule; and
(xv) a description of how the Program Plan is consistent with the public interest.

(2) The offering utility shall file annually with the Commission a report that includes any proposed amendments or revisions to its existing Program Plan and updates on Program implementation progress, marketing efforts, the number of participants subscribed, and capacity subscribed.
(3) An offering utility shall provide additional updates upon request by the Public Staff, or as required by the Commission.
(4) An offering utility shall apply for and obtain Commission approval before implementing any amendment to an existing Program Plan, including whether to delay, suspend, or close a Program to new subscribers.

(d) Minimum Program requirements and procedures.
(1) The offering utility may elect to own and operate facilities to procure energy for the Program, may procure energy for the Program through power purchase agreements with qualifying "small power production facilities" as defined in 16 U.S.C. § 796, or both.
(2) Retail customers of each offering utility may voluntarily subscribe to the Program on a first-come, first-served basis in a manner consistent with any Program Plan approved by the Commission.
(3) No single subscriber shall subscribe to more than a forty percent (40%) interest in an offering utility's Program.

(4) Subscribers may subscribe to individual blocks, sized to represent 200 watts or more, of a facility's generating capacity.
(5) Subscribers are responsible to pay the subscription fee for each block of facility capacity to which they subscribe.

(6) Subscribers may purchase multiple subscriptions consistent with G.S. 62-126.8, subject to each offering utility's cap for residential, commercial, and industrial customers limited to no more than one hundred percent (100%) of the maximum annual peak demand of electricity of each subscriber at the subscriber's premises.
(7) A subscriber shall be notified of Program enrollment prior to first being billed and credited in accordance with his or her subscription.
(8) If enrollment exceeds availability, the offering utility shall add potential subscribers to a subscriber waiting list.

(e) Procedure for Review of Community Solar Program Plans.
(1) The Commission may approve, disapprove, or modify an offering utility's initial Program Plan, annual report, or any proposed amendments to an existing Program Plan.
(2) After the filing of an offering utility's Program Plan or request to amend an existing Program Plan, the Commission will issue a procedural order setting deadlines for intervention and comments, and will proceed as appropriate and in a manner consistent with this Rule and G.S. 62-126.8.
(3) The Commission, for good cause shown, may order any investigation, hearing, or required filings as it deems necessary and appropriate to address the issues raised in a Program Plan, annual report, or any proposed amendments to an existing Program Plan filed by an offering utility. The scope of any such investigation, hearing, or required filings shall be limited to such issues as identified by the Commission.
(4) To the extent the offering utility seeks an exemption of the requirement in G.S. 62-126.8(c) that subscribers must be located in the same county or county contiguous to where the facility is located, the offering utility shall file with the Commission a request for such an exemption. If the Commission determines the request is in the public interest, it shall approve the request, provided that the subscriber remains a resident of the State and that the facility is located no more than 75 miles from the county of the subscriber.
(5) The offering utility shall have the burden of proof to demonstrate that the offering utility's Program Plan, annual reports, and any proposed amendments to an existing Program Plan are reasonable and comply with the requirements in G.S. 62-126.8 and this Rule.

DOCKET NO. SP-100, SUB 32

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request for a Declaratory Ruling by	)	ORDER ON REQUEST FOR
Col. Francis X. De Luca USMCR(RET)	)	DECLARATORY RULING

BY THE COMMISSION: On May 17, 2017, Francis X. De Luca filed a petition for a declaratory ruling in the above-captioned docket. In summary, Francis De Luca requests that the Commission find that Fresh Air Energy, LLC, [*sic* Fresh Air Energy II, LLC] (Fresh Air) is a public utility pursuant to G.S. 62-3(23) for purposes of Chapter 62 of the North Carolina General Statutes. Mr. De Luca explains that he is seeking this declaration so that North Carolina will have access to information to determine the true cost of solar power and that currently North Carolina does not have access to any information from any of the new qualifying facilities, such as Fresh Air.

Mr. De Luca argues that Fresh Air meets the definition of a public utility as defined under G.S. 62-3(23) because the company will produce electricity "to or for the public for compensation," and the company does not fall within any of the statutory exemptions. Mr. De Luca also refers to Kendal Bowman's rebuttal testimony on behalf of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC (collectively Duke), in Docket No. E-100, Sub 148 (the avoided cost docket) in which she states that Duke customers will be overpaying for solar energy by as much as $1 billion due to the current long-term contract requirement and changing avoided cost rates. Mr. De Luca states that by declaring solar facilities such as Fresh Air as a public utility, utility customers may have access to information to determine the true cost of solar power to determine what costs customers should bear.

On May 18, 2017, the Commission issued an Order Requesting Comments. On June 1, 2017, Fresh Air Energy II, LLC filed comments. On June 2, 2017, the Public Staff - North Carolina Utilities Commission (Public Staff) and the North Carolina Sustainable Energy Association (NCSEA) filed comments. On June 9, 2017, Francis De Luca filed responsive comments.

In its comments, the Public Staff ultimately concludes that Fresh Air is not a public utility under Chapter 62. In its analysis, the Public Staff sets forth the definition of a public utility in G.S 62-3(23) which states in pertinent part:

> a. Public utility means a person, whether organized under the laws of this State or under the laws of any other state or country, now or hereafter owning or operating in this State equipment or facilities for:
>
> 1. Producing, generating, transmitting, delivering or furnishing electricity, piped gas, steam or any other like agency for the production of light, heat or power to or for the public for compensation; provided, however, that the term "public utility" shall not include persons who construct or operate an electric

generating facility, the primary purpose of which facility is for such person's own use and not for the primary purpose of producing electricity, heat, or steam for sale to or for the public for compensation;

....

b. The term "public utility" shall for rate-making purposes include any person producing, generating or furnishing any of the foregoing services to another person for distribution to or for the public for compensation.

c. The term "public utility" shall include all persons affiliated through stock ownership with a public utility doing business in this State as parent corporation or subsidiary corporation as defined in G.S. 55-2 to such an extent that the Commission shall find that such affiliation has an effect on the rates or services of such public utility.

The Public Staff next states that Fresh Air is a qualifying facility (QF), as that term is defined under the Public Utilities Regulatory Policies Act of 1978 (PURPA) and that the Commission has already addressed the question of whether a QF is a public utility in its February 29, 1984 Order on Request for a Declaratory Ruling in Docket No. SP-100, Sub 0 (Cogentrix case). Cogentrix sought clarification that its construction and operation of certain cogeneration facilities adjacent to textile plants for the production of steam for use in the textile plants and electricity for sale to the local public utilities did not render it a public utility. In that docket, the Commission held:

> We do not believe that subsection a [of G.S. 62-3(23)] was intended to cover the situation of a qualifying cogeneration facility under PURPA that furnishes electricity to another for distribution and sale to or for the public and has no other public utility attributes of its own. Subsection b would appear to cover such a situation; however, it defines a public utility only "for rate-making purposes," and the rates for Cogentrix are set pursuant to PURPA, not state law. Indeed, PURPA exempts qualifying facilities as described therein from state law or regulation respecting the rates of electric utilities. See 18 CFR 292.602. Thus, the Commission concludes that the generation and sale of electricity by Cogentrix and its affiliates will not be "to or for" the public so as to bring Cogentrix and its affiliates within the provisions of G.S. 62-3(23)a.

The Public Staff also sets forth its analysis of whether Fresh Air would be a public utility under North Carolina case law outlining the factors set forth in State ex rel. Utils. Comm'n v. Simpson, 295 N.C. 519, 524 (1978) (adopting a flexible definition of "the public"). The Simpson court held that "what is the "public" in any given case depends rather on the regulatory circumstances of that case." Id. The Public Staff asserts that the Court in Simpson was concerned with the State's public policy of promoting the benefits of a regulated monopoly, two of which are preventing excessive retail rates and preventing uneconomic overbuilding of capital facilities where a monopoly is more economic. The Public Staff states that Fresh Air does not have monopoly power to exercise power over pricing to retail customers, and there is no evidence of duplication of facilities that would constitute uneconomic overbuilding in this case. Lastly, the

Public Staff contends that Fresh Air's sale of electricity to DEC in no way intrudes upon DEC's utility franchise, or in other words, there is no risk that Fresh Air will sell directly to DEC's customers leaving DEC's fixed costs to be spread over a smaller customer base, the concern in Simpson.

In its comments, Fresh Air outlines similar arguments to the Public Staff with respect to the Cogentrix case which will not be reiterated here. As for the analysis under the Simpson factors, Fresh Air argues that unlike Simpson, Fresh Air will not hold itself out as willing to serve the public or any subset thereof. Fresh Air is only selling to DEC, who then sells the electricity to its customers. Fresh Air is not selling electricity to the ultimate consumer.

In further support, Fresh Air sets forth the objectives of PURPA. FERC, in Order No. 69, explained that:

> Prior to the enactment of PURPA, a cogenerator or small power producer seeking to establish interconnected operation with a utility faced three obstacles ... [one of which was] a cogenerator or small power producer which provided electricity to a utility's grid ran the risk of being considered an electric utility and thus being subjected to State and Federal regulations as an electric utility. Sections 201 and 210 of PURPA are designed to remove these obstacles.

FERC Stats. & Regs. 30,128 (1980) in Docket RM79-55, 45 Fed. Reg. 12,214 (1980). The FERC regulations expressly exempt QFs from certain federal and state laws and regulations in the interest of minimizing the regulatory burden on these facilities.

The last argument that Fresh Air advances highlights that Chapter 62 obligates entities other than public utilities to obtain a certificate of public convenience and necessity (CPCN) prior to beginning construction of a generation facility. G.S. 62-110.1. Further, Fresh Air identifies that the Commission's Rules set forth three different CPCN processes depending on whether the application for a CPCN is filed by a public utility seeking rate base recovery, a merchant plant or a QF. See Commission Rules R8-61, R8-63 and R8-64. Thus, argues Fresh Air, the statute and rules contemplate that entities other than public utilities will be involved in the generation of electricity in North Carolina. Fresh Air requests that the Commission issue an order declaring that Fresh Air is not a public utility under Chapter 62.

In its comments, NCSEA sets forth four arguments: (1) that North Carolina law is clear and unambiguous about what constitutes a public utility; (2) that the Commission has previously held that QFs under PURPA are not public utilities under Chapter 62; (3) that the costs that Mr. De Luca believes to be unknown are in fact known; and (4) that public policy should dictate that independent power producers are not public utilities.

In his response comments, Mr. De Luca argues that the Public Staff, Fresh Air and NCSEA are ignoring the words "for the public" in the statutory definition of a public utility in G.S. 62-3. Mr. De Luca states that the parties can only make their argument that Fresh Air is not a public utility because Fresh Air is not selling to the public by ignoring the two words "or for" from the statute. Mr. De Luca argues that the Commission is bound by the language of the statute and thus, Fresh Air is a public utility.

Mr. De Luca next responds to the Public Staff's argument that Fresh Air is not a monopoly that can charge excessive rates to retail customers, a primary purpose of regulation. Mr. De Luca states that the "Public Staff concedes that North Carolinians must 'purchase [all] the output from' [Fresh Air]," and "the public has no choice in their selection of the electricity so produced." Mr. De Luca concludes that this combination of federal and state law has created a de facto monopoly under which NC ratepayers have no choice and must purchase the energy generated by Fresh Air. Mr. De Luca argues that the rates that solar facilities, like Fresh Air, are charging are excessive, citing to a Duke filing in Docket E-100, Sub 148, in which Duke argued that the public is being overcharged by $1 billion.

Mr. De Luca contends that any reliance by the parties on the Commission's decision in the Cogentrix docket is misplaced. First, he states that in the Cogentrix docket, the Public Staff initially stated that "it was not clear that [Cogentrix] would not be considered a "public utility" under 62-3(23)." Mr. De Luca then discusses one of the Public Staff's arguments in that case involving G.S. 159F-3(e), which has since been repealed. Mr. De Luca argues this fact is important because this was a statute exempting solar power from being considered a public utility, and in its absence, he argues that the Public Staff recognized that Cogentrix would have been a public utility. Mr. De Luca, however, admits that in the Cogentrix case, the Public Staff filed a supplemental filing arguing that Cogentrix was not a public utility based upon the Simpson case.

Mr. De Luca states that reliance on Simpson is irrelevant and misleading. He argues Simpson involved a doctor providing two-way radio service, which triggers a different part of G.S. 62-3, defining public utilities as only those that transmit messages "to the public." In the present case, he argues that the applicable language that applies to electric service is "to or for the public."

Mr. De Luca also refutes several other arguments of the Public Staff, including, but not limited to the Public Staff's reliance on PURPA to support the finding that Fresh Air is not a public utility for purposes of Chapter 62. Mr. De Luca argues that PURPA creates a monopoly for Fresh Air and if Fresh Air is taking benefit from its monopoly, it must perform its duties on reasonable terms.

Lastly, Mr. De Luca responds to NCSEA's policy argument that if the Commission regulates Fresh Air as a public utility, it would need to regulate residential net metering customers as well which would lead to a nonsensical result. Mr. De Luca responds that net metering customers do not receive payments for their "excess generation," but rather are constructed to offset consumption.

DISCUSSION AND CONCLUSIONS

The Commission determines that Fresh Air is not a public utility under Chapter 62 of the North Carolina General Statutes for purposes of requiring QFs like Fresh Air to provide their costs of producing electricity sold under PURPA to electric utilities. The purpose of PURPA was to overcome the traditional utilities' reluctance to purchase power from non-traditional electric generation facilities and to reduce the financial burden from state and federal regulation on non-traditional facilities. PURPA created a new class of generation facilities known as qualifying facilities, which included non-traditional small power producers and cogeneration facilities. Under PURPA, the interconnecting utility must purchase the power of the QF at the utility's avoided cost, the cost for the incumbent utility to generate the same power itself. Under the PURPA scheme, state public utility commissions exercise authority in setting rates for QFs under guidelines controlled by FERC. FERC is in charge of promulgating regulations affecting QFs, and state public utility commissions are only responsible for implementing FERC's rules and for setting the avoided cost rates. Under PURPA, "the states play the primary role in calculating avoided costs and in overseeing the contractual relationship between [QFs] and utilities operating under the regulations promulgated by the [FERC]." Adrian Energy Assocs. v. Mich. Public Service Commission, 481 F.3d 414 (2007).

In its comments, Fresh Air points the Commission to a FERC order setting forth the objectives of PURPA. FERC, in Order No. 69, explained that:

> Prior to the enactment of PURPA, a cogenerator or small power producer seeking to establish interconnected operation with a utility faced three obstacles ... [one of which was] a cogenerator or small power producer which provided electricity to a utility's grid ran the risk of being considered an electric utility and thus being subjected to State and Federal regulations as an electric utility. Sections 201 and 210 of PURPA are designed to remove these obstacles.

FERC Stats. & Regs. 30,128 (1980) in Docket RM79-55, 45 Fed. Reg. 12,214 (1980). The FERC regulations expressly exempt QFs from certain federal and state laws. Specifically, 18 CFR 292.602(c) states:

> (c) Exemption from certain State laws and regulations.
> (1) Any qualifying facility ... shall be exempted from State laws or regulations respecting:
> (i) The rates of electric utilities; and
> (ii) The financial and organizational regulation of electric utilities.
> ...
> (4) Upon request of any person, the Commission [FERC] may determine whether a qualifying facility is exempt from a particular State law or regulation.

With respect to QFs like Fresh Air under the FERC implemented regulations under PURPA, the Commission is forbidden to establish rates based on cost of service principles set forth in Chapter 62, such as G.S. 62-133. In this respect, a QF is exempt from North Carolina state laws in Chapter 62 respecting rates for traditional electric utilities. Mr. De Luca has indicated that his purpose in having Fresh Air declared a public utility under Chapter 62 is to obtain "access to information to determine the true costs of solar power." Under PURPA and FERC regulations, QF costs are not relevant to any QF ratemaking decisions this Commission undertakes, so declaring Fresh Air a public utility would not enable the cost identification Mr. De Luca seeks.

Mr. De Luca's reliance on the Bowman testimony in the avoided cost docket in support of his argument that QFs, such as Fresh Air, earn revenues in excess of their costs is misplaced. The Bowman testimony supports an argument that DEC and DEP are making that QFs receive revenues under Commission authorized avoided cost rates in excess of what the Companies' avoided costs turn out to be during the period rates are in effect primarily because the cost of natural gas has declined. The QF revenue entitlements the Commission authorizes in avoided cost proceedings are based under PURPA on the costs incumbent electric utilities avoid by purchasing capacity and energy from QFs. Under PURPA, the costs the QFs incur to sell their electrical output to incumbents is not at issue. For example, one element of "avoided costs" under PURPA is fuel costs. A solar PV QF incurs no fuel costs. Witness Bowman's testimony, cited by Mr. De Luca, did not address any QF's actual costs and such costs are not relied upon to set rates a QF can charge.

Mr. De Luca has asked this Commission to interpret Chapter 62 of the North Carolina General Statutes and to find Fresh Air to be a state-regulated public utility so as to require Fresh Air to provide its costs to produce electricity. The Commission concludes that PURPA and FERC's regulations are dispositive to a determination of costs upon which the Commission must rely to establish the avoided costs Fresh Air is entitled to receive. Even if PURPA and the FERC regulations were not dispositive, the Commission determines that upon a review of the Commission's decision in the Cogentrix case, Docket No. SP-100, Sub 0, and the application of the Simpson factors to the present case, that Fresh Air is not a public utility under Chapter 62.

As indicated by the Public Staff, Fresh Air, and NCSEA, the Commission addressed the issue of whether a QF is considered a public utility in its February 29, 1984 Order on Request for a Declaratory Ruling in Docket No. SP-100, Sub 0, the Cogentrix case. The Commission addressed the issue of whether a QF is a public utility under Chapter 62 and concluded that a QF is not a public utility. Mr. De Luca has not persuaded the Commission that Fresh Air is distinguishable from the Cogentrix case.

Mr. De Luca's request also fails under a Simpson analysis. The Simpson Court set forth the following guidelines to consider when determining the definition of a public utility:

> What is the "public" in any given case depends rather on the regulatory circumstances of that case. Some of these circumstances are (1) nature of the industry sought to be regulated; (2) type of market served by the industry; (3) the kind of competition that naturally inheres in that market; and (4) effect of non-regulation or exemption from regulation of one or more persons engaged in the industry. The meaning of "public" must in the final analysis be such as will, in the context of the regulatory circumstances, and as already noted by the Court of Appeals, accomplish "the legislature's purpose and comport with its public policy." 32 N.C. App. at 546, 232 S.E. 2d at 873.

Id. at 524, 246 S.E.2d at 756-57.

In concluding that Simpson's service was offered to the public and, therefore, unauthorized, the court held:

> The radio common carrier industry is therefore a small one whose users fall into definable classes. Were a definition of "public" adopted that allowed prospective offerors of services to approach these separate classes without falling under the statute, the industry could easily shift from a regulated to a largely unregulated one. A service could be operated for doctors or realtors or builders, escape regulation and still capture a substantial portion or even a majority of the market. For example, while Dr. Simpson is offering the service to only ten subscribers, the record indicates there are only 22 radio common carrier subscribers in the whole of Cleveland County. Dr. Simpson is therefore serving over 45 percent of the available market. The end result of the kind of exemption Dr. Simpson argues for could well be that the only subscribers left in the regulated market would be those who fit in no easily definable class. Even if this extreme situation were not reached, unregulated radio services might focus on classes which are easier and more profitable to serve. The result would be to leave burdensome, less profitable service on the regulated portion resulting inevitably in higher prices for the service.

Id. at 525, 246 S.E.2d at 757.

As addressed at length above, the "regulatory circumstances" with respect to QFs are such that they are exempt from public utility status that would make their costs producible in setting rates. In addition, the "market" subject to competition in determining whether the "public" is being served is the retail market. Fresh Air is not selling its electricity to the public in the retail market. Rather, Fresh Air is selling electricity to DEC to sell to the public, which is a sale for resale. Sales of electricity for resale are wholesale sales and part of the wholesale market. Further, the harm that existed in Simpson and other cases where the Commission has found an entity to be a public utility does not exist in the present case. North Carolina has determined that the public is better served by a regulated retail monopoly than by competing suppliers of service. The harm that existed if Simpson was not declared a public utility is that Simpson could cherry pick the incumbent utility's best customers, which would result in reductions in incumbent sales and to stranded costs being foisted on the remaining utilities' customers resulting in higher rates. In the present case, Fresh Air is not competing with DEC to serve retail customers in DEC's franchised service territory. Thus, the harms of not declaring Fresh Air a public utility under Chapter 62 do not exist.

IT IS, THEREFORE, ORDERED that, based upon the filings and arguments as set out above, Fresh Air Energy II, LLC, is not a "public utility" within the meaning of G.S. 62-3(23).

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of August, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Daniel G. Clodfelter did not participate in this decision.

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

BY THE COMMISSION: On May 31, 2017, the Public Staff filed a Motion for Order Requiring Filing of Information Regarding July 1, 2017, Access Rate Changes.

In its Motion, the Public Staff requested that the Commission issue an order requiring filings from certain carriers showing their compliance with the fifth set of intrastate access rate changes mandated by the Federal Communications Commission's November 18, 2011, Universal Service Fund (USF)/ Intercarrier Compensation (ICC) Transformation Order as soon as practicable, but no later than June 19, 2017.

The Public Staff further noted that it has reviewed last year's responses and compiled a list of carriers as reflected in Appendix A to its Motion that the Public Staff believes should make an appropriate filing regarding their 2017 switched access rate changes. The Public Staff stated that, additionally, any carrier that is not listed in Appendix A, but whose status has changed from last year should also be required to make an appropriate filing.

On June 1, 2017, 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, impacted carriers must make the required filings as soon as practicable, but no later than Monday, June 19, 2017.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of June, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. WR-100, SUB 10

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking to Implement North Carolina Session	)	ORDER INITIATING
Laws 2017-10 (Senate Bill 131) and 2017-172	)	RULEMAKING PROCEEDING
(House Bill 799) and Proposal to Amend	)	AND ADOPTING INTERIM
Commission Rule R18-6 Rates	)	RULES AND FORMS

BY THE COMMISSION: On May 4, 2017, North Carolina Session Law 2017-10 (Senate Bill 131) was signed into law by the Governor, having been previously ratified by the North Carolina General Assembly. This legislation, entitled "An Act to Provide Further Regulatory Relief to the Citizens of North Carolina," among other things, modifies G.S. 42-42.1 and G.S. 62-110(g) to remove the statutory requirement that leased properties for which a lessor may charge for the cost of providing water or sewer service to lessees must be contiguous and establishes in G.S. 62-110(g), a new Subsection (4a) and requires that the Commission develop an application that lessors must submit for authority to charge for water or sewer service at single-family dwellings[1] that allows the applicant to serve multiple dwellings in the State subject to approval by the Commission. These statutory changes became effective May 4, 2017.

In addition, on July 21, 2017, North Carolina Session Law 2017-172 (House Bill 799) was signed into law by the Governor, having been previously ratified by the North Carolina General Assembly. This legislation, entitled "An Act to Allow For Landlords to Charge Individual Tenants for Shared Cost of Natural Gas Service Provided to Leased Premises," among other things, modifies certain terminology used in G.S. 42-42.1, Water, Electricity, and Natural Gas Conservation, and G.S. 62-110 (g) related to the water/sewer resale matters addressed in this Order. These statutory changes became effective July 21, 2017.

In order to implement the provisions of Senate Bill 131 and House Bill 799, the Commission proposes certain revisions to the Rules and Regulations in Chapter 18 Provision of Water and Sewer Service by Landlords as presented in Appendix A attached hereto. The Commission is of the opinion that Senate Bill 131 establishes a new, separate, and distinct category of water/sewer resellers[2] related to lessors of single-family dwellings for which additional water/sewer reseller procedures and forms should be adopted on an interim basis, pending review and comment by interested parties. Thus, the Commission proposes to create a new application, Form WRN-1, for use by lessors seeking authority to resale and charge for water and/or sewer service at single-family dwellings that would allow the applicant to serve multiple dwellings in the State subject to approval by the Commission. Consequently, as of the issuance date of this Order, lessors of single-family dwellings who desire to obtain a certificate of authority to charge for water

[1] A single-family dwelling is defined in Appendix A, attached hereto, as "an individual, freestanding, unattached dwelling unit, typically built on a lot larger than the structure itself, resulting in an area surrounding the house known as a yard, which is rented or available for rental as a residence".

[2] The Commission is planning to establish a Company type of WRN to assign to this new category of reseller, such that this type of reseller's docket number would be WRN-___, Sub___.

and/or sewer service and for approval of an administrative fee should apply to the Commission using Form WRN-1. In addition, the Commission has created a proposed notification form, Form WRN-3, for use by lessors of single-family dwellings who, after obtaining Commission certification, due to changes in administrative costs, subsequently seek authority to revise their Commission-approved monthly administrative fee. Further, pursuant to G.S. 62-110(g) (4a), a lessor who receives such authority to resale water and/or sewer service at single-family dwellings will be required to provide an annual update to the Commission which provides, among other things, a current listing of the addresses of all the properties to be served. The Commission proposes Form WRN-2 for use by lessors to provide such annual update. The proposed revisions to the Rules and Regulations in Chapter 18; the proposed Forms WRN-1 and WRN-3; and the proposed annual update report form, Form WRN-2, are attached as Appendices A, B, C, and D, respectively.

Furthermore, the Commission is of the opinion that the proposed revisions to Commission Rules and Regulations addressed herein, as well as the newly proposed Commission forms attached as Appendices B-D, will not change or alter the current procedures and application/notification forms currently in place for the presently certificated water/sewer resellers serving apartment complexes and manufactured home parks or the presently pending applicants for certificates of authority to charge for water and/or sewer service for apartment complexes and manufactured home parks.

In addition, while in the process of modifying the Rules and Regulations in Chapter 18 due to the enactment of Senate Bill 131 and House Bill 799, the Commission also proposes an amendment to Rules R18-6 and R18-7 to authorize water and/or sewer resellers to collect a fee (a "returned check charge"), not to exceed the amount permitted under G.S. 25-3-506, (which is presently $25.00) when a lessee pays a bill for resold water and/or sewer service by check and the check is returned by the bank for insufficient funds or because the lessee does not have an account at the bank. Presently, Rule R18-6 does not explicitly state whether a water and/or sewer reseller is allowed to collect a returned check charge. In recent weeks, the Commission has become aware that water and/or sewer resellers and parties seeking authorization to resell water and/or sewer utility service would like clarification on whether a returned check charge is permitted. The proposed amendments to Rules R18-6 and R18-7 to allow a returned check charge are set forth in the attached Appendix E.

WHEREUPON, the Commission finds good cause to initiate a rulemaking proceeding to implement the statutory changes to G.S. 42-42.1 and G.S. 62-110(g) required by Senate Bill 131 and House Bill 799. Interested parties are requested to file initial comments and reply comments on the Commission's proposed changes to the Rules and Regulations in Chapter 18; the proposed Form WRN-1 application for lessors of single-family dwellings in the State seeking to be regulated as a water and/or sewer reseller; the proposed Form WRN-3, for notification by lessors to seek authority to revise their Commission-approved monthly administrative fee; and the proposed annual update, Form WRN-2, to assist the Commission in adopting final rules and applicable Commission forms. Further, interested parties are also requested to file initial comments and reply comments on the Commission's proposed additions to Rules R18-6 and R18-7, concerning a returned check charge, and to specifically comment on whether such proposed amendment is compatible with G.S. 42-42.1 and G.S. 62-110(g). After careful consideration of the initial comments and reply comments the Commission will issue final rules and forms.

IT IS, THEREFORE, ORDERED as follows:

1. That the proposed revisions to Commission Rules and Regulations contained in Chapter 18, attached as Appendix A (a version reflecting the proposed revisions[1] and a clean copy); Form WRN-1, attached as Appendix B; Form WRN-3, attached as Appendix C; and Form WRN-2, attached as Appendix D are hereby adopted on an interim basis effective as of the date of this Order and continuing in effect until final rules and forms shall be adopted and issued by further order of the Commission.

2. That the proposed amendments to Rules R18-6 and R18-7 to allow a returned check charge are set forth in the attached Appendix E (a version reflecting the proposed revisions[2] and a clean copy).

3. That the Chief Clerk shall serve a copy of this Order on all providers charging for water and/or sewer utility service pursuant to certificates of authority granted by the Commission pursuant to G.S. 62-110(g) and Chapter 18 of the Commission's Rules and Regulations, all providers with pending applications seeking such certificates of authority, the Public Staff – North Carolina Utilities Commission, and the Attorney General.

4. That any person having an interest in this proceeding may file a petition to intervene and initial comments on the proposed rules, the proposed forms, and whether resellers of water and/or sewer utility service should be authorized to collect a returned check charge under the circumstances described herein on or before Friday, September 29, 2017, and may file reply comments on or before Friday, October 13, 2017.

5. That, after receiving comments and reply comments from interested parties, the Commission shall determine whether a water and/or sewer reseller is permitted pursuant to general statutes to collect a returned check charge and shall issue a further order of the Commission concerning the applicable changes to Rules R18-6 and R18-7 in Chapter 18 of the Commission Rules and Regulations.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of August, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

Chairman Edward S. Finley, Jr., did not participate in this decision.

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[1] Deletions from the current wording of the rules are shown by strikethrough and additions are shown by underlining.

[2] Id.

Rules R18-1 through R18-8 of Chapter 18
Provision of Water and Sewer Service by Lessors ~~Landlords~~.[1]

Rule R18-1. Application.

This Chapter governs charging for the costs of providing water or sewer utility service by a lessor to a lessee as authorized by G.S. 62-110(g).

Rule R18-2. Definitions.

(a) *Apartment.* A building containing multiple residential dwelling units. For the purposes of these Rules, townhouses, row houses, and/or condominiums shall be considered apartments.

~~(c)~~ (b) *Apartment complex.* Premises where one or more buildings under common ownership comprising 15 or more apartments are available for rental to lessees. ~~tenants.~~

~~(a)~~ (c) ~~*Same*~~ ~~c~~*Contiguous* *dwelling units.* ~~*premises.*~~ An apartment complex or manufactured home park located on property that is not separated by property owned by others. Property will be considered contiguous even if intersected by a public thoroughfare if, absent the thoroughfare, the property would be contiguous.

(d) *Dwelling unit.* A house, mobile home, apartment, building, or other structure used for residential purposes.

(e) *Leased premises.* A house, mobile home, apartment, building, or any combination thereof which are leased for residential purposes.

~~(d)~~ (f) *Lessee.* ~~*Tenant.*~~ ~~The lessee of property from the landlord, to whom the water or sewer service purchased by the provider from the supplier is provided.~~ A person who leases a dwelling unit from the lessor.

(g) *Lessor.* A person, entity, corporation, or agency who owns 15 or more dwelling units which are available for lease. The lessor is also known as the landlord.

~~(f)~~ (h) *Manufactured home park.* Premises where a combination of 15 or more manufactured homes, as defined in G.S. 143-145(7), or spaces for manufactured homes, are rented to or are available for rental to lessees ~~tenants.~~

~~(b)~~ (i) *Provider.* The lessor ~~landlord~~ purchasing water or sewer utility service from a supplier and charging for the costs of providing the service or services to lessees ~~tenants.~~ The provider shall be the owner of the residential premises served.

(j) *Single-family dwelling.* An individual, freestanding, unattached dwelling unit, typically built on a lot larger than the structure itself, resulting in an area surrounding the house known as a yard, which is rented or available for rental as a residence.

~~(e)~~ (k) *Supplier.* A public utility or an agency or organization exempted from regulation from which a provider purchases water or sewer service.

~~(g)~~ (l) *Supplier's base charge.* The fixed charge imposed by the supplier for providing water and sewer utility service to the provider. This charge may include charges related to the provision of utility service such as the cost of meter reading, billing, and collecting, but may not include charges not related to the provision of utility service, such as stormwater fees, trash collection, or property taxes.

Rule R18-3. Utility status; certificate; bonds.

Every provider is a public utility as defined by G.S. 62-3(23)a.2 and shall comply with all applicable provisions of the Public Utilities Act and all applicable rules and regulations of the Commission. No provider shall begin charging for the costs of providing water or sewer service prior to applying for and receiving a certificate of authority from the Commission. No provider shall be required to post a bond pursuant to G.S. 62-110.3.

Every application for authority to charge for the costs of providing water or sewer service by an applicant owning an apartment, apartment complex, or manufactured home park shall be in such form and detail as the Commission may prescribe and shall include (a) a description of the applicant and the property to be served, (b) a description of the proposed billing method and billing statements, (c) a schedule of the rates charged to the applicant by the supplier(s), (d) the schedule of rates the applicant proposes to charge the applicant's ~~customers~~ lessees, (e) the administrative fee proposed to be charged by the applicant, (f) the name of and contact information for the applicant and its agents, (g) the name of and contact information for the supplying water or sewer system, and (h) any additional information that the Commission may require.

Every application for authority to charge for the costs of providing water or sewer service by an applicant owning a single-family dwelling shall be in such form and detail as the Commission may prescribe; shall allow the applicant to serve multiple dwellings in the State subject to an approval by the Commission; and shall include (a) a description of the applicant and a listing of the addresses of all properties to be served. An updated listing of addresses served by the applicant shall be provided to the Commission annually, (b) a description of the proposed billing method and billing statements, (c) the administrative fee proposed to be charged by the applicant, (d) the name of and contact information for the applicant and its agents, (e) the name(s) of the water and/or sewer supplier(s), and (f) any additional information that the Commission may require.

The Commission shall approve or disapprove an application within 30 days of the filing of a completed application with the Commission. In the event an application is found to be incomplete as submitted, the applicant will be notified accordingly; and will have 60 days from the date the application is received in the Office of the Chief Clerk to complete it, including submission of all required supporting documentation. If the Commission has not issued an Order disapproving a completed application within 30 days, the application shall be deemed approved.

Rule R18-4. Compliance with rules. [No proposed changes in R18-4.]

Every provider shall comply with any applicable rules of local governmental agencies regarding the provision of water or sewer service.

Rule R18-5. Records, reports and fees.

(a) All records shall be kept at the office or offices of the provider in North Carolina, or shall be made available at its office in North Carolina upon request, and shall be available during regular business hours for examination by the Commission or Public Staff or their duly authorized representatives. Within three business days after a written request to the provider, a ~~customer~~ lessee may examine the records pertaining to the ~~customer's~~ lessee's account during regular business hours and may obtain a copy of those records at a reasonable cost, which shall not exceed ~~twenty-five cents ($0.25)~~ 25¢ per page.

(b) Providers shall not be required to file an annual report to the Commission as required by Chapter 1, Rule R1-32 of the Rules and Regulations of the North Carolina Utilities Commission except as required by Commission Rule R18-3. Providers shall pay a regulatory fee and file a regulatory fee report as required by Chapter 15, Rule R15-1. Special reports shall also be made concerning any particular matter upon request by the Commission.

Rule R18-6. Rates.

(a) The rates shall equal the cost of purchased water or sewer service (The usage rate charged by the provider shall equal the usage rate charged by the supplier.). A Commission-approved administrative fee not to exceed ~~three dollars and seventy five cents ($3.75)~~ $3.75 may be added to the cost of purchased water and sewer service to compensate the provider for meter reading, billing, and collection. A provider whose schedule of rates and fees does not include a separate base charge to the lessee ~~tenant~~ may request approval of ~~an~~ a pass through of the base charge from the supplier to be included in the administrative fee resulting in a request for approval by the provider of a total monthly administrative fee greater than $3.75. ~~greater than three dollars and seventy-five cents ($3.75) to recover the base charge from its supplier~~. With the exception of base charges approved before August 1, 2004, all charges other than the administrative fee shall be based on lessees' ~~tenants'~~ metered consumption of water. All sewer service shall be measured based on the amount of water metered. Metered consumption of water shall be determined by metered measurement of all water consumed by the lessee, ~~tenant,~~ and not by any partial measurement of water consumption (i.e., ratio utility billing system (RUBS) and hot water capture, cold water allocation (HWCCWA) are not allowed), except as permitted in G.S. 62-110(g)(1a) and Commission Rule R18-~~08~~8).

(b) A provider of water or sewer service may track increases in the unit consumption rate charged by the supplier of such service, and may (subject to limitations imposed by Commission Rules) change its administrative fee, by filing with the Commission a notification of revised schedule of rates and fees. Every notification of revised schedule of rates and fees shall be in such form and detail as the Commission may prescribe and shall include (1) the current schedule of the unit consumption rates charged by the provider, (2) the schedule of unit consumption rates charged by the supplier to the provider that the provider proposes to pass through to the provider's ~~customers~~ lessees, (3) the schedule of the unit consumption rates proposed to be charged by the provider, (4) the current administrative fee charged by the provider, and, if applicable, (5) the administrative fee proposed to be charged by the provider. Any such notification of revised schedule of rates and fees shall be presumed valid and shall be allowed to become effective simultaneously with the increase in the unit consumption rate of the supplier upon 14 days' notice to the Commission, unless otherwise suspended or disapproved by Commission Order issued within 14 days after filing.

(c) Every request for approval of ~~an~~ a monthly fixed administrative fee in excess of ~~three dollars and seventy-five cents ($3.75)~~ $3.75 shall include (1) the provider's current and proposed cost of meter reading, billing, and collection not to exceed the Commission-approved amount of $3.75, (2) the current or proposed base charge from the supplier, if applicable, ~~(3) the number of tenants to whom water and sewer service is provided, and (4) the proposed administrative fee~~ (3) the total proposed monthly fixed administrative fee, and (4) the number of lessees ~~tenants~~ to whom water or sewer service is provided. Any such request shall be suspended for a period of 30 days after filing.

(d) No provider shall charge or collect any greater or lesser compensation for the costs of providing water or sewer service than the rates approved by the Commission.

Rule R18-7. Disconnection; billing procedure; meter reading.

(a) No charge for connection or disconnection, charge for late payment, or similar charge in addition to the rate specified in Rule R18-6 shall be allowed.

(b) No provider may disconnect water or sewer service for nonpayment.

(c) Bills shall be rendered at least monthly.

(d) The date after which a bill for water or sewer utility service is due, or the past due after date, shall be disclosed on the bill and shall not be less than ~~twenty-five (25)~~ 25 days after the billing date.

(e) A provider shall not bill for or attempt to collect for excess usage resulting from a plumbing malfunction or other condition which is not known to the lessee ~~tenant~~ or which has been reported to the provider.

(f) Every provider shall provide to each ~~customer~~ lessee at the time the lease agreement is signed, and shall maintain in its business office, in public view, near the place where payments are received, the following:

(1) A copy of the rates, rules and regulations of the provider applicable to the premises served from that office.

(2) A copy of these rules and regulations.

(3) A statement advising lessees ~~tenants~~ that they should first contact the provider's office with any questions they may have regarding bills or complaints about service, and that in cases of dispute, they may contact the Commission either by calling the Public Staff - North Carolina Utilities Commission, Consumer Services Division, at ~~(919)~~ 919-733-9277 or by appearing in person or writing the Public Staff - North Carolina Utilities Commission, Consumer Services Division, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300~~26~~.

(g) Each provider shall adopt some means of informing its lessees ~~tenants~~ as to the method of reading meters. Information on bills shall be governed by Chapter 7, Rule R7-23 and Chapter 10, Rule R10-19. Additionally, the bill shall contain a toll-free phone number for contacting the provider or the agent regarding service or billing matters. Adjustment of bills for meter error shall be governed by Chapter 7, Rule R7-25. Testing of water meters shall be governed by Chapter 7, Rules R7-28 through R7-33.

Rule R18-8. Hot water capture, cold water allocation.

(a) Pursuant to G.S. 62-110(g)(1a), if the ~~contiguous~~ leased premises are contiguous dwelling units ~~were~~ built prior to 1989, and the provider determines that, due to the plumbing configuration of the building, measurement of the lessee's ~~tenant's~~ total water usage is impractical or is not economical, the provider may estimate each lessee's ~~tenant's~~ total water usage based upon the hot water usage of each lessee ~~tenant~~ as a percentage of all of the lessees' ~~tenants'~~ hot water usage.

(b) The provider must file the appropriate application (Application for Certificate of Authority to Charge for Water and/or Sewer Service Utilizing the Hot Water Capture, Cold Water Allocation

Method and for Approval of Rates for Apartment Complexes and Manufactured Home Parks) and receive Commission authorization prior to commencing utilization of the hot water capture, cold water allocation method of estimating water usage.

(c) The provider shall not include in a lessee's ~~tenant's~~ bill the cost of water and sewer service used in common areas or water loss due to leaks in the provider's water mains. A provider shall not bill or attempt to collect for excess water usage resulting from a plumbing malfunction or other condition that is not known to the lessee ~~tenant~~ or that has been reported to the provider. The provider may choose to satisfy the common area

water usage exclusion utilizing one of the following methods (the default method is method 1.):

(1) The provider shall reduce the total water amount of water purchased by 20 ~~percent~~%;

(2) Where all common areas are separately metered, the provider shall subtract the actual common area usage from the total amount of water purchased. The provider shall provide the Commission and the Public Staff with a quarterly report (filed 45 days after the end of each quarter) documenting the common area metered usage, the total amount of water purchased, and the computation of the lessees' ~~tenants'~~ bills;

(3) Where no common areas are separately metered, the provider shall subtract 15 ~~percent~~% from the total amount of water purchased where there is an installed landscape irrigation system and subtract 5 ~~percent~~% from the total amount of water purchased for each swimming pool or laundry room. The provider shall provide the Commission and the Public Staff with a quarterly report (filed 45 days after the end of each quarter) documenting the common area allocated usage, the total amount of water purchased, and the computation of the lessees' ~~tenants'~~ bills; and

(4) Where some common areas are separately metered and some are not metered, the provider shall subtract the actual common area usage from the total amount of water purchased and shall subtract 15 ~~percent~~ % from the total amount of water purchased where there is an unmetered installed landscape irrigation system and subtract 5 ~~percent~~ % from the total amount of water purchased for each unmetered swimming pool or laundry room. The provider shall provide the Commission and the Public Staff with a quarterly report (filed 45 days after the end of each quarter) documenting the common area metered usage, common area allocated usage, the total amount of water purchased, and the computation of the lessees' ~~tenants'~~ bills.

(d) The provider shall furnish a water/sewer utility bill to the lessees ~~tenants~~ which clearly states that the hot water capture, cold water allocation method of estimating the bill has been utilized and contains the following information for each monthly billing period:

(1) Total amount of water purchased by the provider;
(2) Total amount of water purchased less the metered and/or allocated common area usage (utilizing one of the methods above (1-4));
(3) Total amount of hot water measured for all lessees; ~~tenants;~~
(4) Amount of hot water measured for the individual lessee ~~tenant~~;
(5) Amount of water the individual lessee ~~tenant~~ is being billed;
(6) Amount owed for the current billing period;
(7) Beginning and ending dates for the billing period;

(8) Past due date; and
(9) A local or toll-free telephone number and address that the lessee ~~tenant~~ can use to obtain more information about the bill.

(e) The provider shall not utilize a ratio utility billing system or other allocation billing system that does not rely on individually submetered hot water usage to determine the allocation of water and sewer usage.

Rules R18-1 through R18-8 of Chapter 18
Provision of Water and Sewer Service by Lessors.

Rule R18-1. Application.

This Chapter governs charging for the costs of providing water or sewer utility service by a lessor to a lessee as authorized by G.S. 62-110(g).

Rule R18-2. Definitions.

(a) *Apartment.* A building containing multiple residential dwelling units. For the purposes of these Rules, townhouses, row houses, and/or condominiums shall be considered apartments.

(b) *Apartment complex.* Premises where one or more buildings under common ownership comprising 15 or more apartments are available for rental to lessees.

(c) *Contiguous dwelling units.* An apartment complex or manufactured home park located on property that is not separated by property owned by others. Property will be considered contiguous even if intersected by a public thoroughfare if, absent the thoroughfare, the property would be contiguous.

(d) *Dwelling unit.* A house, mobile home, apartment, building, or other structure used for residential purposes.

(e) *Leased premises.* A house, mobile home, apartment, building, or any combination thereof which are leased for residential purposes.

(f) *Lessee.* A person who leases a dwelling unit from the lessor.

(g) *Lessor.* A person, entity, corporation, or agency who owns 15 or more dwelling units which are available for lease. The lessor is also known as the landlord.

(h) *Manufactured home park.* Premises where a combination of 15 or more manufactured homes, as defined in G.S. 143-145(7), or spaces for manufactured homes, are rented to or are available for rental to lessees.

(i) *Provider.* The lessor purchasing water or sewer utility service from a supplier and charging for the costs of providing the service or services to lessees. The provider shall be the owner of the residential premises served.

(j) *Single-family dwelling.* An individual, freestanding, unattached dwelling unit, typically built on a lot larger than the structure itself, resulting in an area surrounding the house known as a yard, which is rented or available for rental as a residence.

(k) *Supplier.* A public utility or an agency or organization exempted from regulation from which a provider purchases water or sewer service.

(l) *Supplier's base charge.* The fixed charge imposed by the supplier for providing water and sewer utility service to the provider. This charge may include charges related to the provision of utility service such as the cost of meter reading, billing, and collecting, but may not include charges not related to the provision of utility service, such as stormwater fees, trash collection, or property taxes.

Rule R18-3. Utility status; certificate; bonds.

Every provider is a public utility as defined by G.S. 62-3(23)a.2 and shall comply with all applicable provisions of the Public Utilities Act and all applicable rules and regulations of the Commission. No provider shall begin charging for the costs of providing water or sewer service prior to applying for and receiving a certificate of authority from the Commission. No provider shall be required to post a bond pursuant to G.S. 62-110.3.

Every application for authority to charge for the costs of providing water or sewer service by an applicant owning an apartment, apartment complex, or manufactured home park_shall be in such form and detail as the Commission may prescribe and shall include (a) a description of the applicant and the property to be served, (b) a description of the proposed billing method and billing statements, (c) a schedule of the rates charged to the applicant by the supplier(s), (d) the schedule of rates the applicant proposes to charge the applicant's lessees, (e) the administrative fee proposed to be charged by the applicant, (f) the name of and contact information for the applicant and its agents, (g) the name of and contact information for the supplying water or sewer system, and (h) any additional information that the Commission may require.

Every application for authority to charge for the costs of providing water or sewer service by an applicant owning a single-family dwelling shall be in such form and detail as the Commission may prescribe; shall allow the applicant to serve multiple dwellings in the State subject to an approval by the Commission; and shall include (a) a description of the applicant and a listing of the addresses of all properties to be served. An updated listing of addresses served by the applicant shall be provided to the Commission annually, (b) a description of the proposed billing method and billing statements, (c) the administrative fee proposed to be charged by the applicant, (d) the name of and contact information for the applicant and its agents, (e) the name of the water and/or sewer supplier, and (f) any additional information that the Commission may require.

The Commission shall approve or disapprove an application within 30 days of the filing of a completed application with the Commission. In the event an application is found to be incomplete as submitted, the applicant will be notified accordingly; and will have_60 days from the date the application is received in the Office of the Chief Clerk to complete it, including submission of all required supporting documentation. If the Commission has not issued an Order disapproving a completed application within 30 days, the application shall be deemed approved.

Rule R18-4. Compliance with rules.

Every provider shall comply with any applicable rules of local governmental agencies regarding the provision of water or sewer service.

Rule R18-5. Records, reports and fees.

(a) All records shall be kept at the office or offices of the provider in North Carolina, or shall be made available at its office in North Carolina upon request, and shall be available during regular business hours for examination by the Commission or Public Staff or their duly authorized representatives. Within three business days after a written request to the provider, a lessee may examine the records pertaining to the lessee's account during regular business hours and may obtain a copy of those records at a reasonable cost, which shall not exceed 25¢ per page.

(b) Providers shall not be required to file an annual report to the Commission as required by Chapter 1, Rule R1-32 of the Rules and Regulations of the North Carolina Utilities Commission except as required by Commission Rule R18-3. Providers shall pay a regulatory fee and file a regulatory fee report as required by Chapter 15, Rule R15-1. Special reports shall also be made concerning any particular matter upon request by the Commission.

Rule R18-6. Rates.

(a) The rates shall equal the cost of purchased water or sewer service (The usage rate charged by the provider shall equal the usage rate charged by the supplier.). A Commission-approved administrative fee not to exceed $3.75 may be added to the cost of purchased water and sewer service to compensate the provider for meter reading, billing, and collection. A provider whose schedule of rates and fees does not include a separate base charge to the lessee may request approval of a pass through of the base charge from the supplier to be included in the administrative fee resulting in a request for approval by the provider of a total monthly administrative fee greater than $3.75. With the exception of base charges approved before August 1, 2004, all charges other than the administrative fee shall be based on lessees' metered consumption of water. All sewer service shall be measured based on the amount of water metered. Metered consumption of water shall be determined by metered measurement of all water consumed by the lessee, and not by any partial measurement of water consumption (i.e., ratio utility billing system (RUBS) and hot water capture, cold water allocation (HWCCWA) are not allowed), except as permitted in G.S. 62-110(g)(1a) and Commission Rule R18-8).

(b) A provider of water or sewer service may track increases in the unit consumption rate charged by the supplier of such service, and may (subject to limitations imposed by Commission Rules) change its administrative fee, by filing with the Commission a notification of revised schedule of rates and fees. Every notification of revised schedule

of rates and fees shall be in such form and detail as the Commission may prescribe and shall include (1) the current schedule of the unit consumption rates charged by the provider, (2) the schedule of unit consumption rates charged by the supplier to the provider that the provider proposes to pass through to the provider's lessees, (3) the schedule of the unit consumption rates proposed to be charged by the provider, (4) the current administrative fee charged by the provider, and, if applicable, (5) the administrative fee proposed to be charged by the provider. Any such notification of revised schedule of rates and fees shall be presumed valid and shall be allowed to become effective simultaneously with the increase in the unit consumption rate of the supplier upon 14 days' notice to the Commission, unless otherwise suspended or disapproved by Commission Order issued within 14 days after filing.

(c) Every request for approval of a monthly fixed administrative fee in excess of $3.75 shall include (1) the provider's current and proposed cost of meter reading, billing, and collection not to exceed the Commission-approved amount of $3.75, (2) the current or proposed base charge from the supplier, if applicable, (3) the total proposed monthly fixed administrative fee, and (4) the number of lessees to whom water or sewer service_is provided. Any such request shall be suspended for a period of 30 days after filing.

(d) No provider shall charge or collect any greater or lesser compensation for the costs of providing water or sewer service than the rates approved by the Commission.

Rule R18-7. Disconnection; billing procedure; meter reading.

(a) No charge for connection or disconnection, charge for late payment, or similar charge in addition to the rate specified in Rule R18-6 shall be allowed.

(b) No provider may disconnect water or sewer service for nonpayment.

(c) Bills shall be rendered at least monthly.

(d) The date after which a bill for water or sewer utility service is due, or the past due after date, shall be disclosed on the bill and shall not be less than 25 days after the billing date.

(e) A provider shall not bill for or attempt to collect for excess usage resulting from a plumbing malfunction or other condition which is not known to the lessee or which has been reported to the provider.

(f) Every provider shall provide to each lessee at the time the lease agreement is signed, and shall maintain in its business office, in public view, near the place where payments are received, the following:

(1) A copy of the rates, rules and regulations of the provider applicable to the premises served from that office.

(2) A copy of these rules and regulations.

(3) A statement advising lessees that they should first contact the provider's office with any questions they may have regarding bills or complaints about service, and that in cases of dispute, they may contact the Commission either by calling the Public Staff - North Carolina Utilities Commission, Consumer Services Division, at 919-733-9277 or by appearing in person or writing the Public Staff - North Carolina Utilities Commission, Consumer Services Division, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300.

(g) Each provider shall adopt some means of informing its lessees as to the method of reading meters. Information on bills shall be governed by Chapter 7, Rule R7-23 and Chapter 10, Rule R10-19. Additionally, the bill shall contain a toll-free phone number for contacting the provider or the agent regarding service or billing matters. Adjustment of bills for meter error shall be governed by Chapter 7, Rule R7-25. Testing of water meters shall be governed by Chapter 7, Rules R7-28 through R7-33.

Rule R18-8. Hot water capture, cold water allocation.

(a) Pursuant to G.S. 62-110(g)(1a), if the leased premises are contiguous dwelling units built prior to 1989, and the provider determines that, due to the plumbing configuration of the building, measurement of the lessee's total water usage is impractical or is not economical, the provider may estimate each lessee's total water usage based upon the hot water usage of each lessee as a percentage of all of the lessees' hot water usage.

(b) The provider must file the appropriate application (Application for Certificate of Authority to Charge for Water and/or Sewer Service Utilizing the Hot Water Capture, Cold Water Allocation Method and for Approval of Rates for Apartment Complexes and Manufactured Home Parks) and receive Commission authorization prior to commencing utilization of the hot water capture, cold water allocation method of estimating water usage.

(c) The provider shall not include in a lessee's bill the cost of water and sewer service used in common areas or water loss due to leaks in the provider's water mains. A provider shall not bill or attempt to collect for excess water usage resulting from a plumbing malfunction or other condition that is not known to the lessee or that has been reported to the provider. The provider may choose to satisfy the common area water usage exclusion utilizing one of the following methods (the default method is method 1.):

(1) The provider shall reduce the total water amount of water purchased by 20%;

(2) Where all common areas are separately metered, the provider shall subtract the actual common area usage from the total amount of water purchased.

The provider shall provide the Commission and the Public Staff with a quarterly report (filed 45 days after the end of each quarter) documenting the common area metered usage, the total amount of water purchased, and the computation of the lessees' bills;

(3) Where no common areas are separately metered, the provider shall subtract 15% from the total amount of water purchased where there is an installed landscape irrigation system and subtract 5% from the total amount of water purchased for each swimming pool or laundry room. The provider shall provide the Commission and the Public Staff with a quarterly report (filed 45 days after the end of each quarter) documenting the common area

allocated usage, the total amount of water purchased, and the computation of the lessees' bills; and

(4) Where some common areas are separately metered and some are not metered, the provider shall subtract the actual common area usage from the total amount of water purchased and shall subtract 15% from the total amount of water purchased where there is an unmetered installed landscape irrigation system and subtract 5% from the total amount of water purchased for each unmetered swimming pool or laundry room. The provider shall provide the Commission and the Public Staff with a quarterly report (filed 45 days after the end of each quarter) documenting the common area metered usage, common area allocated usage, the total amount of water purchased, and the computation of the lessees' bills.

(d) The provider shall furnish a water/sewer utility bill to the lessees which clearly states that the hot water capture, cold water allocation method of estimating the bill has been utilized and contains the following information for each monthly billing period:

(1) Total amount of water purchased by the provider;
(2) Total amount of water purchased less the metered and/or allocated common area usage (utilizing one of the methods above (1-4));
(3) Total amount of hot water measured for all lessees;
(4) Amount of hot water measured for the individual lessee;
(5) Amount of water the individual lessee is being billed;
(6) Amount owed for the current billing period;
(7) Beginning and ending dates for the billing period;
(8) Past due date; and
(9) A local or toll-free telephone number and address that the lessee can use to obtain more information about the bill.

(e) The provider shall not utilize a ratio utility billing system or other allocation billing system that does not rely on individually submetered hot water usage to determine the allocation of water and sewer usage.

FORM WRN-1
ESTABLISHED 08/2017

APPENDIX B

DOCKET NO. WRN-_______Sub_____
FILING FEE RECEIVED __________

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
APPLICATION FOR CERTIFICATE OF AUTHORITY TO CHARGE FOR WATER AND/OR SEWER SERVICE AND FOR APPROVAL OF ADMINISTRATIVE FEE FOR SINGLE-FAMILY DWELLINGS

APPLICANT

1. Name of Owner: ______________________________
2. Business Mailing Address of Owner: ______________________________
3. City and State: ______________________________ Zip Code: ______________
4. Business Telephone: ______________________ Business Fax: ______________________
5. Business Email: ______________________________
6. Person to Contact Concerning this Application (Name, Telephone, and Email):

____

CONTACT INFORMATION

	NAME	ADDRESS	TELEPHONE
7. Management Company:	______	______	______
8. Complaints or Billing:	______	______	______
9. Emergency Services:	______	______	______
10. Filing/Payment of Regulatory Fees to NCUC:	______	______	______

PROPOSED ADMINISTRATIVE FEE FOR BILLING AND COLLECTION

(Amount Applicant Proposes to Charge)

11. Monthly administrative fee: ______________________________
    (NCUC Rule R18-6(a) specifies that no more than $3.75 may be added to the cost of purchased water and sewer service as an administrative fee to compensate the lessor (provider) for meter reading, billing, and collection expenses.)

PROPOSED BILLING INFORMATION

12. Bills past due ______ days after billing date.
    (NCUC Rule R18-7(d) specifies that bills shall not be past due less than 25 days after billing dates.)
13. Billing cycle: Monthly? _________ (NCUC Rule R18-7(c) specifies that bills shall be rendered at least monthly.)
14. Description of billing statement (or attach a sample bill): ______________________________
15. _____ YES (Indicate agreement by inserting a checkmark √). The Applicant understands that the Certificate of Authority to charge for water and/or sewer service at single-family dwellings owned by the Applicant will allow the lessor to charge for the costs of providing water or sewer service to lessees who occupy the leased premises. All charges, except the supplier's base charge, for water or sewer service shall be based on the user's metered consumption of water, which shall be determined by metered measurement of all water consumed. The rates charged by the lessor (provider) shall not exceed the unit consumption rate charged by the supplier of the service. That is, the lessor (provider) may pass through the consumption rates charged by the supplier to the provider's lessees. The lessor may also charge a monthly administrative fee not to exceed the maximum administrative fee authorized by the Commission, as indicated in Item 11 above.

FORM WRN-1
ESTABLISHED 08/2017

16. **Listing of All Properties in North Carolina for which Certificate of Authority Is Requested:**

PROPOSED UTILITY SERVICE AREAS

	Physical Address	City	County	Type of Service (Water and/or Sewer)	Supplier(s)
Property No. 1					
Property No. 2					
Property No. 3					
Property No. 4					
Property No. 5					
Property No. 6					
Property No. 7					
Property No. 8					
Property No. 9					
Property No. 10					
Property No. 11					
Property No. 12					

Property No. 13 ____

Property No. 14 ____

Property No. 15 ____

Property No. 16 ____

Property No. 17 ____

Property No. 18 ____

Property No. 19 ____

Property No. 20 ____

FORM WRN-1
ESTABLISHED 08/2017

16. Listing of All Properties in North Carolina for which Certificate of Authority Is Requested – Continued:

PROPOSED UTILITY SERVICE AREAS

	Physical Address	City	County	Type of Service (Water and/or Sewer)	Supplier(s)
Property No. 21					
Property No. 22					
Property No. 23					
Property No. 24					

Property No. 25 ____________________

Property No. 26 ____________________

Property No. 27 ____________________

Property No. 28 ____________________

Property No. 29 ____________________

Property No. 30 ____________________

Property No. 31 ____________________

Property No. 32 ____________________

Property No. 33 ____________________

Property No. 34 ____________________

Property No. 35 ____________________

Property No. 36 ____________________

Property No. 37 ____________________

Property No. 38 ____________________

Property No. 39 ____________________

Property No. 40 ____________________

(Attach supplemental sheets, if needed.)

FORM WRN-1
ESTABLISHED 08/2017

REQUIRED EXHIBITS

(1) Exhibit A: If the Applicant is a corporation, LLC, LP, etc., enclose a copy of the certification from the North Carolina Department of the Secretary of State (Articles of Incorporation or Application for Certificate of Authority for Limited Liability Company, etc.). **(Must match name on Line 1 of application.)**

(2) Exhibit B: If the Applicant is a partnership, enclose a copy of the partnership agreement. **(Must match name on Line 1 of application.)**

(3) Exhibit C: A copy of the warranty deeds showing that the Applicant has ownership of all the properties listed in Item 16. **(Grantee on the Deed must match owner's name on Line 1 of application.)**

(4) Exhibit D: Vicinity maps (i.e., Google Maps) showing the locations of the single-family dwellings listed in Item 16 in sufficient detail for someone not familiar with the counties to locate the dwellings.

(5) Exhibit E: A copy of final executed agreements or contracts, if any, that the Applicant has entered into covering the provision of the billing and collection services. (The agreements/contracts need to be signed by both the owner and the billing and collection company).

FILING INSTRUCTIONS

(6) If additional space is needed, supplementary sheets may be attached. If any section does not apply, write "not applicable".

(7) Electronic filing is available at www.ncuc.net for application submittal or mail one (1) original application with required exhibits and **original notarized signature**, 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

(8) Provide a self-addressed stamped envelope, plus an additional copy of the application, if a file-stamped copy is requested by the Applicant.

(9) Enclose a filing fee as required by G.S. §62-300. A Class A company (annual revenues of $1,000,000 or more) requires a $250 filing fee. A Class B company (annual revenues between $200,000 and $1,000,000) requires a $100 filing fee. A Class C company (annual revenues less than $200,000) requires a $25 filing fee.

MAKE CHECK PAYABLE TO N.C. DEPARTMENT OF COMMERCE/UTILITIES COMMISSION.

SIGNATURE

Application shall be signed and verified by the Applicant.

____
Signature

____
Typed or Printed Name

____
Date

(Typed or Printed Name) ______________________________

Personally appearing before me and, being first duly sworn, says that the information contained in this application and in the exhibits attached hereto are true to the best of his/her knowledge and belief.

Subscribed and sworn before me this the ______ day of ______________, 20________.

____
Signature of Notary Public

____
Name of Notary Public – Typed or Printed

My Commission Expires: ____________

FORM WRN-3
ESTABLISHED 08/2017

APPENDIX C

DOCKET NO. WRN-_____Sub____

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
NOTIFICATION OF REVISED ADMINISTRATIVE FEE FOR SINGLE-FAMILY DWELLINGS
CHARGING FOR WATER AND/OR SEWER SERVICE PURSUANT TO G.S. 62-110(G)

APPLICANT

1. Name of Owner: ______________________________
2. Business Mailing Address of Owner: ______________________________
3. City and State: ______________________ Zip Code: ______________
4. Business Telephone: ______________ Business Fax: ______________
5. Business Email: ______________________________
6. Person to Contact Concerning this Notification (Name, Telephone, and Email):

____

CONTACT INFORMATION

	NAME	ADDRESS	TELEPHONE
7. Management Company:	____________	____________	____________
8. Complaints or Billing:	____________	____________	____________
9. Emergency Services:	____________	____________	____________
10. Filing/Payment of Regulatory Fees to NCUC:	____________	____________	____________

PROPOSED AND PRESENT ADMINISTRATIVE FEE

	Proposed Fee	Present Fee
11. Monthly Administrative Fee:	____________	____________

(NCUC Rule R18-6(a) specifies that no more than $3.75 may be added to the cost of purchased water and sewer service as an administrative fee to compensate the lessor (provider) for meter reading, billing, and collection expenses.)

12. Present administrative fee established: Docket No. WRN-____________Sub____________

PROPOSED BILLING INFORMATION

13. Bills past due ______ days after billing date.
    (NCUC Rule R18-7(d) specifies that bills shall not be past due less than 25 days after billing dates.)
14. Billing cycle: Monthly? _________ (NCUC Rule R18-7(c) specifies that bills shall be rendered at least monthly.)
15. _____ YES (Indicate agreement by inserting a checkmark √). The consumption rate(s) and base fee(s) charged by the lessor (provider) shall not exceed the unit consumption rate(s) and base fee(s) charged by the supplier of the service. That is, the lessor (provider) may pass through the consumption rate(s) on metered service and the base fee(s) charged by the supplier to the provider's lessees. The lessor may also charge a monthly administrative fee not to exceed the maximum administrative fee authorized by the Commission, as indicated in Item 11 above.

FORM WRN-3
ESTABLISHED 08/2017

16. Listing of All Properties in North Carolina for which the Proposed Administrative Fee Applies:

UTILITY SERVICE AREAS

	Physical Address	City	County	Type of Service (Water and/or Sewer)	Supplier(s)
Property No. 1					
Property No. 2					
Property No. 3					
Property No. 4					
Property No. 5					
Property No. 6					
Property No. 7					
Property No. 8					
Property No. 9					
Property No. 10					
Property No. 11					
Property No. 12					
Property No. 13					
Property No. 14					

Property No. 15 ____

Property No. 16 ____

Property No. 17 ____

Property No. 18 ____

Property No. 19 ____

Property No. 20 ____

FORM WRN-3
ESTABLISHED 08/2017

16. Listing of All Properties in North Carolina for which the Proposed Administrative Fee Applies – Continued:

UTILITY SERVICE AREAS

	Physical Address	City	County	Type of Service (Water and/or Sewer)	Supplier(s)
Property No. 21					
Property No. 22					
Property No. 23					
Property No. 24					
Property No. 25					
Property No. 26					
Property No. 27					

Property No. 28 ______________________________

Property No. 29 ______________________________

Property No. 30 ______________________________

Property No. 31 ______________________________

Property No. 32 ______________________________

Property No. 33 ______________________________

Property No. 34 ______________________________

Property No. 35 ______________________________

Property No. 36 ______________________________

Property No. 37 ______________________________

Property No. 38 ______________________________

Property No. 39 ______________________________

Property No. 40 ______________________________

(Attach supplemental sheets, if needed.)

FORM WRN-3
ESTABLISHED 08/2017

REQUIRED EXHIBITS AND INSTRUCTIONS

(1) Provide a current copy of the final executed agreements or contracts, if any, that the Applicant has entered into covering the provision of the billing and collection services to support the administrative fee requested. (The agreements/contracts should be signed by both the owner and the billing and collection company).

(2) If additional space is needed, supplementary sheets may be attached. If any section does not apply, write "not applicable".

(3) Line 1 - The entity's name listed on Line 1 should be the name of the current owner as certified by the Commission. Do not list the name of the billing and collection company or the management company.

(4) Line 2 - The business mailing address listed on Line 2 should be the mailing address for the current owner as certified by the Commission. Do not list the mailing address for the billing and collecting company or the management company.

(5) Line 12 – The docket number, which begins with "WRN-", as listed on the current schedule of administrative fee for the single-family dwellings in North Carolina, should be included on this line.

(6) The notification should be signed by the owner of the properties, not the billing and collection company.

(7) Pursuant to NCUC Rule R18-6(b), the owner of single-family dwellings may increase its administrative fee by filing this notification of revised fee with the Commission. The fee proposed on this notification will become effective on fourteen (14) days' notice after the date the notification was filed with the Commission, unless the rates are suspended or disapproved by Commission Order issued within 14 days of the filing of this notification.

(8) Electronic filing is available at www.ncuc.net for application submittal or mail one (1) original application with required exhibits and original **notarized signature**, plus three (3) additional collated copies to:

USPS Address:	OR	Overnight Delivery at Street Address:
Chief Clerk's Office		Chief Clerk's Office
North Carolina Utilities Commission		North Carolina Utilities Commission
4325 Mail Service Center		430 North Salisbury Street
Raleigh, North Carolina 27699-4300		Raleigh, North Carolina 27603-5918

(9) Provide a self-addressed stamped envelope, plus an additional copy of the application, if a file-stamped copy is requested by the Applicant.

(10) **Questions** - For any questions concerning this notification, please contact:

The Public Staff – North Carolina Utilities Commission, Water Division at 919-733-5610.

SIGNATURE

Application shall be signed and verified by the Applicant.

____
Signature

____
Typed or Printed Name

____
Date

(Typed or Printed Name) ____
Personally appearing before me and, being first duly sworn, says that the information contained in this application and in the exhibits attached hereto are true to the best of his/her knowledge and belief.
Subscribed and sworn before me this the _______ day of ______________________, 20____

____
Signature of Notary Public

____
Name of Notary Public – Typed or Printed
My Commission Expires: _____________

FORM WRN-2
ESTABLISHED 08/2017

APPENDIX D

DOCKET NO. WRN-______Sub____

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
ANNUAL UPDATE OF UTILITY SERVICE AREAS FOR SINGLE-FAMILY DWELLINGS CHARGING FOR WATER AND/OR SEWER SERVICE PURSUANT TO G.S. 62-110(G)

ANNUAL UPDATE IS DUE APRIL 30th EACH YEAR

ENTITY

1. Name of Owner: ____
2. Business Mailing Address of Owner: ______________________________________
3. City and State: ____ Zip Code: _______
4. Business Telephone: ______________________ Business Fax: ____________________
5. Business Email: ____
6. Person to Contact Concerning this Annual Update (Name, Telephone, and Email):
____

CONTACT INFORMATION

NAME ADDRESS TELEPHONE

7. Management Company: ____________ ____________ ________
8. Complaints or Billing: ____________ ____________ ________
9. Emergency Services: ____________ ____________ ________
10. Filing/Payment of Regulatory Fees to NCUC: ____________ ____________ ________

PRESENT AUTHORIZED ADMINISTRATIVE FEE

11. Monthly Administrative Fee: ________________________

CHANGES IN THE NUMBER OF PROPERTIES THROUGH MARCH 31ST

12. Total Number of Single-Family Dwellings Previously Reported: ____________
13. Total Number of Single-Family Dwellings Added: ______ (Please list the addresses on Line 16.)
14. Total Number of Single-Family Dwellings Sold: ________ (Please list the addresses on Line 17.)
15. Total Current Number of Dwellings (Line 12 + Line 13 - Line 14): _____ on March 31, ________.
    (year)

FORM WRN-2
ESTABLISHED 08/2017

11. **Listing of All Newly Added Properties in North Carolina for which an Administrative Fee Is Applied:**

UTILITY SERVICE AREAS ADDED

	Physical Address	City	County	Type of Service (Water and/or Sewer)	Supplier(s)
Property No. 1					
Property No. 2					
Property No. 3					
Property No. 4					
Property No. 5					
Property No. 6					
Property No. 7					
Property No. 8					
Property No. 9					
Property No. 10					
Property No. 11					
Property No. 12					
Property No. 13					
Property No. 14					

Property No. 15 ____

Property No. 16 ____

Property No. 17 ____

Property No. 18 ____

Property No. 19 ____

Property No. 20 ____

FORM WRN-2
ESTABLISHED 08/2017

16. Listing of All Newly Added Properties in North Carolina for which an Administrative Fee Is Applied - Continued:

UTILITY SERVICE AREAS ADDED

	Physical Address	City	County	Type of Service (Water and/or Sewer)	Supplier(s)
Property No. 21					
Property No. 22					
Property No. 23					
Property No. 24					
Property No. 25					
Property No. 26					

Property No. 27 ____________________

Property No. 28 ____________________

Property No. 29 ____________________

Property No. 30 ____________________

Property No. 31 ____________________

Property No. 32 ____________________

Property No. 33 ____________________

Property No. 34 ____________________

Property No. 35 ____________________

Property No. 36 ____________________

Property No. 37 ____________________

Property No. 38 ____________________

Property No. 39 ____________________

Property No. 40 ____________________

(Attach supplemental sheets, if needed.)

FORM WRN-2
ESTABLISHED 08/2017

17. Listing of All North Carolina Properties Sold During the Annual Update Period:

UTILITY SERVICE AREAS SOLD

	Physical Address	City	County	Type of Service (Water and/or Sewer)	Supplier(s)
Property No. 1					
Property No. 2					
Property No. 3					
Property No. 4					
Property No. 5					
Property No. 6					
Property No. 7					
Property No. 8					
Property No. 9					
Property No. 10					
Property No. 11					
Property No. 12					

Property No. 13 ____________________

Property No. 14 ____________________

Property No. 15 ____________________

Property No. 16 ____________________

Property No. 17 ____________________

Property No. 18 ____________________

Property No. 19 ____________________

Property No. 20 ____________________

(Attach supplemental sheets, if needed.)

FORM WRN-2
ESTABLISHED 08/2017

REQUIRED EXHIBITS

(1) Exhibit A: A copy of the warranty deeds showing that the Entity has ownership of all the properties listed in Item 16. **(Grantee on the Deed must match owner's name on Line 1 of the update.)**

(2) Exhibit B: Vicinity maps (i.e., Google Maps) showing the locations of the newly added single-family dwellings listed in Item 16 in sufficient detail for someone not familiar with the counties to locate the dwellings.

(3) Exhibit C: Provide a current copy of the final executed agreements or contracts, if any, that the Entity has entered into covering the provision of the billing and collection services for the newly added dwellings. (The agreements/contracts need to be signed by both the owner and the billing and collection company).

FILING INSTRUCTIONS

(4) If additional space is needed, supplementary sheets may be attached. If any section does not apply, write "not applicable".

(5) Annual update period is from **April 1st of prior year to March 31st of current year**. For the company's first annual update, the annual update period is from the Order date for which the company's Certificate of Authority was granted by the Commission to the following March 31st.

(6) Electronic filing is available at www.ncuc.net for annual update submittal or mail one (1) original update form with required exhibits and **original notarized signature**, 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

(7) Provide a self-addressed stamped envelope, plus an additional copy of the application, if a file-stamped copy is requested by the Applicant.

SIGNATURE

Update shall be signed and verified by the Owner (Entity).

____
Signature

____
Typed or Printed Name

____
Date

(Typed or Printed Name) ____________________________________
Personally appearing before me and, being first duly sworn, says that the information contained in this
application and in the exhibits attached hereto are true to the best of his/her knowledge and belief.
Subscribed and sworn before me this the ______ day of __________, 20__________.

____
Signature of Notary Public

____
Name of Notary Public – Typed or Printed

My Commission Expires: ____________

APPENDIX E

Additional Modifications to Rules R18-6 and R18-7 to Allow for a Returned Check Charge

Rule R18-6. Rates. [Modify by adding new Subsection (d) and changing existing Subsections (d) to (e).]

. . .

<u>(d) The provider may impose a returned check charge, not to exceed the maximum authorized by G.S. 25-3-506, for a check on which payment has been refused by the payor bank because of insufficient funds or because the lessee did not have an account at that bank.</u>

~~(d)~~ <u>(e)</u> No provider shall charge or collect any greater or lesser compensation for the costs of providing water or sewer service than the rates approved by the Commission.

Rule R18-7. Disconnection; billing procedure; meter reading. [Modify by adding new Subsection (b) and renumber existing Subsections (b-f) to (c-g).]

(a) No charge for connection or disconnection, charge for late payment, or similar charge in addition to the rate specified in Rule R18-6 shall be allowed.

(b) A returned check charge as provided for in Rule R18-6(d) shall be allowed.

~~(b)~~ (c) No provider may disconnect water or sewer service for nonpayment.

~~(c)~~ (d) Bills shall be rendered at least monthly.

~~(d)~~ (e) The date after which a bill for water or sewer utility service is due, or the past due after date, shall be disclosed on the bill and shall not be less than twenty-five (25) days after the billing date.

~~(e)~~ (f) A provider shall not bill for or attempt to collect for excess usage resulting from a plumbing malfunction or other condition which is not known to the lessee ~~tenant~~ or which has been reported to the provider.

~~(f)~~ (g) Every provider shall provide to each customer at the time the lease agreement is signed, and shall maintain in its business office, in public view, near the place where payments are received, the following: . . .

APPENDIX E
(CLEAN)

Additional Modifications to Rules R18-6 and R18-7 to Allow for a Returned Check Charge

Rule R18-6. Rates.

. . .

(d) The provider may impose a returned check charge, not to exceed the maximum authorized by G.S. 25-3-506, for a check on which payment has been refused by the payor bank because of insufficient funds or because the lessee did not have an account at that bank.

(e) No provider shall charge or collect any greater or lesser compensation for the costs of providing water or sewer service than the rates approved by the Commission.

Rule R18-7. Disconnection; billing procedure; meter reading.

(a) No charge for connection or disconnection, charge for late payment, or similar charge in addition to the rate specified in Rule R18-6 shall be allowed.

(b) A returned check charge as provided for in Rule R18-6(d) shall be allowed.

(c) No provider may disconnect water or sewer service for nonpayment.

(d) Bills shall be rendered at least monthly.

(e) The date after which a bill for water Or sewer utility service is due, or the past due after date, shall be disclosed on the bill and shall not be less than twenty-five (25) days after the billing date.

(f) A provider shall not bill for or attempt to collect for excess usage resulting from a plumbing malfunction or other condition which is not known to the lessee or which has been reported to the provider.

(g) Every provider shall provide to each customer at the time the lease agreement is signed, and shall maintain in its business office, in public view, near the place where payments are received, the following: ...

DOCKET NO. E-22, SUB 545

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 G.S. 62-133.9 and Commission Rule R8-69	))))))	ORDER APPROVING DSM/EE RIDER AND REQUIRING FILING OF PROPOSED CUSTOMER NOTICE

HEARD: Monday, November 6, 2017, at 1:40 p.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Chairman Edward S. Finley, Jr.; Commissioners Bryan E. Beatty, Jerry C. Dockham, James G. Patterson, Lyons Gray and Daniel G. Clodfelter

APPEARANCES:

For Dominion Energy North Carolina:

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

For the Using and Consuming Public:

Heather D. Fennell, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: General Statute 62-133.9(d) authorizes the North Carolina Utilities Commission (Commission) to approve an annual rider to the rates of electric utilities to recover all reasonable and prudent costs incurred for the adoption and implementation of new demand-side management and energy efficiency (DSM/EE) programs. In accordance with Commission Rule R8-69(b), such rider consists of the utility's reasonable and appropriate estimate of expenses expected to be incurred during the rate period and a DSM/EE experience modification factor (DSM/EE EMF) rider to collect or refund the difference between the utility's actual reasonable and prudent costs incurred during the test period and actual revenues realized during the test period under the DSM/EE rider then in effect. The Commission is also authorized to award incentives to electric utilities for adopting and implementing new DSM/EE programs, including appropriate rewards based on the sharing of savings achieved by the programs. These utility incentives are included in the utility's reasonable and appropriate estimate of expenses expected to be incurred during the rate period and DSM/EE EMF riders described above.

Further, Commission Rule R8-69(b) provides that the Commission will each year conduct a proceeding for each electric utility to establish an annual DSM/EE rider to recover DSM/EE related costs and utility incentives. Commission Rule R8-69(e) provides that the annual DSM/EE cost recovery rider hearing for each public utility will be scheduled as soon as practicable after the annual fuel and fuel-related charge adjustment proceeding held by the Commission for the electric public utility under Commission Rule R8-55.

On August 15, 2017, 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 Program Performance Incentive.

Pertinent Proceedings in Prior Dockets

The Commission most recently approved DENC's recovery of its reasonable and prudent DSM/EE costs and utility incentives by Order issued on December 19, 2016, in Docket No. E-22, Sub 536 (2016 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 also 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 utility incentive approved for inclusion in its DSM/EE and DSM/EE EMF riders from a Program Performance Incentive to a Portfolio Performance Incentive (PPI).

On May 22, 2017, in Docket No. E-22, Sub 464, the Commission issued its Order Approving Revised Cost Recovery and Incentive Mechanism (2017 Mechanism). The 2017 Mechanism became effective as of May 22, 2017, for projected costs and utility incentives beginning January 1, 2018, and for true-ups of costs and utility incentives beginning January 1, 2017, and is used in this proceeding to calculate the Rider C billing rates related to DSM and EE measures projected to be installed or implemented for Vintage Year 2018.

Proceedings in the Present Docket

On August 15, 2017, 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, Melba L. Lyons, 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 then in effect.

On August 24, 2017, DENC filed corrections at page 5 of witness Stephens' direct testimony to the projected typical customer bill impacts of proposed Riders C and CE.

On August 30, 2017, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. Pursuant to this Order, the Commission established deadlines for the filing of petitions to intervene, intervenor testimony and exhibits, and Company rebuttal testimony and exhibits, scheduled a hearing to be held on Monday, November 6, 2017, in Raleigh, North Carolina, and required DENC to publish a customer notice.

The intervention and participation in this docket by the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). No other parties intervened or presented testimony in this docket.

On October 23, 2017, the Public Staff filed the affidavit and exhibit of Michael C. Maness, Director, Accounting Division, and the testimony of Jack L. Floyd, Engineer, Electric Division.

On October 25, 2017, DENC filed its Affidavit of Publication indicating that it had provided notice in newspapers of general circulation.

On October 31, 2017, DENC filed the rebuttal testimony of Deanna R. Kesler and the rebuttal testimony and accompanying exhibit of Alan J. Moore.

On November 1, 2017, the Public Staff and DENC filed a Joint Motion to excuse witnesses from appearing at the November 6, 2017, 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 3, 2017, the Commission issued an Order granting the Joint Motion.

On November 3, 2017, the Public Staff filed a letter with the Commission stating that based on its detailed review of the costs of the portfolio of DSM/EE programs of DENC incurred during the 12-month test period ended December 31, 2016, that the revised DSM/EE EMF revenue requirement of $201,456 set forth in Company Exhibit No. AJM-1, Rebuttal Schedule 2, and the Company-proposed Rider C and Rider CE billing rates set forth in the Company's August, 15, 2017 filing in this proceeding be approved.

On November 6, 2017, the Commission held the hearing as scheduled. No public witnesses appeared at the hearing.

On December 14, 2017, DENC and the Public Staff filed a Joint Proposed Order.

Based upon DENC's Application, the testimony, affidavits, and exhibits received into evidence at the hearing, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Virginia Electric and Power Company (VEPCO) operates in the State of North Carolina as DENC. VEPCO, d/b/a DENC, is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public for compensation in North Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility.

2. DENC is lawfully before the Commission based upon its Application filed pursuant to G.S. 62-133.9 and Commission Rule R8-69.

3. Pursuant to the 2017 Mechanism, the rate period for purposes of this proceeding is the 12-month period of January 1, 2018, through December 31, 2018.

4. Pursuant to the 2017 Mechanism, the test period for purposes of this proceeding is the 12-month period of January 1, 2016, through December 31, 2016.

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 II DSM/EE programs: Non-residential Energy Audit Program, Non-residential Duct Testing and Sealing Program, Residential Home Energy Check-Up Program, Residential Duct Sealing Program, Residential Heat Pump Tune-Up Program, and Residential Heat Pump Upgrade Program; (c) Phase III DSM/EE programs: Non-residential Lighting Systems and Controls Program, Non-residential Heating & Cooling Efficiency Program, and Non-residential Window Film Program; (d) the Phase IV Income and Age Qualifying Home Improvement

Program; (e) the Phase V Small Business Improvement Program, the North Carolina-only Residential Retail LED Lighting program; and the proposed Phase VI Non-Residential Prescriptive Program.[1]

6. In addition, DENC has requested test period recovery of costs and utility incentives related to the following approved DSM/EE Programs: Residential Low Income Program, Commercial Lighting Program, Commercial HVAC Program, Air Conditioner Cycling Program, Residential Heat Pump Tune Up Program, Residential Heat Pump Upgrade Program, Residential Home Energy Check Up Program, Residential Duct Sealing Program, Non-residential Duct Testing and Sealing Program, Non-residential Energy Audit Program, Non-residential Heating and Cooling Efficiency Program, Non-residential Lighting Systems and Controls Program, Residential Lighting Program, Non-residential Window Film Program, Small Business Improvement Program, North Carolina-only Residential LED Lighting Program, and the Residential Income and Age Qualifying Home Improvement Program.

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, as revised in its October 31, 2017, rebuttal filing. 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 $3,542,469, 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, is $201,456, as set forth in its October 31, 2017, rebuttal filing.

11. Rider C as proposed in the Application is reasonable and appropriate, and consists of the following customer class billing factors: Residential – 0.113 ¢/kWh; Small General Service and Public Authority – 0.146 ¢/kWh; Large General Service – 0.112 ¢/kWh; and no charge for 6VP, NS, Outdoor Lighting, or Traffic Lighting. It is reasonable and appropriate for Rider C to become effective for usage on and after January 1, 2018. The impact of the Regulatory Fee is too small to change these billing factors.

12. Rider CE as proposed in the Application and in the October 31, 2017, rebuttal filing is reasonable and appropriate, and consists of the following increments to customer class billing factors: Residential – 0.007 ¢/kWh; Small General Service and Public Authority – 0.008 ¢/kWh;

[1] This program was approved by the Commission's Order in Docket No. E-22, Sub 543 on October 16, 2017.

Large General Service – 0.006 ¢/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 January 1, 2018. The impact of the Regulatory Fee is too small to change these billing factors.

13. DENC requested the recovery of NLR in the amount of $500,942 and PPI in the amount of $270,150 for the test period, and a projected PPI of $313,603, but no NLR, for the rate period. DENC's calculation and proposed recovery of NLR and 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 Lyons 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 the 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 2016 and earlier vintages are sufficient to consider those vintage years complete for all programs operating in those years.

17. The Public Staff's suggested corrections to input data into the algorithms used to calculate the vintage year savings for the Residential Home Energy Check Up, Non-Residential Energy Audit Program, Non-Residential Duct Testing and Sealing Program, Non-Residential Heating and Cooling Efficiency Program, and the Non-Residential Lighting Systems and Controls Program are reasonable and should be made by the Company.

18. It is reasonable for the Company to continue its current practice regarding changes or corrections to EM&V data by recalculating the savings with the corrected data and adjusting the savings in future years to account for the changes or corrections in the input data. Therefore, it is appropriate for DENC's future EM&V reports to clearly identify any corrections to previous vintage year savings separate from the savings associated with the test year that is the subject of the EM&V report.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

These findings of fact are essentially informational, procedural, and jurisdictional in nature and are uncontroverted. The rate period and test period used by DENC are consistent with the 2017 Mechanism approved by the Commission in Docket No. E-22, Sub 464, and with Commission Rule R8-69.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 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, the rebuttal testimony and exhibits of witness Moore, and the affidavit of Public Staff witness Maness and testimony of Public Staff witness Floyd.

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 II DSM/EE programs: Non-residential Energy Audit Program, Non-residential Duct Testing & Sealing Program, Residential Home Energy Check-Up Program, Residential Duct Sealing Program, Residential Heat Pump Tune-Up Program, and Residential Heat Pump Upgrade Program; (c) 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; (d) the Phase IV Income and Age Qualifying Home Improvement Program; (e) the Phase V Small Business Improvement Program, the Residential North Carolina-only Retail LED Lighting program; and the proposed Phase VI Non-Residential Prescriptive Program.[1] 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-up for the Phase I, Phase II, Phase III, Phase IV, Phase V, and proposed Phase VI programs during the January 1, 2016, to December 31, 2016, test period, incorporating actual costs, NLR, and PPI. As mentioned in the testimony of Company witness Hubbard, the Phase I programs included Residential Low Income, Residential Lighting, Commercial HVAC Upgrade, and Commercial Lighting (all now closed) as well as the ongoing Residential Air Conditioner Cycling program.

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 Floyd 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 2018 for (1) the active DSM and EE programs that are not subject to closure or suspension, and (2) the Air Conditioner Cycling Program. As shown on her exhibits, all programs have TRC results above 1.0, indicating cost effectiveness, with the exception of the Residential Income and Age Qualifying Home Improvement Program and the Small Business Improvement Program. All programs have UCT results above 1.0, with the exception of the Residential Income and Age Qualifying Home Improvement Program, Small Business Improvement Program, and the AC Cycling Program.

Company witness Hubbard also testified that DENC has not projected NLR for the rate period, consistent with its approach in the 2014, 2015, and 2016 DSM/EE cost recovery riders. He proposed to true-up NLR in future proceedings. Witness Hubbard also stated that the Company had not identified any found revenues. The Commission finds the DENC approach to recovery of NLR, and the lack of found revenues, to be reasonable in this proceeding. Public Staff witness

[1] This program was approved by the Commission's Order in Docket No. E-22, Sub 543 on October 16, 2017.

Maness testified that in his opinion, the Company had generally calculated its proposed Rider C DSM/EE billing rates, which include these simplified approaches, in a manner consistent with G.S. 62-133.9, Commission Rule R8-69, and the 2015 and 2017 Mechanisms.

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 and rebuttal 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, Lyons, and Stephens; the rebuttal testimony and exhibit of witness Moore; and the affidavit and exhibit 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 Lyons allocated the common costs among the DSM/EE programs. She 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 Lyons 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 Lyons, 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 approved in the Company's most recent general rate case (Docket 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 Lyons. 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 Revised and 2017 Mechanisms, 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, 2016, 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.

In rebuttal testimony filed on October 31, 2017, DENC witness Moore stated that through discovery, the Company had discovered that the months of February and March 2016 included erroneous charges for the Air Conditioning Cycling program's Plant in Service balance that were subsequently adjusted out in May 2016. However, the February and March 2016 monthly balances used in the originally submitted Rider CE revenue requirement had not been adjusted to reflect this correction. Making these final adjustments reduced the Company's proposed Rider CE revenue requirement by $974, to $201,456. Witness Moore further testified that the Company had determined that the Rider CE billing rates calculated based upon the rebuttal Rider CE revenue requirement did not change from the Rider CE rates included in the Company's direct filing.

On November 3, 2017, the Public Staff filed a letter with the Commission stating that based on its detailed review of the costs of the portfolio of DSM/EE programs of DENC incurred during the 12-month test period ended December 31, 2016, the Public Staff did not recommend any further adjustments to those costs, and recommended that the revised DSM/EE EMF revenue requirement of $201,456 set forth in Company Exhibit No. AJM-1, Rebuttal Schedule 2, and the Company-proposed Rider C and Rider CE billing rates set forth in the Company's August 15, 2017 filing, be approved.

On Exhibit AJM-1, Schedule 1, page 1, as filed on August 15, 2017, witness Moore calculated DENC's requested North Carolina retail rate period (January 1, 2018, through December 31, 2018) revenue requirement (for Rider C) as follows:

1.	Operating Expense	$3,091,006
2.	Capital Cost	$ 137,860
3.	NLR	$ 0
4.	PPI	$ 313,603
5.	Total	$3,542,469

ELECTRIC – ADJUSTMENTS OF RATES/CHARGES

On Company Exhibit AJM-1, Rebuttal Schedule 2, as filed on October 31, 2017, witness Moore calculated DENC's requested North Carolina retail test period DSM/EE EMF (January 1, 2016, through December 31, 2016) revenue requirement (for Rider CE) as follows:

Operating expenses	$ 2,569,642
Capital costs (depr, rate base, prop. taxes)	$ 123,665
NLR	$ 500,943
PPI	$ 270,149
Test period Rider C revenues	($ 3,222,514)
Net revenue requirement subtotal	$ 241,885
Carrying costs	($ 40,429)
Interest on EMF refund	($ 0)
Total Rider CE revenue requirement	$ 201,456

Company witness Lyons, in Exhibit MLL-1, Schedule 3, pages 2 and 4, allocated the Rider C and initial Rider CE revenue requirement among the North Carolina retail customer classes. The results of her allocation for Rider C are shown below and set forth on Company Exhibit DAS-1, Schedule 1, page 9 of 10. Using the same methodology as used by witness Lyons, the Company allocated the initial Rider CE revenue requirement of $202,430 as also shown below and set forth on Company Exhibit DAS-1, Schedule 4, page 1 of 2:

Rate Class	Rider C Amount	Rider CE Amount
Residential	$ 1,791,897	$ 104,662
SGS Co & Muni	$ 1,203,229	$ 67,200
LGS	$ 547,343	$ 30,569
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. However, witness Moore testified that the Rider CE rates supported by his rebuttal testimony did not change from those initially filed. Thus, the Company did not file updated Rider CE calculations or tariff sheets.

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 Schedule 4, page 2, and the rebuttal testimony and exhibits filed by witness Moore support the following customer class Rider C and Rider CE billing factors to be put into effect on January 1, 2018:

CUSTOMER CLASS	RIDER C RATE (cents/kWh)	RIDER CE RATE (cents/kWh)
Residential	0.113	0.007
Small General Service & Public Authority	0.146	0.008
Large General Service	0.112	0.006
6VP	0.000	0.000
NS	0.000	0.000
Outdoor Lighting	0.000	0.000
Traffic Lighting	0.000	0.000

The billing factors are unchanged by 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 direct and rebuttal filings, 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.

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 2016 Order, Company witness Bates provided information on consumer education and awareness initiatives conducted by VEPCO'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. The EC department relies heavily on online tools for general education; their web pages received around 300,000 visits in the test period, and the web pages for the implementation contractor, Honeywell, also received over 116,000 visits. Other general education and awareness tools included use of social media and airing of stories on local television stations.

The Public Staff did not oppose DENC's consumer education and awareness activities or costs.

Based on the evidence presented above and all the information in the record, the Commission finds and concludes that DENC's consumer education and awareness activities and costs are reasonable for purposes of this proceeding. Further, the Commission finds and concludes that the Company shall continue to include a list of consumer education and awareness activities and the volume of activity associated with each during the test period in its annual DSM/EE cost recovery filing.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 16-18

The evidence for these findings of fact is contained in the direct and rebuttal testimony of Company witnesses Kesler, the EM&V report filed by DENC on May 1, 2017, in Docket No. E-22, Sub 536, and the testimony of Public Staff witness Floyd.

DENC witness Kesler testified that the Company had included a chronology of changes to program attributes in its 2017 EM&V report for calendar year 2016, as recommended by the Public Staff. Witness Kesler noted that DENC plans to file its next EM&V report on May 1, 2018, to match filing requirements in Virginia.

Public Staff witness Floyd testified that he had reviewed DENC's 2017 EM&V report for calendar year 2016 with the assistance of GDS Associates. He was of the opinion that the 2017 EM&V report for calendar year 2016 complied with previous Commission orders pertaining to EM&V, although during his review he concluded that several of the algorithms used to calculate vintage year savings contained input data that were either misapplied or input incorrectly in the calculation itself. Those inputs were related to the temperature differences related to low flow showerhead, waste heat factors for non-residential lighting applications, and full load heating hours of heat pumps. He further testified that by correcting these inputs, the savings associated with vintage year 2016 would likely need to be adjusted in the next rider proceeding. Witness Floyd also testified, however, that DENC's third party EM&V evaluator had acknowledged that corrections needed to be made, and that the Company proposed to make them in the next EM&V filing in the spring of 2018.

Further, Public Staff witness Floyd recommended that, although there were no issues with the Company's current practice regarding changes to its EM&V algorithms, it would be appropriate for DENC's future EM&V reports to clearly identify any corrections to previous vintage year savings separate from the savings associated with the test year that is the subject of the EM&V report. Specifically, witness Floyd recommended that the evaluator may report the total savings for the test year in the EM&V report, but should also separately identify any changes or corrections.

In response to witness Floyd's recommendations, DENC witness Kesler noted that the Company agreed with witness Floyd's recommended EM&V calculation corrections, and would file such corrections to the 2017 EM&V Report as soon as possible but no later than December 31, 2017. Additionally, witness Kesler stated that the corrected values and associated updates to the EM&V process would also be reflected in the Company's next annual EM&V report, to be filed on or before May 1, 2018, with the Commission, as well as in future DENC DSM cost recovery and program application filings. Company witness Kesler also testified that the Company generally agreed with witness Floyd's recommendations on presentation of future EM&V corrections and changes, and that the Company and its third party evaluator would work with the Public Staff to develop a process going forward for implementing corrections and changes to the EM&V process and a reporting function to be implemented starting with the Company's 2018 EM&V Report.

The Public Staff also filed a letter on November 3, 2017, stating that DENC is appropriately incorporating the results of its EM&V efforts into the DSM/EE rider calculations, and that the EM&V for vintage year 2016 and earlier vintages could be considered complete.

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.

The Commission also accepts the recommendations of Public Staff witness Floyd on future reporting processes used by the Company for implementing corrections and changes to the EM&V reporting process. The Commission concludes that DENC should file any outstanding corrections to its 2017 EM&V Report with the EM&V report the Company plans to file in the spring of 2018 for Year 2017, and work with the Public Staff to develop a process going forward for implementing corrections and changes to the EM&V process and a reporting function to be implemented starting with the Company's 2018 EM&V Report.

IT IS, THEREFORE, ORDERED as follows:

1. That the appropriate annual DSM/EE rider, Rider C, to become effective on and after January 1, 2018, consists of the following customer class billing factor increments (including Regulatory Fee): Residential – 0.113 ¢/kWh; Small General Service and Public Authority – 0.146 ¢/kWh; Large General Service – 0.112 ¢/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 January 1, 2018, consists of the following customer class increment billing factors (including Regulatory Fee): Residential – 0.007 ¢/kWh; Small General Service and Public Authority – 0.008 ¢/kWh; Large General Service – 0.006 ¢/kWh; and no increment or 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 No. E-22, Sub 544, and the Company shall file such notice for Commission approval as soon as practicable, but not later than three working days after the date of this Order.

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.

6. That DENC shall file any outstanding corrections to its 2017 EM&V Report with its EM&V report to be filed in the spring of 2018 for Year 2017, and shall work with the Public Staff to develop a process going forward for implementing corrections and changes to the EM&V process and a reporting function to be implemented starting with the Company's 2018 EM&V Report.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of December, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

DOCKET NO. E-2, SUB 1146

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC	)	
Pursuant to G.S. 62-133.2 and	)	ORDER APPROVING FUEL
NCUC Rule R8-55 Relating to Fuel	)	CHARGE ADJUSTMENT
and Fuel-Related Charge Adjustments	)	
for Electric Utilities	)	

HEARD: Tuesday, September 19, 2017, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, Commissioner Bryan E. Beatty, Commissioner ToNola D. Brown-Bland, Commissioner Jerry C. Dockham, Commissioner James G. Patterson, Commissioner Lyons Gray and Commissioner Daniel G. Clodfelter

APPEARANCES:

For Duke Energy Progress, LLC:

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Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For Carolina Utility Customer Association, Inc.

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

For North Carolina Sustainable Energy Association:

Peter H. Ledford, Esq., 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For Carolinas Industrial Group for Fair Utility Rates II:

Adam Olls, Esq., Warren K. Hicks, Esq., Bailey & Dixon, L.L.P., Post Office Box 1351, Raleigh, North Carolina 27602

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney, Robert B. Josey, Jr., Staff Attorney, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On June 21, 2017, Duke Energy Progress, LLC (Duke Energy Progress, DEP, or the Company), filed an application pursuant to G.S. 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 Kendra A. Ward, Brett Phipps, Joseph A. Miller, Jr., T. Preston Gillespie, Jr., and Kenneth D. Church.

Petitions to intervene were filed by the North Carolina Sustainable Energy Association (NCSEA) on July 6, 2017, by Carolina Industrial Group for Fair Utility Rates II (CIGFUR) on June 30, 2017, and by Carolina Utility Customers Association, Inc. (CUCA) on July 11, 2017. The Commission granted CIGFUR's petition to intervene on July 5, 2017, NCSEA's petition to intervene on July 10, 2017, and CUCA's petition to intervene on July 13, 2017.

On July 6, 2017, the Commission entered an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. That Order provided that, among other things, direct testimony of intervenors should be filed on September 5, 2017, that rebuttal testimony should be filed on September 13, 2017, and that a hearing on this matter would be held on September 19, 2017.

The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On September 15, 2017, DEP filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's procedural Order issued on July 6, 2017.

On September 6, 2017, DEP filed the supplemental testimony and revised exhibits of Kendra A. Ward.

On September 7, 2017, the Public Staff filed the testimony of Darlene P. Peedin and the testimony of Dustin R. Metz.

On September 7, 2017, the Commission issued an Order Requiring Publication of Second Public Notice due to the proposed rate changes reflected in the revised supplemental exhibits of witness Ward. Affidavits of publication for the second public notice were filed with the Commission on September 18, 2017 and September 21, 2017.

On September 13, 2017, DEP and the Public Staff filed a joint motion requesting that all witnesses be excused from appearance at the evidentiary hearing, representing that all parties to the proceeding had agreed to waive cross-examination of the witnesses. On September 15, 2017, the Commission granted the motion, excusing DEP witnesses Ward, Phipps, Miller, Gillespie, and Church, and Public Staff witnesses Peedin and Metz from appearing at the evidentiary hearing.

The case came on for hearing as scheduled on September 19, 2017. The prefiled direct and supplemental testimony of DEP's witnesses and the prefiled testimony of the Public Staff's witnesses were received into evidence. No other party presented witnesses, and no public witnesses appeared at the hearing.

The Public Staff and DEP filed a joint proposed order on October 24, 2017.

Based upon the Company's verified application, the testimony, affidavits, and exhibits received into evidence at the hearing, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Duke Energy 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 G.S. 62-133.2.

2. The test period for purposes of this proceeding is the 12 months ended March 31, 2017 (test period).

3. In its application and supplemental testimony in this proceeding, DEP requested a total increase of approximately $110 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 and over-recoveries experienced during the test period, with an overall net under-recovery of $33 million made up of a $42 million under-recovery from the Residential, Small General Service, Large General Service, and Lighting customer classes, partially offset by a $9 million over-recovery from the Medium General Service class:

4. The Company and the Public Staff agreed to remove $876,686 of replacement power costs incurred by the Company during an August 2016 outage at the Robinson Nuclear Station consistent with similar treatment in South Carolina. The Company's baseload plants were generally 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 Company's merger-related fuel savings for the test period as reported in Schedule 11 of the Company's Monthly Fuel Report are reasonable.

7. The test period per book system sales are 60,973,121 megawatt-hours (MWh). The test period per book system generation (net of auxiliary use and joint owner generation) and purchased power is 70,235,878 MWh and is categorized as follows:

Net Generation Type	MWh
Coal	11,114,200
Natural Gas, Oil and Biomass	22,074,423
Nuclear	29,033,303
Hydro – Conventional	339,751
Solar	188,088
Purchased Power – subject to economic dispatch or curtailment	3,896,948
Other Purchased Power	3,589,165
Total Net Generation (may not add to sum due to rounding)	70,235,878

8. The appropriate nuclear capacity factor for use in this proceeding is 92.6%.

9. The North Carolina retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 37,570,033 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	15,786,375
Small General Service	1,896,757
Medium General Service	11,162,395
Large General Service	8,347,370
Lighting	377,137
Total (may not add to sum due to rounding)	37,570,033

10. The projected billing period (December 2017-November 2018) sales for use in this proceeding are 62,163,816 MWh on a system basis and 37,526,498 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	15,667,933
Small General Service	1,808,399
Medium General Service	10,417,309
Large General Service	9,237,571
Lighting	395,287
Total (may not add to sum due to rounding)	37,526,498

11. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 68,022,851 MWh and is categorized as follows:

Generation Type	MWh
Coal	9,784,920
Gas Combustion Turbine (CT) and Combined Cycle (CC)	20,231,727
Nuclear	28,721,189
Hydro	598,023
Solar	282,714
Purchased Power	8,404,277
Total (may not add to sum due to rounding)	68,022,851

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 coal fuel price is $32.32/MWh.
B. The gas CT and CC fuel price is $28.71/MWh.
C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $23,900,904.
D. The total nuclear fuel price (including Joint Owners generation) is $7.14/MWh.
E. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared and the impact of House Bill 589, N.C. Sess. L. 2017-192), is $354,447,029.
F. System fuel expense recovered through intersystem sales is $79,089,672.

13. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $853,205,811.

14. The Company's appropriate North Carolina retail jurisdictional fuel and fuel-related expense under-collection for purposes of the EMF was $32,521,056, consisting of under-recoveries of $21,282,684; $1,023,834; $17,750,323 and $1,807,912, for the Residential, Small General Service, Large General Service, and Lighting classes, respectively, and an over-recovery of $9,343,696 for the Medium General Service class. The under-recovered amounts will be deferred until the 2018 fuel proceeding, without any recovery of interest by the Company.

15. The appropriate amount of interest on the Company's fuel and fuel-related cost over-collection for the North Carolina retail jurisdiction is $1,557,282 for the Medium General Service class.

16. The increase in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-2, Sub 1107 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.

17. 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: 2.179¢/kilowatt-hour (kWh) for the Residential class; 2.121¢/kWh for the Small General Service class; 2.356¢/kWh for the Medium General Service class; 2.417¢/kWh for the Large General Service class; and 1.657¢/kWh for the Lighting class.

18. The appropriate EMFs established in this proceeding, excluding the regulatory fee and deferring the under-recoveries until the 2018 fuel proceeding, are as follows: 0.000¢/kWh for the Residential class; 0.000¢/kWh for the Small General Service class; (0.084)¢/kWh for the Medium General Service class; 0.000¢/kWh for the Large General Service class; and 0.000¢/kWh for the Lighting class.

19. The appropriate EMF interest decrements established in this proceeding, excluding GRT and the regulatory fee and deferring the under-recoveries until 2018's fuel proceeding, are as follows: 0.000¢/kWh for the Residential class; 0.000¢/kWh for the Small General Service class; (0.014)¢/kWh for the Medium General Service class; 0.000¢/kWh for the Large General Service class; and 0.000¢/kWh for the Lighting class.

20. 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: 2.179¢/kWh for the Residential class; 2.121¢/kWh for the Small General Service class; 2.258¢/kWh for the Medium General Service class; 2.417¢/kWh for the Large General Service class; and 1.657¢/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

G.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, 2017.

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 Ward, 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 testimony of Company witnesses Gillespie and Miller and the testimony of Public Staff witnesses Peedin and 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 Gillespie 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 93.65% during the test period. This capacity factor, as well as the Company's 2-year average capacity factor of 92.34%, exceeded the five-year industry weighted average capacity factor of 88.9% for the period 2011-2015 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report.

Company witness Miller 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[1] 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 Miller 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 2011 through 2015:

[1] Derated hours are hours the unit operation was less than full capacity.

Generator Type	Measure	Review Period DEP Operational Results	2011-2015 NERC Average	Nbr of Units
Coal-Fired Test Period	EAF	91.1%	82.5%	446
	NCF	35.8%	60.5%	
	EFOR	3.8%	7.4%	
Coal-Fired Summer Peak	EAF	93.4%	n/a	n/a
Total CC Average	EAF	86.5%	84.6%	309
	NCF	77.0%	51.6%	
	EFOR	1.56%	5.8%	
Total CT Average	EAF	89.6%	87.0%	876
	SR	98.2%	97.8%	
Hydro	EAF	92.5%	81.9%	1,141

Company witness Miller 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 65% of the DEP fossil/hydro generation during the test period.

Public Staff witness Peedin testified that, in DEP's cost review proceeding in South Carolina, the Office of Regulatory Staff (ORS) proposed the adjustment to remove the South Carolina share of certain replacement costs incurred by the Company during an August 2016 unscheduled outage at the Robinson Nuclear Plant. DEP stipulated to the adjustment in South Carolina. Witness Peedin noted that North Carolina's share is $876,686, and DEP has agreed that it will not object to the disallowance of this amount for purposes of this proceeding.

Based upon the evidence in the record, the Commission concludes that the disallowance proposed by witness Peedin, and as agreed to by DEP, is appropriate. The Commission further concludes that DEP generally managed its baseload plants prudently and efficiently so as to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's revised fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A in 2008, and were in effect throughout the 12 months ending March 31, 2017. 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 Ward, Phipps, Miller, and Church.

Company witness Ward 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, coal, natural gas, and hydro; lower natural gas and coal prices; the capacity factors of its nuclear fleet; the combination of DEP's 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 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 decreased approximately 1%, from $80.74 per ton in the prior test period to $80.26 per ton in the test period. The Company's transportation costs increased approximately 17%, from $24.02 per ton in the prior test period to $28.03 per ton in the test period.

Witness Phipps stated that DEP's current coal burn projection for the billing period is 3.7 million tons compared to 4.7 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 $78.96 per ton for the billing period compared to $80.26 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 147 MMBtu, which is a decrease from the 170 MMBtu consumed during the test period. The current average forward Henry Hub price for the billing period is $3.01 per MMBtu, compared to $2.77 per MMBtu in the test period. Witness Phipps also testified that the Company's average price of gas purchased for the test period was $4.00 per MMBtu, compared to $4.10 per MMBtu in the prior test period, representing a decrease of 2%.

G.S. 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 Miller testified that the Company's fossil/hydro generation portfolio consists of 9,288 MW of generating capacity, 3,544 MW of which is coal-fired generation across three generating stations and a total of seven units. These units are equipped with emission control equipment, including selective catalytic reduction (SCR) equipment for removing nitrogen oxides (NOx), flue gas desulfurization (FGD or scrubber) equipment for removing sulfur dioxide (SO_2), and low NOx burners. This inventory of coal-fired assets with emission control equipment enhances DEP's ability to maintain current environmental compliance and concurrently utilize coal with increased sulfur content, thereby providing flexibility for DEP to procure the most cost-effective options for fuel supply.

Company witness Miller 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, and/or the level of emissions reduction required.

Company witness Church testified that DEP's nuclear fuel procurement practices involve computing near and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, requesting proposals from qualified suppliers, negotiating a portfolio of long-term contracts from diverse sources of supply, and monitoring deliveries against contract commitments. Witness Church explained that for uranium concentrates, conversion and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. He also stated that, throughout the industry, the initial delivery under new long-term contracts commonly occurs several years after contract execution. For this reason, DEP relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, DEP's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. He further stated that diversifying fuel suppliers reduces DEP's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEP generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

G.S. 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, estimated forced outages at generating units based on historical trends, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their customers.

No party presented or elicited 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 direct 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. 6

The evidence supporting this finding of fact is contained in the testimony of Company witness Phipps.

According to witness Phipps, during September 2016, the Utilities met the guaranteed merger savings target of $721.8 million established pursuant to both the merger agreement between Duke Energy and Progress Energy, Inc., and the merger agreement between Duke Energy and Piedmont Natural Gas Company, Inc. The combined merger savings through September 2016 totaled $723 million, of which DEP's North Carolina share was $183 million.

Based on the evidence presented by DEP, and noting the absence of evidence presented to the contrary by any other party, the Commission finds and concludes that the Company's merger-related fuel savings for the test period are reasonable.

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 Ward.

According to the exhibits sponsored by Company witness Ward, the test period per book system sales were 60,973,121 MWh, and test period per book system generation and purchased power amounted to 70,235,878 MWh (net of auxiliary use and joint owner generation). The test period per book system generation and purchased power are categorized as follows (Ward Exhibit 6):

Net Generation Type	MWh
Coal	11,114,200
Natural Gas, Oil and Biomass	22,074,423
Nuclear	29,033,303
Hydro – Conventional	339,751
Solar	188,088
Purchased Power – subject to economic dispatch or curtailment	3,896,948
Other Purchased Power	3,589,165
Total Net Generation (may not add to sum due to rounding)	70,235,878

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 Ward'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 60,973,121 MWh and system generation and purchased power of 70,235,878 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 Gillespie 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 92.6% 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 2017-2018 billing period. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 88.9% for the period 2011-2015 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 92.6% 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 92.6% nuclear capacity factor, and its associated generation of 28,721,189 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 Ward.

On her Exhibit 4, Company witness Ward set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 37,570,033 MWh, comprised of Residential class sales of 15,786,375 MWh, Small General Service sales of 1,896,757 MWh, Medium General Service sales of 11,162,395 MWh, Large General Service sales 8,347,370 MWh, and Lighting class sales of 377,137 MWh.

Witness Ward 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 Ward Exhibit 2, Schedule 1, is 62,163,816 MWh. The projected level of generation and purchased power used was 68,022,851 MWh (calculated using the 92.6% capacity factor found reasonable and appropriate above), and was broken down by witness Ward as follows, as set forth on that same schedule:

Generation Type	MWh
Coal	9,784,920
Gas Combustion Turbine and Combined Cycle	20,231,727
Nuclear	28,721,189
Hydro	598,023
Solar	282,714
Purchased Power	8,404,277
Total (may not add to sum due to rounding)	68,022,851

As part of her Workpaper 7, Company witness Ward 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	15,667,933
Small General Service	1,808,399
Medium General Service	10,417,309
Large General Service	9,237,571
Lighting	395,287
Total (may not add to sum due to rounding)	37,526,498

These class totals were used in Revised Ward 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. 12

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses Ward and Phipps and the testimony of Public Staff witness Metz.

In her Revised Exhibit 2, Schedule 1, Company witness Ward 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 affidavit, 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, in combination with the testimony of Public Staff witness Peedin, are reasonable and in accordance with the requirements of G.S. 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 Ward 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 Ward and the testimony of Public Staff witness Metz.

According to Revised Ward Exhibit 2, Schedule 1, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $853,205,811. 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 $853,205,811 is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 14-20

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Ward, the testimony of Public Staff witnesses Peedin and Metz.

Company witness Ward presented DEP's original fuel and fuel-related expense over(under) collection and prospective fuel and fuel-related cost factors. Company witness Ward's supplemental 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, EMFs and the EMF interest along with revised exhibits and work papers. Public Staff witness Peedin testified that the Public Staff proposed to disallow the North Carolina retail amount of $876,686 in replacement power costs associated with an outage in August 2016 at the Robinson Nuclear Plant. Of the total $876,686 adjustment, $257,907 is allocable to the medium general service class and will be added to the over-recovery to be refunded to this class. Company witness Ward testified that the Company accepted the $876,686 adjustment. The remaining $618,779 will be offset against the under-recovery that must be collected from the other four customer classes. Public Staff witness Peedin testified that DEP's EMF increment/(decrement) riders for each customer class should be approved based on the following over/(under)-recoveries:

	Test Period	
N.C. Retail Customer Class Customer Class	Over/(Under)- Recovery	Interest
Residential	$(21,282,684)	$ 0
Small General Service	(1,023,834)	0
Medium General Service	9,343,696	1,557,282
Large General Service	(17,750,323)	0
Lighting	(1,807,912)	0
Total	$(32,521,056)	$1,557,282

(may not add to sum due to rounding)

The Company proposed, and Public Staff witness Peedin did not oppose, deferring the under-recovery of $41,864,753 for one year without interest. As a result of these amounts, Public Staff witnesses Peedin and Metz recommended approval of the following EMF increment/(decrement) billing factors, excluding the regulatory fee:

N.C. Retail Customer Class	EMF Increment/ (Decrement) (cents/kWh)	EMF Interest Increment/ (Decrement) (cents/kWh)
Residential	0.000	0.000
Small General Service	0.000	0.000
Medium General Service	(0.084)	(0.014)
Large General Service	0.000	0.000
Lighting	0.000	0.000

The Commission concludes that the EMF increment/(decrement) billing factors set forth in the testimony and exhibit of Public Staff witness Peedin and the testimony of Public Staff witness Metz are reasonable and appropriate for use in this proceeding.

Company witness Ward calculated the Company's proposed fuel and fuel-related cost factors using a uniform bill adjustment method. She stated that the increase in fuel costs from the amounts approved in Docket No. E-2, Sub 1107 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 testimony of Public Staff witness Peedin.

Based upon the testimony and exhibits in the record, the Commission concludes that DEP's projected fuel and fuel-related cost of $853,205,811 for the North Carolina retail jurisdiction for use in this proceeding is reasonable. The Commission also concludes that the EMF increment/(decrement) riders and the EMF interest decrement rider for each class set forth in the testimony and exhibit of Public Staff witness Peedin and the testimony of Public Staff witness Metz 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 increase in fuel and fuel-related costs from the amounts approved in Docket No. E-2, Sub 1107 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 and related EMF interest, 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 2.179¢/kWh for the Residential class, 2.121¢/kWh for the Small General Service class, 2.258¢/kWh for the Medium General Service class, 2.417¢/kWh for the Large General Service class, and 1.657¢/kWh for the Lighting class, excluding regulatory fee, consisting of the prospective fuel and fuel-related cost factors of 2.179¢/kWh, 2.121¢/kWh, 2.356¢/kWh, 2.417¢/kWh, and 1.657¢/kWh, EMF increments/(decrements) of 0.000¢, 0.000¢, (0.0841)¢, 0.000¢, and 0.000¢/kWh, and EMF interest decrements of 0.000¢/kWh, 0.000¢/kWh, (0.014)¢/kWh, 0.000¢/kWh and 0.000¢/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, 2017, DEP shall adjust the restated base fuel and fuel-related cost factors in its North Carolina retail rates, as approved in Docket No. E-2, Sub 1045, amounting to 3.013¢/kWh for the Residential class, 3.001¢/kWh for the Small General Service class, 2.921¢/kWh for the Medium General Service class, 2.958¢/kWh for the Large General Service class, and 3.655¢/kWh for the Lighting class (all excluding the regulatory fee), by amounts equal to (0.834)¢/kWh, (0.880)¢/kWh, (0.565)¢/kWh, (0.541)¢/kWh and (1.998)¢/kWh, respectively, and further, that DEP shall adjust the resulting approved prospective fuel and fuel-related cost factors by EMF increments/(decrements) of 0.000¢/kWh for the Residential class, 0.000¢/kWh for the Small General Service class, (0.084)¢/kWh for the Medium General Service class, 0.000¢/kWh for the Large General Service class, and 0.000¢/kWh for the Lighting class (excluding the regulatory fee) and EMF interest decrements of 0.000¢/kWh for the Residential class, 0.000¢/kWh for the Small General Service class, (0.014)¢/kWh for the Medium General Service class, and 0.000¢/kWh for the Large General Service class (excluding the regulatory fee). The EMF increments/(decrements) and EMF interest decrements are to remain in effect for service rendered through November 30, 2018;

2. That DEP shall file appropriate rate schedules and riders with the Commission consistent with the rate adjustments ordered by the Commission in Docket No. E-2, Subs 1143, 1144, and 1146 as soon as practicable; and

3. That DEP shall work with the Public Staff to jointly prepare a proposed notice to customers of the rate adjustments ordered by the Commission in Docket No. E-2, Subs 1143, 1144, and 1146 and the Company shall file the proposed notice to customers for approval as soon as practicable.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of November, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

ELECTRIC – ADJUSTMENTS OF RATES/CHARGES

Appendix A

EXCLUDING REGULATORY FEE

	A	B	C	D	E	F
Class	Base Fuel Rate	Decrement to Base Fuel Rate	Prospective Rate (Columns A + B)	EMF Increment/ (Decrement)	EMF Interest (Decrement)	Billed Rate(Cols. C + D + E)
Residential	3.013	(0.834)	2.179	-	-	2.179
Small General Service	3.001	(0.880)	2.121	-	-	2.121
Medium General Service	2.921	(0.565)	2.356	(0.084)	(0.014)	2.258
Large General Service	2.958	(0.541)	2.417	-	-	2.417
Lighting	3.655	(1.998)	1.657	-	-	1.657

INCLUDING REGULATORY FEE

	A	B	C	D	E	F
Class	Base Fuel Rate	Decrement to Base Fuel Rate	Prospective Rate (Columns A + B)	EMF Increment/ (Decrement)	EMF Interest (Decrement)	Billed Rate(Cols. C + D + E)
Residential	3.017	(0.835)	2.182	-	-	2.182
Small General Service	3.005	(0.881)	2.124	-	-	2.124
Medium General Service	2.925	(0.566)	2.359	(0.084)	(0.014)	2.261
Large General Service	2.962	(0.542)	2.420	-	-	2.420
Lighting	3.660	(2.001)	1.659	-	-	1.659

DOCKET NO. E-22, SUB 543

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Dominion Energy North Carolina for Approval of Non-Residential Prescriptive Program	)))	ORDER APPROVING PROGRAM

BY THE COMMISSION: On July 28, 2017, Dominion Energy North Carolina (DENC or the Company), filed an application seeking approval of its Non-Residential Prescriptive Program (Program) as a new energy efficiency (EE) program pursuant to G.S. 62-133.9 and Commission Rule R8-68.

DENC states that the Program is designed to help reduce the participant's energy usage and peak demand through a variety of commercial grade EE measures. The average value of the incentive each eligible participant will receive is $10,091.

DENC's application includes estimates of the Program's impacts, costs, and benefits used to calculate the cost-effectiveness of the Program. DENC's calculations indicate that the Program will be cost-effective under the Total Resource Cost, the Utility Cost, and the Participant tests.

On August 24, 2017, the Commission granted the Public Staff and other interested parties an extension of time to September 27, 2017, in which to file comments.

On September 26, 2017, the Public Staff filed comments on the Program. No other party filed comments.

The Public Staff stated in its comments that the filing contains the information required by Commission Rule R8-68(c) and is consistent with G.S. 62-133.9, Commission Rule R8-68(c), and the Cost Recovery and Incentive Mechanism for Demand-Side Management and Energy Efficiency Programs (Mechanism), approved by Order dated May 22, 2017, in Docket No. E-22, Sub 464. The Public Staff also stated that DENC's estimates of program costs, net lost revenue, and performance incentive appeared to be consistent with the requirements of the Mechanism.

The Public Staff presented this matter at the Commission's Regular Staff Conference on October 16, 2017. The Public Staff stated that the Program has the potential to encourage demand-side management (DSM) and EE, appears to be cost effective, will be included in future DENC integrated resource plans (IRPs), and is in the public interest. The Public Staff recommended that the Commission approve the Program as a new EE program pursuant to Commission Rule R8-68, and determine the appropriate recovery of program costs, net lost revenues, and performance incentives associated with the Program in the Company's annual DSM/EE rider proceeding consistent with G.S. 62-133.9, Commission Rule R8-69, and the current DSM/EE cost recovery Mechanism.

Based on the foregoing and the entire record in this proceeding, the Commission finds good cause to approve the Program as a new EE program. The Commission further finds and concludes that the appropriate ratemaking treatment for the Program, including program costs, net lost revenues, and performance incentives, should be determined in DENC's annual cost recovery rider approved pursuant to Commission Rule R8-69.

IT IS, THEREFORE, ORDERED as follows:

1. That the Program is hereby approved as a new Energy Efficiency program pursuant to Commission Rule R8-68.

2. That the Commission shall determine the appropriate ratemaking treatment for the Program, including program costs, net lost revenues, and performance incentives, in DENC's annual cost recovery rider, in accordance with G.S. 62-133.9 and Commission Rule R8-69.

3. That DENC shall file with the Commission, within 10 days following the date of this Order, a revised tariff showing the effective date of the tariff.

ISSUED BY ORDER OF THE COMMISSION.
This the 16th day of October, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. E-7, SUB 1134

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 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	)	ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY WITH CONDITIONS

HEARD: Hearing Room 2115, Dobbs Building, Raleigh, North Carolina on August 30 and August 31, 2017; James W. Warren Citizens Center, Lincoln County Commissioners Hearing Room, Room 301, 115 W. Main Street, Lincolnton, North Carolina on August 16, 2017.

BEFORE: Chairman, Edward S. Finley, Jr., Presiding; Commissioners ToNola D. Brown-Bland, Bryan E. Beatty, Jerry C. Dockham, Lyons Gray, James G. Patterson and Daniel G. Clodfelter

APPEARANCES:

For the Applicant, Duke Energy Carolinas, LLC:

Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation, P.O. Box 1551/NCRH20, Raleigh, North Carolina 27602

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 225 Hillsborough Street, Suite 160, Raleigh, North Carolina 27603

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 Waste Awareness and Reduction Network, Inc. (NCWARN):

John D. Runkle, 2121 Damascus Church Road, Chapel Hill, North Carolina 27516

For the North Carolina Sustainable Energy Association (NCSEA):

Peter H. Ledford, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

ELECTRIC – ELECTRIC GENERATION CERTIFICATE

For the North Carolina Attorney General's Office:

Margaret A. Force, Assistant Attorney General, N.C. Department of Justice, Post Office Box 629, Raleigh, NC 27602

For the Sierra Club and the Natural Resources Defense Council (NRDC):

Gudrun Thompson and Nadia Luhr, Southern Environmental Law Center, 601 W. Rosemary Street, Suite 220, Chapel Hill, NC 27516

Bridget M. Lee, *pro hac vice*, Sierra Club, 50 F. Street, NW, Floor 8, Washington, D.C. 20001

For the Using and Consuming Public:

Dianna W. Downey, Staff Attorney, and Robert Josey, Staff Attorney, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On January 31, 2017, Duke Energy Carolinas, LLC ("Duke Energy Carolinas," "DEC" or the "Company") filed preliminary information, pursuant to Commission Rule R8-61(a), in advance of filing an application for a Certificate of Public Convenience and Necessity ("CPCN"). On June 12, 2017, pursuant to N.C.G.S. 62-110.1 and Commission Rule R8-61(b), the Company filed a verified CPCN application to construct a new, nominal 402 MW (winter rating) simple-cycle advanced combustion turbine natural gas-fueled electric generating unit, with fuel oil backup, and related transmission and natural gas pipeline interconnection facilities, to be located at its existing Lincoln County Combustion Turbine generating facility in Lincoln County, near Stanley, North Carolina (hereinafter the "Lincoln County CT Project" or "Project"). As part of the CPCN application, the Company included the supporting pre-filed direct testimony and exhibits of Matthew L. Kalemba, Lead Planning Analyst in Integrated Resource Planning and Analytics – Carolinas for Duke Energy Carolinas and Mark E. Landseidel, General Manager of Project Development for Duke Energy Corporation.

On June 28, 2017, the Commission issued an *Order Scheduling Hearings, Requiring Filing of Testimony, Establishing Procedural Guidelines and Requiring Public Notice.* The intervention of the Public Staff has been recognized pursuant to N.C. Gen. Stat. §62-15(d) and Commission Rule R1-19(e).

Motions to intervene were filed and granted for the following persons and organizations: North Carolina Waste Awareness and Reduction Network (NC WARN), Carolina Utility Customers Association, Inc. (CUCA), North Carolina Electric Membership Corporation (NCEMC), the North Carolina Sustainable Energy Association (NCSEA), the North Carolina Attorney General's Office, the Sierra Club, and the Natural Resources Defense Council (NRDC).

On August 7, 2017, the State Clearinghouse filed with the Commission comments submitted by Clearinghouse agencies regarding DEC's proposed generating facility. The cover letter stated: "Because of the nature of the comments, it has been determined that no further State Clearinghouse review action on your part is needed for compliance with the North Carolina Environmental Policy Act."

On August 14, 2017, the Public Staff filed a motion for an extension of time to file witness testimony, which the Commission granted on the same date.

On August 15, 2017, the Public Staff filed the testimony of Dustin R. Metz, Electric Engineer in the Electric Division of the Public Staff and John R. Hinton, Director of Economic Research Division of the Public Staff. On August 15, 2017, the Sierra Club and NRDC jointly filed the testimony of Thomas Vitolo, Ph.D., an economics consultant from Synapse Energy Economics.

As scheduled, a public hearing was held in Lincolnton on August 16, 2017. The following public witnesses testified at the public hearing: Rita Burns-Wooten, Joe Wooten, Granville Angell, Alice Angell, Kevin Poet, and Luis Rodriguez.

On August 25, 2017, Duke Energy Carolinas filed the rebuttal testimony of Phillip O. Stillman, Director of Load Forecast and Fundamentals, as well as that of witnesses Kalemba and Landseidel. No other party filed testimony in this matter.

The matter came on for hearing as scheduled on August 30, 2017, and the pre-filed testimony was received subject to cross-examination. On September 1, 2017, pursuant to the Commission's request during the evidentiary hearing, Duke Energy Carolinas filed DEC Confidential Late-Filed Exhibit No. 1, the Engineering, Procurement and Construction Agreement with Siemens Energy Inc. ("Siemens"), and DEC Confidential Late-Filed Exhibit No. 2, the Long-Term Service Agreement with Siemens.

On September 8, 2017, the Commission issued a notice of mailing of transcript and ordered the parties to submit briefs and/or proposed orders no later than September 30, 2017. On September 28, 2017, the Attorney General requested an extension of time to file proposed orders and briefs. On September 28, 2017, the Commission granted the motion, extending the due date until October 9, 2017.

On October 9, 2017, the Public Staff and the Company each filed a Proposed Order. On that same date, Sierra Club/NRDC, the AGO, NCSEA and NC WARN filed briefs, and CUCA filed a letter supporting the imposition of the conditions proposed by the Public Staff.

Based upon consideration of the pleadings, testimony, and exhibits received into evidence, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Duke Energy Carolinas, LLC 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. Pursuant to G.S. 62-110.1 and Commission Rule R8-61(b), a public utility or other person must receive a CPCN from the Commission prior to constructing an electric generating facility to be directly or indirectly used for public utility service.

3. Duke Energy Carolinas plans to construct a new nominal 402 MW simple-cycle CT dual-fuel (natural gas and ultra-low sulfur diesel fuel) electric generating unit and related transmission and natural gas pipeline interconnection facilities at its existing Lincoln Combustion Turbine generating facility in Lincoln County, North Carolina. The Lincoln CT Project will use a Siemens advanced-class series CT unit; the plant is scheduled to begin producing electricity in 2020 during an extended commissioning, testing and validation period; and Duke Energy Carolinas will take care, custody and control of the unit and begin commercial operation in 2024.

4. Duke Energy Carolinas' 2016 Integrated Resource Plan ("IRP"), filed with the Commission on September 1, 2016 in Docket No. E-100, Sub 147, shows load growth, existing unit retirements, and the need for capacity additions to meet Duke Energy Carolinas customers' needs over the next fifteen years. The 2016 IRP identifies the need for an additional 1,689 MW of new resources to meet customers' energy needs by 2025 and 3,923 MW by 2031. As currently projected, there is a need for the Lincoln CT Project in the 2024/25 timeframe. The Lincoln CT Project is therefore consistent with the Company's 2016 IRP.

5. Any potential risks with approval of the CPCN at this stage are outweighed by the benefits to customers from the project.

6. The Lincoln CT Project will provide a cost-effective peaking generation resource for Duke Energy Carolinas' system and customers. The technology selected by the Company for the Lincoln CT Project will provide enhanced reliability, low turn down, fast ramp, and efficient dispatch capability for the Duke Energy Carolinas system. The load following capability of the Lincoln CT Project will provide additional system flexibility and generation ancillary service benefits to help accommodate the impacts resulting from the increasing amounts of intermittent renewable resources being added to the Duke Energy Carolinas system. The advanced-class simple cycle CT technology proposed by Duke Energy Carolinas for the Lincoln CT Project is a practical technological option to provide peaking generation capacity by 2024, when it is needed.

7. Duke Energy Carolinas considered a broad spectrum of demand-side management options ("DSM"), energy efficiency ("EE") programs, and renewable resources in its IRP process and in making the decision to pursue the Lincoln CT Project as the best option to meet its customers' resource needs. Duke Energy Carolinas cannot rely upon EE, DSM and renewables to eliminate or delay its needs for generation system peaking capacity in the 2024 timeframe.

8. Duke Energy Carolinas properly evaluated the wholesale market in determining how to meet the capacity needs that will be met by the Lincoln CT Project.

9. Duke Energy Carolinas conducted a comprehensive siting process and appropriately selected its existing Lincoln County CT generation complex as the site for the Lincoln CT Project.

10. The Lincoln CT Project will utilize all required environmental controls, and the necessary environmental permitting is subject to the jurisdiction of other State agencies.

11. The Company's estimated construction cost for the Lincoln CT Project is reasonable and is hereby approved. Duke Energy Carolinas shall submit a progress report each year during construction that includes any revisions in the cost estimates as required by N.C.G.S. 62-110.1(f).

12. Pursuant to N.C.G.S. 62-110.1, the issuance of a Certificate of Public Convenience and Necessity for the Lincoln CT Project proposed by Duke Energy Carolinas is required by the public convenience and necessity, subject to the conditions set forth in the ordering paragraphs below.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

These findings are informational, procedural, and jurisdictional in nature and are uncontroverted.

North Carolina General Statute 62-110.1 is intended to provide for the orderly expansion of electric generating capacity in order to create a reliable and economical power supply and to avoid the costly overbuilding of generation resources. State ex rel. Utilities Comm. v. Empire Power Co., 112 N.C. App. 265, 278 (1993), disc. rev. denied, 335 N.C. 564 (1994); State ex rel. Utilities Comm. v. High Rock Lake Ass'n, 37 N.C. App. 138, 141, disc. rev. denied, 295 N.C. 646 (1978). A public need for a proposed generating facility must be established before a certificate is issued. Empire, 112 N.C. App. at 279-80; High Rock Lake, 37 N.C. App. at 140. Beyond need, the Commission must also determine if the public convenience and necessity are best served by the generation option being proposed. The standard of public convenience and necessity is relative or elastic, rather than abstract or absolute, and the facts of each case must be considered. State ex rel. Utilities Comm. v. Casey, 245 N.C. 297, 302 (1957). "[Chapter 780 of the 1975 Session Laws], codified as G.S. 62-110.1(c)-(f), directs the Utilities Commission to consider the present and future needs for power in the area, the extent, size, mix and location of the utility's plants, arrangements for pooling or purchasing power, and the construction costs of the project before granting a certificate of public convenience and necessity for a new facility." High Rock Lake, 37 N.C. App. at 140-41.

As hereinafter discussed in this order, the Commission has considered all of these factors -- need, the size and mix of existing plants, pooling, purchases, DSM, alternative technologies including renewables, fuel costs, and construction costs -- in determining whether the public convenience and necessity are served by Duke Energy Carolinas' proposal in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence in support of this finding is based upon the verified application and the testimony and exhibits of Duke Energy Carolinas witnesses Mark Landseidel and Matthew Kalemba, and the testimony of Public Staff witness Dustin Metz.

ELECTRIC – ELECTRIC GENERATION CERTIFICATE

Mark E. Landseidel, Duke Energy's General Manager of Project Development in the Project Management and Construction Department, testified to the project details of the planned Lincoln CT Project. The Lincoln County CT Project will consist of a new nominal 402 MW (winter rating) simple-cycle advanced combustion turbine natural gas-fueled electric generating unit, with fuel oil backup, and related transmission and natural gas pipeline interconnection facilities. This project will provide peaking generating capacity to the Duke Energy Carolinas system. The plant will be the first Siemens advanced-class series test and validation CT unit. The plant is scheduled to begin generating electricity for the benefit of DEC customers in the third quarter of 2020 during an extended commissioning and testing period, and DEC will take care, custody and control of the unit and begin commercial operation in the fourth quarter of 2024. The Company has sixteen existing CTs at the Lincoln CT site totaling 1,488 MW (winter rating), which provide peaking generation to the Company's customers. The Lincoln County CT Project will be sited adjacent to the existing CT units.

In 2016, Siemens approached Duke Energy Carolinas as part of its efforts to seek a utility customer host site for testing and validation of the new advanced-class gas turbine it is developing. The advanced-class Siemens CT will be designed to compete with other advanced-class series CTs being introduced into the market by GE and Mitsubishi. The Company conducted a due diligence evaluation of the new Siemens design development, including visits to Siemens' turbine manufacturing and test facilities in Germany and Charlotte. Siemens' new advanced-class turbines will be manufactured at its Charlotte facility. These advanced-class turbines will provide higher output, improved efficiency and faster ramp rates than existing large frame gas turbines.

The Lincoln County CT Project will be designed with a single 230 kV Generator Step-Up transformer, 230 kV bus line, and interconnected to the existing 230 kV Lincoln County CT electrical switchyard. No new transmission lines are planned to be constructed outside the Lincoln County CT property, and additional interconnection study work is underway to determine if any offsite transmission system upgrades are required.

The Project will be dual fuel, capable of burning pipeline natural gas or back-up ultra-low sulfur diesel fuel from on-site storage facilities. The existing Piedmont Natural Gas Company, Inc. ("Piedmont") pipeline from Transco will be modified to provide service to the Project at a location adjacent to the Project. Duke Energy Carolinas will have an interruptible transportation service agreement with Piedmont to provide gas transportation service for the Project. The plant gas supply will be served initially from Transco utilizing Duke Energy Carolinas' existing gas transportation service agreements and supply portfolio. The fuel oil unloading and storage facilities built for the existing Lincoln County CTs will be expanded with an additional storage tank.

Construction would begin in mid-2018, and Siemens will bring the unit online in a series of three versions as part of the comprehensive testing and validation process. Version A will have a nominal winter rating of 369 MW and will begin testing and validation in 2020. Version B will have a nominal winter rating of 382 MW, and begin testing and validation in 2022. The final commercial operation version C will have a nominal winter rating of 402 MW and begin testing and validation in 2023, with Duke Energy Carolinas taking care, custody and control of the unit in late 2024. During the approximately four-year extended testing and validation period, Siemens will determine the timing and nature of operation of the unit; however, Duke Energy Carolinas will receive the capacity at no cost and the energy delivered to the Duke Energy Carolinas grid at only the variable cost of the fuel. Furthermore, Siemens will pay for any inefficient fuel use to the extent the unit is run out of economic merit order. Although Siemens will control the operation of the unit during the four-year extended commissioning, testing and validation period, DEC will still have the ability to direct Siemens to make changes in the unit's operation if system needs so require, including requiring Siemens to stop operating the unit or reduce output.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence in support of this finding is based upon the verified application and the testimony and exhibits of Duke Energy Carolinas witnesses Landseidel, Phillip Stillman, and Kalemba, including the 2016 DEC IRP and 2017 DEC IRP Update Report, the testimony of Public Staff witnesses Robert Hinton and Dustin Metz and NRDC/Sierra Club witness Dr. Thomas Vitolo, and NRDC/Sierra Club Confidential Cross Exhibit 1.

Matthew R. Kalemba, Duke Energy Carolinas' Lead Planning Analyst, offered extensive testimony as to the comprehensive planning process that led to the development of the Duke Energy Progress 2016 IRP and the decision to add the Lincoln CT Project. Mr. Kalemba also testified to the 2017 DEC IRP Update Report, portions of which were introduced as NRDC/Sierra Club Confidential Cross Exhibit 1, and which was filed subsequent to the hearing on September 1, 2017, in Docket No. E-100, Sub 147.

The Duke Energy Carolinas 2016 IRP identifies the need for an additional 1,689 MW (winter rating) of new resources to meet customers' energy needs by 2025 and 3,923 MW by 2031. The Duke Energy Carolinas 2016 IRP includes the need for 468 MW of CT capacity in the winter of 2024/2025, which will be met in part by the Lincoln County CT Addition.

Mr. Kalemba testified that the 2016 IRP incorporates a 15-year load forecast, purchase power contracts, existing generation, energy efficiency and demand-side management, new resource additions, and a minimum target planning reserve margin of 17.0%. The comprehensive planning process for the 2016 IRP demonstrates that a combination of renewable resources; energy efficiency and demand-side management programs; and additional baseload, intermediate, and peaking generation are required over the next 15 years to reliably meet customer demand. Mr. Kalemba explained that, after accounting for increased energy efficiency impacts, Duke Energy Carolinas' Spring 2016 forecast shows average annual growth in summer peak demand of 1.2 percent, winter peak demand growth of 1.3 percent, and the average territorial energy growth rate of 1.0 percent.

The 2016 IRP examined future resource plans under scenarios that did, and did not, include future carbon prices. Under the no carbon Base Case, which consisted of no CO_2 emission costs and no new nuclear generation, the portfolio consisting of 142 MW (2,202 MW nameplate) of compliance and non-compliance renewable generation, 1,221 MW of new natural gas combined cycle capacity, 2,808 MW of new natural gas CT capacity (including the Lincoln County CT Project), 85 MW of nuclear uprates capacity, 669 MW of demand-side management, and 461 MW of energy efficiency was selected over the planning horizon.

Mr. Kalemba testified that the minimum planning reserve margin of 17.0% was based on new resource adequacy studies that DEC and DEP commissioned and that were finalized in 2016. Three main drivers led to the commissioning of these studies including: 1) the high penetration of solar resources that have been connected to the Utilities' transmission and distribution systems in the past two to three years; 2) the high volume of solar resources currently in the Utilities' interconnection queues; and 3) the significant load response to cold weather that was experienced during the 2014 and 2015 winter periods.

Mr. Kalemba testified to the details of the load forecast contained in the 2016 IRP, but noted that in addition to customer growth, plant retirements and expiring purchased power contracts create the need to add incremental resources to allow the Company to meet future customer demand. In particular, over the last several years, aging, less efficient coal plants have been replaced with a combination of renewable energy, EE, DSM, and state-of-the-art natural gas generation facilities. Additionally, DEC plans to retire the 1,161 MW Allen Steam Station, with Units 1-3 scheduled to retire by December 2024 and Units 4 and 5 in 2028. The combination of load growth and these planned retirements contribute to the need for the Lincoln County CT Project.

The Commission has accepted Duke Energy Carolinas 2016 IRP as reasonable for planning purposes. On June 17, 2017, the Commission issued its Order Accepting Integrated Resource Plans And Accepting REPS Compliance Reports in Docket No. E-100, Sub 147, which held that Duke Energy Carolinas' (and the other IOUs) "forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy those loads, and reserve margins are reasonable for planning purposes, and the Commission accepts the IRP Reports as filed in this docket." Public Staff witness Hinton testified to the Public Staff's review of the Company's 2016 IRP and that it supports the need for new combustion turbine peaking generation in 2024.

Mr. Kalemba also testified to the Duke Energy Carolinas 2017 IRP Update, relevant excerpts from which were provided to intervenors in response to data requests (NRDC/Sierra Club Confidential Cross Ex. 1), and which was filed in Docket. No. E-100, Sub 147 on September 1, 2017, the day following the completion of the evidentiary hearing. Mr. Kalemba explained the significant new capacity needs that Duke Energy Carolinas has over the 15-year IRP planning horizon, 3,923 MW in the 2016 IRP. The 2017 IRP Update shows a resource need or gap in every year from 2024 through 2032. In comparison to the 2016 IRP, the 2017 IRP Update shows the first need in 2024, instead of 2022. As a result, the 1,221 MW combined cycle need, shown in 2022 in the 2016 IRP, has now shifted to a 1,282 MW combined cycle need in 2024, resulting in an even greater resource need in 2024 than was shown in the 2016 IRP. The 2017 IRP Update includes the 402 MW Lincoln CT as a designated resource in 2024, but still has a 337 MW resource gap in that year.

Mr. Kalemba also testified to the reduction in load forecast contained in the DEC 2017 IRP Update, when compared to the 2016 IRP load forecast, but explained that the lower load forecast did not move the first need beyond 2024. The 2017 IRP Update still shows a resource gap in 2024, which is primarily dictated by the retirement of the 604 MW Allen Coal Units 1-3 by December 2024 as required by the Company's New Source Review litigation settlement. Mr. Kalemba further testified that even if the Company's load forecast were to continue to decline, "it is almost certain that there will be a need for new generation in 2024, and the Lincoln CT represents a cost-effective means to meet that need."

The Public Staff and NRDC/Sierra Club witnesses questioned the timing of the need for the Lincoln CT Project and asserted many possible changes to the underlying assumptions of the IRP that could materialize between now and the Lincoln CT Project's 2024 commercial operation date when Duke Energy Carolinas will take care, custody and control of the unit. NRDC witness Dr. Vitolo criticized the accuracy of Duke Energy Carolinas' past load forecasts as overstated; however, the Commission has accepted the Company's past load forecasts and found them to be reasonable for planning purposes in the IRP proceedings, including the 2016 IRP. In rebuttal, Duke Energy Carolinas witness Phillip O. Stillman, Director of Load Forecast and Fundamentals, disagreed with Dr. Vitolo's tests to validate his claims, and noted that Dr. Vitolo's conclusions were misleading because he did not consider the many changes in DEC's wholesale load, he gave no consideration to the significant decline in textile industry in the DEC territory, he gave no consideration to the 2007-2009 recession when DEC experienced a nearly 20% decline in industrial sales, and Dr. Vitolo's calculations were performed off the summer peak projections with no consideration given to the winter peak, even though Dr. Vitolo agreed that this is a winter need. Mr. Stillman further explained that if Dr. Vitolo had performed the same tests based on a winter peak the results would have been different and that under the seven-year-ahead test the forecasted peaks would have been under projected nearly as often as they were over projected. While Mr. Stillman acknowledged that the Commission's 2016 IRP Order noted that DEC's load forecast "may be high," he testified that the concerns noted relate to the sensitivity of how customers react to winter peaks and that the Company is making refinements to the forecasting methodology in the 2017 IRP Update as requested by the Commission.

Based upon the 2016 IRP, the 2017 IRP Update and the entire record before the Commission, if the Commission were to deny the CPCN for the Lincoln CT Project, it is likely that DEC would need to seek a CPCN for a significantly higher cost CT to replace the Lincoln CT Project. Such a result would be short-sighted and contrary to the public convenience and necessity.

The Commission concludes that DEC has demonstrated a need for additional peak generating capacity in the 2024 time period. Because of the unique and beneficial arrangement with Siemens for DEC to host the extended commissioning, testing and validation period for this new advanced-class turbine from 2020 to 2024 when DEC will assume care, custody and control of the unit, the Commission concludes that this approach for the timing of the Lincoln CT Project is appropriate and consistent with the public convenience and necessity. For these reasons, the Commission concludes that the need for the Lincoln CT Project has been adequately demonstrated.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence in support of this finding is based upon the verified application and the testimony and exhibits of Duke Energy Carolinas witnesses Landseidel, Phillip Stillman, and Kalemba, including the 2016 DEC IRP and 2017 DEC IRP Update Report, the testimony of Public Staff witnesses Robert Hinton and Dustin Metz and NRDC/Sierra Club witness Dr. Thomas Vitolo, and NRDC/Sierra Club Confidential Cross Exhibit 1.

Public Staff witnesses Metz and Hinton and NRDC/Sierra Club witness Vitolo testified that because the IRP need date for the Lincoln CT Project is seven years from now in 2024, any number of changes to the load forecast, cost of technology, availability of alternative supply side options such as renewables and battery storage and other uncertainties were "possible." Dr. Vitolo asserted that it is premature for the Commission to issue a CPCN for the Lincoln CT Project, and Mr. Metz and Mr. Hinton asserted that it is premature for the Commission to issue a CPCN unless additional conditions are imposed. The Public Staff and NRDC/Sierra Club witnesses compared the timing between the filing of the CPCN application and the IRP need date for the Lincoln CT Project to that of the Duke Energy Progress ("DEP") contingent Asheville CT project in Docket No. E-2, Sub 1089, which was denied by the Commission without prejudice to DEP to refile. The Commission finds that the facts and circumstances of the Asheville CT are distinguishable from those here. First, DEP sought a CPCN for the Asheville CT project in 2016 with a potential commercial operation date in 2023; however, DEP did not propose to begin construction of the Asheville CT unit upon receipt of the CPCN because it was contingent upon efforts to work with customers in the DEP Western Region to utilize DSM, EE and other programs to attempt to delay or eliminate the peak demand growth that would require the contingent Asheville CT unit. Here, Duke Energy Carolinas needs a CPCN for the Lincoln CT Project to support the commencement of construction in 2018 to enable the operation of the unit in 2020. The Lincoln CT Project is scheduled to begin generating electricity in 2020 during an extended commissioning, testing and validation period, and DEC will take care, custody and control of the unit in 2024 which aligns with the IRP need. Furthermore, Company witness Kalemba testified that the Asheville CT need is much more sensitive to load forecast changes, efforts to adopt EE in the DEP Western Region, and transmission modifications than the timing of the Lincoln CT Project, which is why the Asheville CT CPCN was filed as contingent upon the efforts to delay or eliminate the peak load demand. Mr. Kalemba further explained that the need for the Lincoln CT Project is primarily driven by the 604 MW Allen coal unit retirements in 2024 and that "while the comparison and timing are similar, the risks around those projects [Asheville CT and Lincoln CT] are not comparable."

Second, although the Public Staff and NRDC/Sierra Club argued that DEC is seeking a CPCN seven years before the generation is needed, with a corresponding seven-year period when the underlying assumptions supporting the CPCN application could change, Company witness Landseidel testified that those parties had underestimated the timing necessary to design, permit and construct an advanced-class turbine. Mr. Landseidel explained that if the Company were to need an advanced-class CT in 2024, without the extended commissioning, testing and validation period, the Company would begin design in 2020 and file the preliminary CPCN information with the Commission in early 2021. Upon questioning by the Commission, Mr. Landseidel confirmed that, as such, there is only an approximately two to two and a half year window after receipt of a CPCN order in this case when the possible uncertainties noted by the Public Staff and NRDC/Sierra Club could potentially develop. Even then, because of the significant capacity needs by 2024, the Company may need to file a CPCN application for a combined cycle project sooner. From an IRP perspective, although Mr. Kalemba acknowledged that "anything is possible," a two to two and half year window is "not a great deal of time" for the concerns of the Public Staff and NRDC/Sierra Club to materialize. The Commission agrees.

Mr. Kalemba further addressed the Public Staff and NRDC/Sierra Club's concerns as to timing and need by explaining that although there is some risk that the underlying IRP need and analysis that supports any proposed new generation resource CPCN application could change during the course of project construction and before the ultimate commercial operation of that resource, this type of risk is always present. Mr. Kalemba also discussed N.C.G.S. 62-110.1(e1), which allows the Commission to review a CPCN to determine "whether changes in the probable future growth of the use of electricity" require modification or even revocation of a CPCN if the Commission finds that completion of the generation facility is no longer in the public interest. The Commission agrees and finds that the CPCN statute already contemplates that the underlying need for any generation facility which receives a CPCN could change prior to completion, and provides the Commission with a statutory avenue to address such a change in the unlikely event that it occurs during the construction or commission, testing and validation period for the Lincoln CT Project.

Furthermore, the Commission concludes that the risks of possible changes to the timing and need for the Lincoln CT Project are outweighed by the overwhelming and known benefits to customers from the project. As is discussed in greater detail, infra, first, DEC negotiated a significant multi-million dollar discount for the capital cost of the CT from Siemens, which Public Staff witnesses Metz and Hinton have acknowledged. Next by not taking care, custody, and control of the unit until 2024, DEC's customers will receive four years of free energy and capacity during Siemens' testing and validation period prior to DEC seeking to recover its costs for the Lincoln CT Project, along with fuel savings. Additionally, Siemens has agreed to reimburse the Company and its customers for inefficient fuel costs during that testing and validation period. DEC negotiated a discounted Long-Term Service Agreement ("LTSA") with Siemens, which provides for predictable maintenance costs and risk in line with a current generation machine. Also, simply having the CT operating on DEC's system will allow the Company to become familiar with the technology and will allow the Company to raise any concerns with the unit's operation and its impact on the system prior to assuming care, custody and control. Furthermore, the opportunity for DEC to partner with Siemens to test and validate this new turbine, and its many significant benefits, would be lost if the Commission were to adopt the position of NRDC/Sierra Club or adopt all of the proposed conditions of the Public Staff, all to the detriment of DEC's customers.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 6

The evidence in support of this finding is based upon the verified application and the testimony and exhibits of Duke Energy Carolinas witnesses Kalemba and Landseidel, including the Company's late-filed exhibits, the testimony of Public Staff witnesses Hinton and Metz and NRDC/Sierra Club witness Vitolo.

Witness Kalemba testified to the economic analysis that DEC performed and which revealed that the Lincoln CT Project is the least cost option for customers in the 2024 time period. Mr. Kalemba discussed several quantitative reasons why DEC concluded that the Lincoln CT Project is the best resource addition for customers. First, the Lincoln County CT Project is being offered to the Company at a significant discount to similar advanced technology CTs available in the marketplace - - approximately **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**

% total project cost savings. Additionally, in comparison to the less advanced, less efficient F-class CTs, the Utility is receiving an approximate **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** % total project cost savings. Second, the Company will not seek to recover the capital costs of the CT in rates until after assuming care, custody and control in 2024; however, the Company's customers will benefit from the energy generated by the CT during its extended commissioning period that begins in 2020. During the approximately four-year extended testing and validation period, Siemens will determine the timing and nature of operation of the unit; however, DEC will receive the energy delivered to the Company's grid at only the variable cost of the fuel. As such, DEC customers will receive free capacity and essentially free energy during the four-year testing and validation period. Furthermore, Siemens will pay for any inefficient fuel use to the extent the unit is run out of economic merit order during this period. Third, the Lincoln County CT is approximately 6% more fuel efficient than current F-Class options, and is comparable to other suppliers' advanced-class gas turbines. As such, the new unit would be DEC's most efficient peaking unit and will be available for economic dispatch with an estimated capacity factor of 16%. However, the Lincoln CT Project could have capacity factors as high as 50% depending upon fuel prices and could therefore dispatch as an intermediate resource. Finally, major maintenance costs associated with the Lincoln County CT Project are deferred until the Company takes care, custody, and control of the unit in late 2024. The long-term major maintenance costs that become DEC's responsibility in 2024 are covered by the LTSA whose terms are being provided at a significant discount to those associated with the less advanced F-Class CT technologies.

Mr. Kalemba explained that the Present Value Revenue Requirement ("PVRR") analysis for the Lincoln CT Project is conducted using the 2016 IRP without the CO_2 legislation expansion plan as the Base Case. This Base Case is compared to a case where the 468 MW Undesignated F-Class CT need identified in the 2024/2025 timeframe is mostly replaced by the 402 MW Lincoln CT Project. The balance of the MWs that are not replaced by the Lincoln CT Project are replaced by an F-Class CT in that same time period. Through this analysis, it was determined that the Base Case PVRR savings associated with the Lincoln CT project is **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**. These PVRR savings are centered around three main variables:

1. Lower Capital Cost: The Siemens Advanced Turbine is being offered at an approximate **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** cost savings versus the avoided F-Class CT. Additionally, from a timing standpoint, the Lincoln CT aligns with the designated need identified in the IRP as DEC is taking care, custody, and control in October 2024. From a PVRR standpoint, the net capital expenditures savings of this project versus the Base Case is approximately **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**.
2. Improved System Fuel Cost: The Siemens Advanced Turbine is more efficient than F-Class CTs that were included in the Company's 2016 IRP, and this improved efficiency leads to reduced fuel and operating costs. Additionally, while DEC will not be taking care, custody, and control of the unit until 2024, DEC's customers will benefit from the energy produced from the unit beginning in the third quarter of 2020 as the Advanced Turbine begins its extended commissioning and testing period. From a PVRR standpoint, the system fuel and operating costs are reduced by approximately **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** versus the Base Case.
3. Lower Maintenance Costs: The negotiated LTSA for the Advanced CT is approximately **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** lower on a $/MW-Start basis

> compared to the generic F-Frame CT assumptions. From a PVRR standpoint, the long-term maintenance costs savings are approximately **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** versus the Base Case.

In addition to the Base Case analysis, several sensitivities were conducted around fuel price, as well as a sensitivity that includes an expansion plan with Lee Nuclear and a carbon tax on carbon emissions. These sensitivities all showed positive benefits from the Lincoln CT project.

NRDC/Sierra Club witness Vitolo asserted that DEC had not shown that the Lincoln CT Project is the least cost resource option, and based his opinion on the possibility that potential changes to the cost or viability of other alternatives could develop before 2022, when he asserted that DEC would need to make a decision on a resource to meet a 2025 capacity need. Public Staff witness Hinton reviewed DEC's PVRR analysis and found it to be reasonable and determined that the "economic justification is correct." Mr. Hinton also agreed that the PVRR of the Lincoln CT Project is very favorable to customers. Mr. Hinton also concluded that, as proposed, the Lincoln CT Project "will be a cost-effective resource." Mr. Hinton voiced concerns about the risks of possible changes in the underlying assumptions related to issues such as changes to load forecast, development of alternative technologies, battery storage, DSM/EE, and renewables that caused the Public Staff to support a CPCN only if additional conditions were adopted by the Commission. DEC witness Kalemba testified, however, that even if the need was delayed for an additional six years until the winter of 2030/2031, the Lincoln CT Project would still have a positive PVRR and be beneficial to customers. The Commission is not persuaded by the Public Staff and NRDC/Sierra Club's concerns and finds that the economic justification for the Lincoln CT Project is significant and that the public convenience and necessity supports the construction of the Lincoln CT Project as proposed. The possible risks raised by the Public Staff and NRDC/Sierra Club are just that, possible but not absolute, and the Commission finds that they are outweighed by the significant, measurable and demonstrable benefits to customers from the Lincoln CT Project. DEC has the opportunity now to take advantage of very advantageous terms it has negotiated with Siemens and such benefits would be lost to the detriment of customers if the Commission were to deny the CPCN as requested by the Public Staff and NRDC/Sierra Club, and such a result would thereby require DEC to seek another CPCN in a couple of years at what is very likely to be a much higher customer cost.

NRDC/Sierra Club witness Vitolo expressed technology concerns about the "yet-untested design" of the new Siemens advanced-class turbine. Public Staff Hinton testified, however, that aside from the risk items that gave the Public Staff pause to support the CPCN only if additional conditions were imposed, "we are supportive of the economics and the engineering associated with this unit. We are - - we're solid behind that." Company witness Landseidel testified to the extensive due diligence Duke Energy Carolinas undertook to evaluate the new Siemens advanced-class turbine design, including visits to Siemens facilities in Germany and Charlotte, and that the Company was satisfied that the technology did not present an unacceptable risk. Mr. Landseidel described the evolution of the CT technology over the last 25 years and how the new Siemens advanced-class unit will build upon the efficiency gains over the years and will be comparable to the GE and Mitsubishi advanced-class turbines. Mr. Landseidel testified that he personally visited these other manufacturers' new advanced-class turbine projects under construction in Oklahoma and Texas as part of the Company's due diligence. Mr. Landseidel also explained that Siemens is an established and proven gas turbine supplier and has all incentives to match or better any improvement from other advanced-class turbine manufacturers.

Mr. Landseidel also testified to the many protections the Company negotiated with Siemens to address technology risk. In his rebuttal testimony to NRDC/Sierra Club witness Vitolo's concerns about the Siemens technology, Mr. Landseidel explained that the EPC agreement provides a significant price discount (as validated by Burns & McDonnell and verified by the Public Staff), significant benefits to customers during testing and validation, high unit performance with guarantees, schedule guarantees, a favorable Long-Term Service Agreement, and perhaps the ultimate technology risk mitigation - - per the EPC agreement with Siemens, if in the unlikely event that the advanced CT does not meet certain DEC performance criteria, Siemens must then replace the advanced CT with two of the existing technology F-frame units at no additional cost. In addition, Siemens would be responsible for **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** Company witness Kalemba testified that if Siemens has to replace the advanced-class turbine with two F-frame CT units per the EPC agreement, such CTs would be for a total of 468 MW at the same cost of the 402 MW advanced-class CT, therefore resulting in an even lower $/kW benefit for customers. The EPC agreement also contains additional technology risk mitigation provisions that require Siemens to pay liquidated damages if the final version of the advanced-class turbine is either Version A or Version B at commercial operation, instead of the planned Version C. Furthermore, the EPC contains **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** Mr. Landseidel testified that in his 35 years working for Duke Energy in major project construction and management, he has never been involved in a more favorable EPC contract than the one negotiated with Siemens for the Lincoln CT Project.

Mr. Landseidel also testified to the analysis performed by Burns & McDonnell to prepare a cost estimate for a GE advanced-class turbine at the Lincoln CT site. The cost estimate for the Lincoln CT unit is **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** less than the Burns & McDonnell cost estimate, or less than **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** of the market price for a similar unit. Mr. Landseidel described this as **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**

During the extended testing and validation period, Siemens will also maintain a spare parts inventory, take parts life risk including in/out costs, and be responsible for all major maintenance costs until the unit goes into commercial operation. Siemens will also provide a full two-year warranty on the entire facility after DEC puts the unit into commercial operation. Siemens has also agreed to favorable long-term parts and maintenance agreement terms, which provide additional cost and risk benefits to DEC and DEC's customers. Mr. Landseidel testified to the **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**

The technology selected for the Lincoln County CT Project will provide enhanced reliability, low turn down, fast ramp and efficient dispatch for the Duke Energy Carolinas system. Duke Energy Carolinas currently has approximately 735 MW (nameplate) of compliance and non-compliance intermittent renewable generation interconnected to its system, and the DEC 2016 IRP projects that a total of approximately 2,168 MW (nameplate) of rated compliance and non-compliance renewable energy resources will be interconnected to the Company's system by 2031. These resources help the Company comply with renewable energy mandates and provide important energy benefits to DEC's customers; however, the inherent intermittency of these resources does not allow the capacity to be dispatched or contribute to reliability in the same manner as a traditional resource such as a combustion turbine. Thus, the load following capability of the Lincoln County CT Project provides additional system flexibility, and reliability, to help accommodate the impacts resulting from the increasing amounts of intermittent resources being added to the Duke Energy Carolinas system.

The selection of the Siemens technology also helps to support economic development in North Carolina as both the plant and the manufacturing facility for the major components of the CT are located in North Carolina. With approximately 1,700 people employed by Siemens in the Greater Charlotte area and an additional 150-plus temporary jobs required for the construction, testing, and commissioning of the facility, the Lincoln County CT Project will help support economic growth in the Charlotte region. Finally, by providing Siemens with the opportunity to test and develop their advanced technology on the grid, DEC is helping to promote competition in the CT manufacturing marketplace which can have long-term benefits for DEC's customers. In addition, Mr. Kevin Poet, Operations Manager for the Siemens Charlotte Energy Hub, testified at the Lincolnton public hearing to the regional economic development and local job creation that the Lincoln CT Project and future advanced-class turbine orders will create.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 7

The evidence in support of this finding is based upon the verified application and the testimony and exhibits of Duke Energy Carolinas witness Kalemba, including the 2016 DEC IRP and 2017 DEC IRP Update, the testimony of Public Staff witness Hinton and NRDC/Sierra Club witness Vitolo.

Company witness Kalemba testified to the Company's consideration of DSM, EE and renewables in its 2016 IRP and in its decision to seek approval for the Lincoln CT Project. The comprehensive planning process for the 2016 IRP demonstrates that a combination of renewable resources; EE and DSM programs; and additional baseload, intermediate, and peaking generation are required over the next fifteen years to reliably meet customer demand. Under the no carbon Base Case, which consisted of no CO_2 emission costs and no new nuclear generation, the portfolio consisting of 142 MW (2,202 MW nameplate) of compliance and non-compliance renewable generation, 1,221 MW of new natural gas combined cycle capacity, 2,808 MW of new natural gas CT capacity (including the Lincoln County CT Project), 85 MW of nuclear uprates capacity, 669 MW of demand-side management, and 461 MW of energy efficiency was selected over the planning horizon.

Mr. Kalemba testified in detail as to how DSM and EE programs and renewable resources were analyzed in the Company's IRP. With respect to solar, EE and DSM, only DSM (demand response) programs are truly dispatchable. The Company has already included its estimate of cost-effective DSM/EE and has identified the 2024 need as an incremental need in addition to its investment in EE and DSM. Further, the proposed Lincoln County CT Project will satisfy a critical resource need that provides not only peaking capacity, but also provides generation ancillary service benefits that are becoming increasingly important as more non-dispatchable and intermittent renewable generation is added to the DEC system. As a result, the Lincoln County

CT Project helps to provide additional system flexibility required to enable the integration of intermittent renewable resources into the generation portfolio.

Public Staff witness Hinton and NRDC/Sierra Club witness Vitolo generally discussed the possibility that future changes to the availability and/or cost of DSM/EE or renewables could delay or replace the need for the Lincoln CT Project. Mr. Kalemba, however, testified in rebuttal that the increase in solar generation, along with volatility of customer demand during peak winter periods, is why the Company is now winter planning. Furthermore, Mr. Kalemba explained that solar does not provide significant capacity during peak winter mornings, and as such the increase in solar generation will have very limited impact on the timing of future resource needs. Mr. Kalemba was also asked about DEC's request for proposals ("RFP") for up to 500 MW of wind resources and testified that a significant amount of wind resources are included in the 2017 IRP Update, but it did not shift the first capacity need beyond 2024.

The Commission finds that Duke Energy Carolinas' need for generation cannot be met exclusively through the combination of renewable resources and DSM/EE and that peaking generation is needed. While N.C.G.S. 62-2(3a) requires evaluation of the full spectrum of DSM and EE, the goal of such an analysis is to ensure that energy planning results in the least cost mix of generation and demand reduction.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 8

The evidence in support of this finding is based upon the verified application and the testimony and exhibits of Duke Energy Carolinas witness Kalemba.

Company witness Kalemba testified to DEC's evaluation of the wholesale market as part of its decision to pursue a CPCN for the Lincoln CT Project. Mr. Kalemba explained that as the industry and the Carolinas transition to a more modern and efficient generation fleet, it requires the adoption of the most recent developments in natural gas turbine technologies. When reviewing the wholesale market, Mr. Kalemba noted that no existing advanced-class CTs are currently in service in the Carolinas. With respect to new construction, the opportunity to partner with Siemens in their development of an advanced-class CT was compared to the cost that would be incurred with other suppliers. To perform this comparison, Duke Energy Carolinas contracted with Burns & McDonnell to conduct a screening level capital cost estimate, included as Appendix A in Landseidel Exhibit 3, for an advanced-class CT at the Lincoln County site. The site-specific evaluation of the advanced-class turbine was developed based on recent similar project cost information and Lincoln County site information provided by the Company. Based on this review, it was determined that Siemens has offered a significant discount compared to market alternatives for the EPC contractor services including supply of the CT. Given the discount and advanced nature of the technology, the Company concluded that wholesale resources could not take the place of the Lincoln County CT Project.

No intervenor raised any issue with regard to the wholesale evaluation, nor did any intervenor submit testimony on these issues. The Commission concludes that it was appropriate for Duke Energy Carolinas to conclude that wholesale options could not reasonably serve the needs to be met by the Lincoln CT Project. In its August 11, 2008 *Order Holding Docket in Abeyance* in Docket No. E-100, Sub 122, the Commission declined to adopt formal procedures for utilities to assess the wholesale market whenever a utility needs additional generation capacity, but previously explained the wholesale evaluation requirement as follows:

> Accordingly, during future CPCN proceedings, the Commission expects the electric utilities to provide evidence of a robust and thoughtful review of opportunities in the wholesale market. The utilities should also employ the use of competitive bidding and/or third party evaluators as necessary and appropriate to instill confidence that their resource selections are in the public interest. At the end of the day, however, it is the utilities' responsibility to balance the sometimes complex and competing issues so that their customers are assured a reliable electricity supply at reasonable cost.

Because of the unique and substantial cost discount and benefits provided by the Lincoln CT Project, the Commission concludes that Duke Energy Carolinas' process to negotiate the EPC agreement with Siemens and the third party cost estimate prepared by Burns & McDonnell for the Lincoln CT Project adequately assures customers of a reliable electricity supply at reasonable cost.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence in support of this finding is based upon the verified application and the testimony and exhibits of Duke Energy Carolinas witness Landseidel.

Company witness Landseidel testified to the comprehensive siting study that Duke Energy Carolinas conducted to determine the optimum siting location for new CT generation, which is further detailed in Landseidel Exhibit 2. The Lincoln County CT Station scored highest on the siting evaluation by a significant margin. On comprehensive site visits and site studies, no significant issues for the addition of a CT unit at the Lincoln County site have been found. In addition to the utilization of the existing switchyard and transmission capacity, the site provides other cost advantages, including existing fuel oil unloading infrastructure and existing natural gas infrastructure. There are also operating cost synergies associated with the adjacent existing CT units.

As part of the siting process for the Project, Duke Energy Carolinas' cultural resources consultant, Brockington & Associates, Inc., conducted an intensive cultural resources survey for the proposed Project. The North Carolina State Historic Preservation Office concurred with the Brockington's assessment that no historic resources would be affected by the project in the letter included as Appendix B-2 to Landseidel Exhibit 2. In addition to the cultural resources study, Duke Energy Carolinas conducted a Probable Visual Effect Analysis to characterize the existing visual conditions within five miles of the proposed Project and to determine the future plant's effects on the scenic quality of the area. The analysis determined the Lincoln County CT Project will have minimal effects on the visual resources and scenic quality of the area surrounding the proposed site.

The Commission concludes that Duke Energy Carolinas conducted a comprehensive siting process and appropriately selected its existing Lincoln CT generation complex as the site for the Lincoln CT Project.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence in support of this finding is based upon the verified application and the testimony and exhibits of Duke Energy Carolinas witness Landseidel and Public Staff witness Metz.

Company witness Landseidel discussed the environmental controls and permitting for the Lincoln CT Project. Operation of the proposed facility will result in the emission of certain pollutants that are regulated by the US Environmental Protection Agency and the State of North Carolina. Operating impacts from these pollutants will be addressed through the North Carolina Division of Air Quality ("DAQ") air quality permit application process. On August 17, 2017, Duke Energy Carolinas submitted a permit application to DAQ requesting a permit to authorize construction and operation of the combustion turbine units and associated ancillary systems. The new unit will be designed to control emissions via combustion controls as well as a dilution air Selective Catalytic Reduction and Carbon Monoxide Catalyst to Best Available Control Technology; however, due to the size and efficiency of the unit and expected hours of operations, the application is expected to trigger New Source Review under the Prevention of Significant Deterioration program requirements. Duke Energy Carolinas anticipates that a final air permit should be issued within twelve months of submitting the application. Continuous emission monitoring systems will be installed on the turbine's exhaust stack.

The site has a Publicly Owned Treatment Works ("POTW") permit with Lincoln County Public Works, and preliminary plans include the installation of an oil/water separator for treatment of all potential oily waste streams and discharge to the POTW. Other liquid waste streams such as gas turbine wash wastewater will be pumped to tank trucks and hauled off-site for treatment. The following permits may be required in addition to those described above: North Carolina Oil Terminal Registration, Department of Environmental Quality and Lincoln County Storm Water permits, Division of Energy, Mineral and Land Resources Erosion and Sedimentation Control permit, Lincoln County Building permit, and Lincoln County Occupancy permit.

Public Staff witness Metz testified that on August 7, 2017, the State Clearinghouse filed comments in this docket that no further State Clearinghouse review action was needed for compliance with the North Carolina Environmental Policy Act.

No intervenor raised any issue with regard to the environmental impacts from the design of the Lincoln CT Project, nor did any intervenor submit testimony on these issues. The Commission concludes that Duke Energy Carolinas has considered environmental impacts from the Lincoln CT Project as part of the Project design and operation, and that necessary environmental permitting is subject to the jurisdiction of other State agencies.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence in support of this finding is based upon the verified application and the testimony and exhibits of Duke Energy Carolinas witnesses Landseidel and Kalemba and Public Staff witness Metz.

Duke Energy Carolinas submitted confidential cost estimates for the Lincoln CT Project under seal pursuant to N.C. Gen. Stat. §132-1.2 in Landseidel Confidential Exhibit 3. Public Staff witness Metz testified that the overall cost estimate for the Lincoln CT Project appears reasonable. Although Mr. Metz discussed some concerns about some discrete components of the Company's cost estimate, Mr. Landseidel responded and addressed these in detail in his rebuttal testimony. The independent cost estimate prepared by Burns & McDonnell further validates the significant discount that DEC negotiated with Siemens in the firm-price EPC agreement for the Lincoln CT Project.

No intervenor raised any issue as to the Company's cost estimates or submitted any evidence on this point. The Commission finds that the Company has reasonably forecasted the costs associated with the Lincoln CT Project vis-a-vis other alternatives, as discussed in the testimony of Company witness Kalemba and the Duke Energy Carolinas 2016 IRP, and the cost estimate for the Lincoln CT Project is reasonable and is hereby approved. The Company shall update the cost estimates during construction on an annual basis as required by N.C.G.S. 62-110.1(f).

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 12

The totality of the record before the Commission, and the evidence cited in support of the previous findings, demonstrates that construction of the Lincoln CT Project is required by the public convenience and necessity. The purpose of requiring a CPCN before a generating facility can be built is to prevent costly overbuilding. State ex rel. Utilities Commission v. High Rock Lake Association, 37 N.C. App. 138, 141 (1978). What is essential is establishing the element of public need for the proposed service. Id. In the present case, it has been demonstrated that the State of North Carolina, and Duke Energy Carolinas' customer base, is growing, while at the same time the Company is retiring older, less efficient coal units. In order to continue to reliably meet the growing power supply needs of the State, and to continue to provide electricity at reasonable prices as is critical for the economic development and well-being of our citizens, Duke Energy Carolinas must take steps now to begin to ensure the possibility that the Lincoln CT Project is commercially available in 2024. The unique opportunity and compelling benefits presented by the partnership to host the first Siemens advanced-class CT unit, which is scheduled to begin providing electricity for the benefit of DEC's customers in 2020 and continuing during the extended commissioning, testing and validation period from 2020-2024 when the unit will progress from Version A to B to C, are in the public interest and further support the public need for the Project. But for the extended commissioning, testing and validation period and the associated terms negotiated with Siemens, DEC and its customers would not enjoy the substantial benefits and significantly reduced costs of the Lincoln CT Project when needed in 2024. Additionally, the Lincoln CT Project will bring economic development and new jobs to Lincoln County and Mecklenburg County and future regional economic benefits from the design and manufacture of the Siemens advanced-class turbines at its Charlotte manufacturing facility. The development of a Siemens advanced-class turbine will also support the entry of an additional advanced-class turbine market supplier to compete with the two existing suppliers, which can provide long-term benefits for DEC customers and the customers of other North Carolina electric suppliers.

The Public Staff proposed two conditions to address the potential timing risks they identified; however, as discussed previously, the Commission does not find these risks to be wholly persuasive and concludes that with the exception of a hybrid of one of the conditions, the Company has already adequately mitigated these risks through the cost and various provisions negotiated with Siemens, as well as the unprecedented benefit that DEC customers will receive free capacity and energy during the four-year testing and validation period prior to DEC assuming care, custody and control in 2024. In addition, the Commission has sufficient authority in Chapter 62 to protect ratepayers from bearing excessive costs should they arise due to the extended construction period.

The Public Staff's first proposed condition would have delayed DEC's ability to seek cost recovery or request any deferral until the latest of the following three dates: December 1, 2024; the date by which DEC has taken care, custody and control and placed the unit into commercial operation; or the date DEC's 2017-2021 IRP shows a need for the Lincoln CT Project as long as such date is within two years of the date the IRP is approved; along with a requirement for DEC to run a new IRP/CPCN analysis for the Lincoln CT Project every year. The Commission finds that DEC has agreed that it will not seek to recover the capital costs in rates until it assumes care, custody and control of the unit and it goes into commercial operation, even if that date turns out to be later than 2024. Therefore, the Commission will condition the CPCN by prescribing the timeframe for which DEC may seek cost recovery associated with the project. The earliest date DEC can seek cost recovery for the Lincoln CT Project is December 1, 2024, which is the projected date the project will be completed and place into service. This trigger date ensures that ratepayers will not begin paying for the facility prior to the date its capacity is needed, even if construction is completed early and DEC takes possession and commences operations. In the event the Project is delayed beyond December 1, 2024, DEC would be prohibited from seeking rate recovery until it has both actually taken care, custody, and control of the Project and has placed it into commercial operation. This would ensure that ratepayers will not be saddled with costs of the Project before it becomes used and useful. Witness Kalemba testified that these two trigger dates are consistent with the commitments DEC has already made with respect to the Project.

However, with respect to the third proposed trigger date advocated by the Public Staff, the Commission finds such a condition is unnecessary and unduly burdensome. The Commission finds that with this condition, the Public Staff has proposed that the Company essentially re-run the CPCN and IRP analysis each year, which the Commission concludes is unduly burdensome and unnecessary, especially in light of the overwhelming benefits and positive PVRR analysis which support the decision for the Lincoln CT Project CPCN. Furthermore, the Commission already has the authority under N.C.G.S. 62-110.1(e1) to review a CPCN and modify or even revoke a certificate if the Commission finds that completion of the generation facility is no longer in the public interest.

The Public Staff's second proposed condition asks the Commission to find DEC's construction cost estimate to be reasonable, but also find that there shall be a rebuttable presumption that any costs exceeding the total estimated project costs of **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** are unreasonable or imprudently incurred and shall not be recoverable. The Commission finds such a condition to be unnecessary. First, cost recovery issues for the capital costs of new generation facilities are determined in a general rate case pursuant to N.C.G.S. 62-133, and the Commission's approval of a CPCN and its underlying cost estimate as reasonable does not constitute approval of the final costs associated therewith and is without prejudice to the right of any party to take issue with the treatment of the final costs for ratemaking purposes in a future proceeding. The Commission finds no compelling reason or legal authority to change its longstanding practice of not addressing ultimate cost recovery issues in the context of a CPCN proceeding as the Public Staff would have us do. Second, N.C.G.S. 62-110.1(f) already requires all utilities to file an annual construction progress report and any revision to the construction cost estimate during construction, so the Commission, Public Staff and other parties will be aware of any revisions to the cost estimate during construction of the Lincoln CT Project. This statutory provision reflects the understanding that cost estimates are subject to change, upward or downward. Furthermore, although DEC has negotiated a very favorable cost under the EPC Agreement with Siemens, there could be any number of valid reasons why the final costs of the Lincoln CT Project or any multi-year generation facility construction project could potentially exceed that which is projected now or at the time of the CPCN proceeding, and yet still be reasonable and prudent costs that should be recovered from customers. Accordingly, such decisions should be made in the context of a general rate case, where Duke Energy Carolinas will have the burden of proof as to recovery its costs. The Commission is satisfied that there are safeguards in the North Carolina General Statutes that provide tools and mechanisms to allow the Commission to protect customers when DEC ultimately seeks cost recovery for the Lincoln CT Project, and the Public Staff's proposed conditions are not necessary.

The Commission notes that it retains full jurisdiction and authority to disallow any portion of costs associated with the Lincoln CT Project irrespective of any conditions imposed in this case. The Commission's authority is established throughout Chapter 62 of the General Statutes. Specifically, G.S. 62-133(b)(1) prescribes that public utility property must be "used and useful" or "used and useful within a reasonable time after the test period." See State ex rel. Utils. Comm'n v. Carolina Water Service, Inc. of North Carolina, 328 N.C. 299 (1991) (affirming Commission's decision to only include the used and useful portion of utility investment in rate base) and State ex rel. Utils. Comm'n v. Carolina Water Service, Inc. of North Carolina, 335 N.C. 493 (1994) (holding costs of plant determined not used or useful should not be included in rate base). North Carolina General Statutes 62-133(d) requires the Commission to "consider all other material facts of record that will enable it to determine what are reasonable and just rates." The Commission has exercised its authority to disallow cost recovery in instances where plant was not used and useful or costs were unreasonable or imprudent.

While the Commission retains full jurisdiction and authority to disallow costs associated with the Lincoln CT Project during a general rate case, the Commission also possesses authority to impose conditions on utilities to help protect ratepayers against possible risks. This Commission has imposed, as conditions to CPCNs, requirements to retire generation units;[1] to investigate retrofitting coal-burning power plants;[2] to provide progress reports on efforts to work with

[1] Docket Nos. E-2, Sub 1089, Sub 1066 and E-7, Sub 791 and Sub 832.

[2] Docket No. E-2, Sub 1089.

ratepayers to reduce peak load through DSM, EE or other measures and on efforts to site solar and storage capacity;[1] to prohibit the beginning of construction until the Commission has reviewed certain plans and site layouts filed after the issuance of the CPCN;[2] and to file a plan to retire additional unscrubbed coal-fueled generating capacity reasonably proportionate to the amount of incremental generating capacity authorized by the CPCN above the amount of capacity required to be retired as a condition to the CPCN[3]. In these cases, the Commission has exercised its authority as it considers appropriate to impose conditions to address uncertainty and ensure that the CPCN is executed as proposed by the applicant and in the manner the Commission intends.

As a condition of granting the CPCN in the present case, if the Company requests ongoing review pursuant to G.S. 62-110.1(f) or if the Commission conducts ongoing review by its own motion, the costs of the Lincoln CT shall still be subject to the Commission's authority to disallow any portion of the costs under a used and useful review in a future rate-making proceeding once the Lincoln CT is placed fully in service and as long as the capacity of the CT is not utilized at its intended full capacity, irrespective of G.S. 62-110.1(f1). This condition is in addition to the Company's commitment that it will not seek recovery of capital costs in the plant until it is completed.

In the presentation of its case, the Company acknowledged the Public Staff and NRDC/Sierra Club's concerns that there are uncertainties as to many future factors, including possible changes to future costs, technology advancements, and load growth, DR, EE, battery storage, etc., that could impact the timing and need for the Lincoln CT Project in the future. Such uncertainties are present in every CPCN proceeding, and decisions must be made years in advance of projected IRP capacity needs in order to plan for and provide for a reliable and economic supply of energy for North Carolina. The Company's IRP anticipates these factors and takes them into account. Nevertheless, the Commission agrees with the Public Staff that the unique features of this request, including the long-lead time and experimental nature of this project require an extra measure of scrutiny. The Commission determines that it will monitor the progress of this project more closely than it has in past cases and will make any adjustments necessary, including disallowing costs or future cost estimates that are unreasonable or imprudent, to protect Duke Energy Carolinas' ratepayers from excessive costs. Based upon the best information now available to the Company, and for all the foregoing reasons carefully considered and discussed by the Commission in this Order, the Commission concludes that Duke Energy Carolinas has met its burden of showing that construction of the Lincoln CT Project is in the public convenience and necessity.

The Company has the obligation to submit annual progress reports during construction pursuant to N.C.G.S. 62-110.1(f), as well as annual resource plans and updates pursuant to

[1] F

[2] In the Matter of Application of Pantego Wind Energy LLC For a Certificate of Public Convenience and Necessity to Construct a Wind Facility of up to 80 MW in Beaufort County and Registration as a New Renewable Energy Facility, Docket No. EMP-61, Sub 0, Order Granting Certificate and Accepting Registration dated March 8, 2012.

[3] In the Matter of Application of Progress Energy Carolinas, Inc. for a Certificate of Public Convenience and Necessity to Construct a 950 Megawatt Combined Cycle Natural Gas Fueled Electric Generation Facility in Wayne County Near the City of Goldsboro and Motion for Waiver of Commission Rule R8-61, Docket No. E-2, Sub 960, Order Granting Certificate of Public Convenience and Necessity Subject to Conditions, dated October 22, 2009.

Rule R8-60, and this Commission will be kept apprised of any developments that could influence the need for and timing of the Lincoln CT Project. Duke Energy Carolinas' decision to pursue the CPCN for the Lincoln CT Project for the benefit of its customers is prudent and is approved. Finally, the Commission takes note of the unique circumstances that drive the timing of this application. Duke Energy Carolinas wishes to participate in the development and field validation of an advancement in technology that, if proven, can offer substantial cost benefits not only to its own ratepayers but also to the broader marketplace. This is commendable, and the Commission believes that it is in accord with the general policy goals expressed in G.S. 62-2(a)(6). However, the Commission cautions that there must be no presumption that the risks inherent in such development ventures will entirely be shouldered by ratepayers instead of the Company's shareholders. In addition, the circumstances concerning the timing of and the justification for the Company's participation in this project are, if not unique, certainly exceptional. As explained earlier, several factors peculiar to this Project differentiate it from other applications recently disapproved or disallowed by Commission The Commission therefore cautions that this Order should not and cannot be given weight as precedent in any future application by the Company or by other regulated public utilities subject to the Commission's jurisdiction.

IT IS, THEREFORE, ORDERED:

1. That the Application filed in this docket should be, and the same hereby is, approved and a Certificate of Public Convenience and Necessity for the nominal 402 MW Lincoln County CT Project and associated transmission lines is hereby granted with the condition that DEC will not seek cost recovery before the later of December 1, 2024, or the date by which DEC has taken care, custody and control and placed the unit into commercial operation, and this Order shall constitute the certificate;
2. That because the Lincoln CT Project will be built as progressive advanced-class versions A (369 MW), B (382 MW), and C (402 MW), and is subject to potential final configuration as Version A, B or C or as two F-class CTs (468 MW) under the EPC agreement with Siemens, the approval granted by this Order shall apply to the progressive and final version of the unit or units as set forth herein;
3. That Duke Energy Carolinas shall construct and operate the Lincoln County CT Project in accordance with all applicable laws and regulations, including the provisions of all permits issued by the North Carolina Department of Environmental Quality;
4. That Duke Energy Carolinas shall file with the Commission in this docket a progress report and any revisions in the cost estimates for the CT on an annual basis, with the first report due no later than one year from the issuance of this Order;
5. That for ratemaking purposes, the issuance of this Order and CPCN does not constitute approval of the final costs associated therewith, and that the approval and grant is without prejudice to the right of any party to take issue with the treatment of the final costs for ratemaking purposes in a future proceeding; and
6. That for ratemaking purposes, even if the costs for the CT are subject to ongoing review per DEC's request or by the Commission's own motion, the Commission shall still retain the authority to disallow any portion of the costs under a used and useful review in a future rate-making proceeding. Without limitation on the foregoing, in the event the Commission may later find that changes from the Company's forecasts in its 2016 and 2017 Integrated Resource Plans with respect to actual loads and projected load

growth, the utilization of energy efficiency and demand side management measures, the penetration and reliability of renewable resources, the Company's actual mix of generation resources, the Company's reserve margins, or any combination of such factors does not warrant a need for the Lincoln County CT Project until a time later than the winter of 2024-25, the Commission may require that the Company defer recovery for some or all of the costs of the Project until such need is demonstrated by the Company's most recently approved Integrated Resource Plan.

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of December, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

ELECTRIC – ELECTRIC TRANSMISSION LINE CERTIFICATE

DOCKET NO. E-2, SUB 1128

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Progress, LLC, for a Certificate of Environmental Compatibility and Public Convenience and Necessity to Construct Approximately 1.5 Miles of New 230-kV Transmission Line in Johnston County, North Carolina	)	ORDER GRANTING CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AND PUBLIC CONVENIENCE AND NECESSITY

BY THE COMMISSION: On December 1, 2016, Duke Energy Progress, LLC (Duke Energy Progress or DEP) filed an application and direct testimony, pursuant to G.S. 62-100 et seq. and Commission Rules R1-5 and R8-62, for a Certificate of Environmental Compatibility and Public Convenience and Necessity (Certificate or CECPCN) authorizing the construction of a new 1.5 mile 230-kilovolt (kV) transmission line in Johnston County, North Carolina, near the Town of Clayton.

On January 6, 2017, the Commission issued an Order Scheduling Hearings, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice (Scheduling Order). The Scheduling Order, among other things, scheduled a public witness hearing on DEP's application to be held in Smithfield, Johnston County, on Tuesday, March 14, 2017, and an expert witness hearing to be held in Raleigh on Wednesday, March 15, 2017. Further, the Scheduling Order required DEP to publish a Public Notice containing a summary of its application, the details of the public witness hearing, and other information. The Scheduling Order and the Public Notice provided, however, that the hearing might be canceled if no significant protests were filed with the Commission.

On February 14, 2017, the State Clearinghouse filed comments with the Commission stating that because of the nature of the comments, no further review is needed by the Commission to determine compliance with the North Carolina Environmental Policy Act.

On February 15, 2017, DEP filed an affidavit of publication demonstrating that the public notice had been published once a week for four weeks in the Clayton News-Star and the News and Observer (Raleigh).

On February 24, 2017, the Public Staff filed a letter stating that it investigated the application filed by DEP, determined that the proposed transmission line meets the requirements of G.S. 62-105, and recommended issuance of the Certificate. In this letter, the Public Staff stated that the line is necessary, the proposed location and estimated costs are reasonable, the impact of the line on the environment is justified considering the state of available technology, and the environmental compatibility and public convenience and necessity requires the construction of the transmission line.

DEP is the only party to file testimony in this docket.

The Commission did not receive any petitions to intervene or protests in this docket.

On March 7, 2017, DEP filed a Motion to Cancel Hearings. In the motion, DEP asserted that DEP and the Public Staff are the only parties to this proceeding, no party opposed approval of the Certificate, and that unless the Commission required DEP's expert witness to testify in person, there appeared to be no necessity to conduct the public hearing scheduled for March 14, 2017, or the expert witness hearing scheduled for March 15, 2017. Further, the Public Staff did not object to DEP's motion.

On March 8, 2017, the Commission issued an Order cancelling the public witness hearing and noting that that the Public Staff had not received any protests regarding the proposed transmission line.

On March 13, 2017, the Commission issued an Order cancelling the expert witness hearing, accepting into the record the testimony, exhibits and affidavits presented, and requiring DEP to file a late-filed exhibit as well as a proposed order on or before April 17, 2017.

On March 22, 2017, DEP filed the late-filed exhibit.

Also on March 22, 2017, DEP and the Public Staff filed a joint proposed order.

Based upon DEP's verified application, the testimony and exhibits received into evidence by Commission order, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Duke Energy Progress is a public utility providing electric 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 G.S. 62-100 et seq. and Commission Rules R1-5 and R8-62, a public utility must receive a Certificate prior to constructing transmission lines above 161 kV in North Carolina.

3. DEP is required by the Federal Energy Regulatory Commission (FERC) to comply with Reliability Standards of the North American Electric Reliability Corporation (NERC). NERC may impose stringent penalties for violations of NERC Reliability Standards.

4. The proposed transmission line would connect the new 230-kV industrial substation located on Novo Nordisk property adjacent to its existing operations to DEP's existing Lee - Milburnie 230-kV transmission line.

5. No party filed testimony or statements objecting to the granting of the Certificate for the transmission line.

6. DEP's assessment of electric energy requirements identified the need to provide additional capacity to serve the greater Powhatan Industrial Area and the Novo Nordisk expansion near Clayton, North Carolina, which will also result in enhanced service reliability for the area.

7. DEP's application meets the requirements of G.S. 62-102.

8. DEP has carried its burden of proof under G.S. 62-105 by showing that:

(1) The proposed transmission line is necessary to satisfy the reasonable needs of the public for an adequate and reliable supply of electricity;

(2) When compared with reasonable alternative courses of action, construction of the transmission line in the proposed location is reasonable, preferred, and in the public interest;

(3) The costs associated with the proposed transmission line are reasonable;

(4) The impact that the proposed transmission line will have on the environment is justified considering the state of available technology, the nature and economics of the alternatives, and other material considerations; and

(5) The environmental compatibility, public convenience and necessity require the construction of the transmission line.

9. It is in the public interest, reasonable and appropriate to grant the requested Certificate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

These findings of fact are essentially informational, jurisdictional, and procedural in nature and are uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-9

The evidence supporting these findings of fact appears in DEP's application, the direct testimony of witnesses William H. Council and Timothy J. Same, the Routing Study and Environmental Report (Report) filed by DEP, the comments of the State Clearinghouse, and the filing of the Public Staff.

On December 1, 2016, DEP filed its CECPCN Application requesting authorization to construct a new 230-kV transmission line in Johnston County, North Carolina. The Application states that DEP is required by the FERC to comply with the NERC Reliability Standards, and that NERC may impose stringent penalties for violations of NERC Reliability Standards.

In accordance with the NERC standards, DEP states that it plans its transmission system to supply projected demands in a reliable manner at all demand levels over the range of forecast system demand, under contingency conditions. DEP states that in compliance with NERC's Reliability Standards, it routinely conducts studies of its transmission system to identify required improvements.

DEP witness William H. Council states that the new transmission line is needed to provide additional capacity to serve the greater Powhatan Industrial Area and the Novo Nordisk expansion near Clayton, North Carolina. Witness Council states that Novo Nordisk has begun construction of an 800,000 square foot campus that will manufacture active ingredients for insulin products used to improve the treatment of diabetes. Witness Council also states that Novo Nordisk has announced that the new plant, when it is operational in 2020, will add about 700 jobs to Novo Nordisk's site in Clayton. Further, according to witness Council, the new transmission infrastructure would provide greater capacity and enhanced service reliability to support the Powhatan Industrial Area, which has been identified by both the Town of Clayton and Johnston County as an area targeted for industrial growth. Initially, the new transmission tap line is intended to serve the 30-MW Novo Nordisk Active Parts Ingredients Manufacturing facility.

DEP's Application states that the proposed transmission line would connect the new 230-kV industrial substation located on Novo Nordisk property adjacent to its existing operations to DEP's existing Lee - Milburnie 230-kV transmission line.

In order to construct the proposed 230-kV transmission line, however, DEP must first obtain a Certificate from the Commission pursuant to G.S. 62-102.

DEP's Application states that the study area is located in east-central North Carolina in Johnston County. The western and southern portion of the study area runs along DEP's existing Clayton Industrial - Milburnie 115kV transmission line. The northern portion of the study area extends just beyond N.C. State Highway 42, and the eastern boundary runs along the existing Lee - Milburnie 230kV transmission line. The study area includes the townships of Clayton and Wilson's Mills and encompasses approximately 10.7 square miles. The study area and regional features are shown in Figure 2-1 of the Report, which DEP attached as Exhibit A to its Application.

DEP's Application states that the preferred route for the transmission line originates at the site of the proposed Industrial Substation on Novo Nordisk property on the east side of a parcel across Powhatan Road from an existing Novo Nordisk facility. The route exits the substation to the south for approximately 1,000 feet before turning southeast and paralleling the north side of an existing Norfolk Southern/Amtrak railroad line for 2,300 feet. The route then turns east for 4,265 feet before angling slightly more northeast for 630 feet before terminating at the existing Lee - Milburnie 230-kV transmission line tap point. This route is 8,196 feet (approximately 1.5 miles) in length and is shown in Figure 4-5 of the Report.

DEP fully described the transmission line routing process, studies and physical properties in the Report. The Report satisfies all of the requirements of G.S. 62-102.

Exhibit B to the Application is a draft public notice summary of the Application. DEP published the public notice, as modified by the Commission's Scheduling Order, in newspapers of general circulation serving the portions of Johnston County impacted by the proposed line. DEP published the public notice upon Commission approval and also served the parties identified in G.S. 62-102(b) with a copy of this Application and a notice stating the date the Application was filed, the date by which parties must seek intervention, and the statute and the rule governing intervention.

DEP witness Timothy J. Same testified that 5 landowners (6 parcels) will be directly affected by having at least some portion of the proposed 125-foot right-of-way on their property. Witness Same testified that on November 4, 2016, DEP sent letters to those property owners, as well, that are within 200 feet (12 landowners of 14 parcels) of the proposed centerline of the preferred route (400 feet total). These letters included the appropriate reference to G.S. 40A-11 providing the necessary 30-day notice to enter the properties for the purpose of surveying, soil borings, appraisals, and assessments.

On February 14, 2017, the State Clearinghouse filed comments with the Commission resulting from routing the application through the State Clearinghouse review process. Based on the nature of the comments, the letter from the State Clearinghouse indicated there was no further action required of the Commission for compliance with the North Carolina Environmental Policy Act. The letter further states that DEP should take all comments provided through the Clearinghouse review into consideration when developing the project.

On February 24, 2017, the Public Staff submitted a letter in support of DEP's Application, stating that DEP has complied with the requirements of G.S. 62-102 and 62-105 and recommending that the requested Certificate be issued.

No party intervened in the docket, and no party or person has objected to the requested Certificate.

Having carefully reviewed the Application, and based on all the evidence of record and the recommendation of the Public Staff, the Commission finds and concludes that the proposed transmission line satisfies the environmental compatibility and public convenience and necessity requirements of G.S. 62-100 et seq., and, therefore, a certificate of environmental compatibility and public convenience and necessity should be issued for the proposed transmission line construction.

IT IS, THEREFORE, ORDERED that pursuant to G.S. 62-102, a certificate of environmental compatibility and public convenience and necessity to construct approximately 1.5 miles of new transmission line in Johnston County, North Carolina, as described in DEP's application, is hereby issued to DEP, and the same is attached as Appendix A.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of April, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1128

KNOW ALL PERSONS BY THESE PRESENTS THAT

DUKE ENERGY PROGRESS, LLC
410 South Wilmington Street
Raleigh, North Carolina 27601

is hereby issued this

CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AND PUBLIC CONVENIENCE AND NECESSITY PURSUANT TO G.S. 62-102

to construct approximately 1.5 Miles of new 230-kV Transmission Line in Johnston County, North Carolina that will originate at the site of the proposed Industrial Substation on Novo Nordisk property on the east side of a parcel across Powhatan Road from an existing Novo Nordisk facility and terminate at the at the existing Lee - Milburnie 230-kV transmission line tap point

subject to receipt of all federal and state permits as required by existing and future regulations prior to beginning construction and further subject to all other orders, rules, regulations, and conditions as are now or may hereafter be lawfully made by the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the _21st_ day of April, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-7, SUB 487
DOCKET NO. E-7, SUB 828
DOCKET NO. E-7, SUB 1026

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Duke Energy Carolinas, LLC, – Investigation of Existing Rates and Charges Pursuant to Regulatory Condition No. 76 as Contained in the Regulatory Conditions Approved by Order Issued March 24, 2006, in Docket No. E-7, Sub 795	)	ORDER APPROVING EDPR RIDER

BY THE COMMISSION: On March 29, 2017, Duke Energy Carolinas, LLC (DEC or the Company), filed a proposed Existing DSM Program Costs Adjustment Rider (EDPR), based on the December 31, 2016, legacy demand-side management (DSM) deferral account balance. The Company requested that the EDPR be effective for the period July 1, 2017, through June 30, 2018.

An EDPR was first proposed in Section 11 of the Agreement and Stipulation of Partial Settlement (Stipulation) entered into by the Company and various parties in DEC's general rate case in Docket No. E-7, Sub 828. The Commission approved the Stipulation in its December 20, 2007, Order Approving Stipulation and Deciding Non-Settled Issues (the Sub 828 Order), and 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 during the then most recent calendar year. During calendar year 2016, the applicable base rate amount was 0.0125 cents per kWh (excluding the North Carolina regulatory fee), as reaffirmed pursuant to the Commission's September 24, 2013, Order in general rate case Docket No. E-7, Sub 1026.

In its March 29, 2017 filing, DEC proposed to replace the existing EDPR decrement rider amount of (0.0050) cents per kWh (excluding the regulatory fee),[1] with a new decrement rider amount of (0.0058) cents per kWh (excluding the regulatory fee), to be effective on and after July 1, 2017.

On June 6, 2017, DEC filed a revised calculation of the EDPR to remove certain costs that are not eligible for recovery in the rider. As a result of this correction, DEC now proposes an EDPR decrement of (0.0057) cents per kWh, excluding the regulatory fee. The base existing DSM program cost amount of 0.0125 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,

[1] The existing EDPR decrement was allowed to become effective as of July 1, 2016, pursuant to Commission Order in these dockets.

including all rate adders, is the difference between the proposed decrement rider, including the regulatory fee, of (0.0057) cents per kWh, and the current decrement rider, including the regulatory fee, of (0.0050) cents per kWh, or a net rate reduction of (0.0007) cents per kWh.

This matter was presented to the Commission at its Regular Staff Conference on June 19, 2017. The Public Staff stated that it had reviewed DEC's calculation of the proposed EDPR, including the supporting workpapers submitted with the initial and revised filings and information provided by DEC in response to Public Staff data requests. Based on its review, the Public Staff concluded that the revised proposed rate decrement is reasonable. Therefore, the Public Staff recommended that DEC's proposed EDPR be approved, effective beginning July 1, 2017.

Based on its review of DEC's filing and the recommendation of the Public Staff, the Commission concludes that the revised proposed EDPR is reasonable and should be approved, effective July 1, 2017.

IT IS, THEREFORE, ORDERED that the EDPR proposed by DEC in its revised filing of June 6, 2017, consisting of a rate decrement of (0.0057) cents per kWh excluding the regulatory fee [(0.0057) cents per kWh, including the regulatory fee], is approved effective July 1, 2017, through June 30, 2018.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of June, 2017.

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 1137

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC,	)	ORDER APPROVING PROGRAM
for Approval of Equal Payment Plan	)	FOR THREE-YEAR TRIAL PERIOD
WeatherProtect Program	)	

BY THE COMMISSION: On February 15, 2017, Duke Energy Progress, LLC (DEP or Company), filed a petition with the Commission for approval of a new voluntary program for residential customers who desire electric bill certainty, the Equal Payment Plan WeatherProtect (EPP WeatherProtect). Similar to DEP's Equal Payment Plan (EPP), EPP WeatherProtect will offer equalized payments each month over a 12-month period and will require a true-up to actual energy usage at year-end. The EPP WeatherProtect monthly payment will be calculated like the

EPP monthly payment, but the customer's true-up amount will be capped at a predetermined level based on the customer's weather-normalized energy usage. In return, EPP WeatherProtect customers will pay a predetermined monthly administrative fee for the certainty provided by the maximum potential true-up cap protection.

DEP states that EPP WeatherProtect customers will benefit in a number of ways. First, customers will know with certainty the maximum amount they will pay each month during the 12-month period. Second, they will no longer be at risk of high monthly electric bills due to factors beyond their control, such as weather variation. Further, DEP states that EPP WeatherProtect will benefit DEP by improving customer satisfaction and reducing inquiries about high bills.

DEP further notes that from March 2004 through November 2012, DEP offered its customers a Balanced Bill Payment Plan (BBP), as approved by the Commission in Docket No. E-2, Sub 847. The BBP allowed customers to pay a fixed monthly bill that included a premium, but did not require a true-up at the end of 12 months. DEP states that the BBP was extremely well received by DEP's customers, and at peak enrollment, in April 2008, over 63,000 customers participated in the plan. However, due to concerns about the impact of BBP on customer energy conservation and peak demand, the Commission issued an order on March 14, 2008, closing the BBP to new applicants, but allowed existing participants to continue to receive this payment option. Due to the continuing and increasing emphasis placed on energy efficiency, DEP terminated the BBP in December 2012.

DEP states that EPP WeatherProtect will provide customers a level of bill certainty, while addressing the issue of increased usage under the BBP due to no price signal. EPP WeatherProtect will be available to residential customers with a satisfactory payment record who have at least 12 months of usage history and participate in DEP's My Home Energy Report Program (MyHER). In addition, the customer must have a consistent usage pattern that supports an accurate forecast of future consumption. The EPP WeatherProtect offer will be for one year's service, renewable by mutual agreement. However, DEP may send warning letters to customers that use 25% more than the expected weather-adjusted energy usage during specified periods, and will have the ability to terminate customers for usage more than 30% of the expected weather-adjusted energy usage during specified periods.

On February 17, 2017, the Commission issued an Order Requesting Comments. On May 1, 2017, the Public Staff filed comments and on May 12, 2017, DEP filed reply comments. On June 20, 2017, DEP filed an updated Exhibit 1, the Residential Service Equal Payment Plan (WeatherProtect) EPPWP-1.

SUMMARY OF COMMENTS

Public Staff

In its comments, the Public Staff discusses DEP's BBP plan approved in 2004, which provided customers with a one-year contracted bill amount in which the monthly bill did not vary. The Company arrived at the contracted bill amount by using 24 months of customer usage data and weather data to project a weather-normalized monthly usage and added a usage adder up to 5.8% and a 4.4% risk premium to the bill. In 2007, the usage adder was reduced to 4.5% for new participants and was reduced to zero for renewal customers that had been on the program for two or more years. The customer's usage was not trued-up at the end of the year; rather, the actual usage amount was used to calculate a new payment for the following year.

In 2007, the Commission issued an order seeking comments on whether PEC's BBP and the similar Fixed Payment Plan (FPP) offered by Duke Energy Carolinas, LLC (DEC), approved in Docket No. E-7, Sub 710, increased energy usage by the participating customers or contributed to each company's peak demand. Both companies responded. Customers enrolled in PEC's BBP used 6.94% more energy in the first year of enrollment, which declines to 2.99% more energy usage than normal for the second year and 1.68% more energy than normal for the third year. DEC's FPP followed a similar pattern. PEC did not have specific data on the BBP's impact on its peak demand, but DEC indicated that two studies showed that FPP customers had an 11% and 31% higher usage, respectively, during peak demand than non-FPP residential customers and concluded that this added load increased the peak by 0.2% and 0.3%, respectively. In an order issued on March 14, 2008, the Commission closed PEC's BBP and DEC's FPP to new customers, concluding that the benefits of the programs did not outweigh the increased energy usage. In October 2011, the Commission issued an order approving PEC's request to terminate its BBP, which PEC ultimately closed on November 20, 2012.

With this background, the Public Staff expresses concerns regarding DEP's proposed EPP WeatherProtect, stating that EPP WeatherProtect has similar characteristics to DEP's BBP and DEC's FPP. Unlike the EPP, EPP WeatherProtect offers customers a predetermined yearly billing cap to protect participants from unforeseen usage abnormalities. The cap is set at the 75th percentile of the customer's expected weather-normalized usage. Thus, at the end-of-the-year true-up, when the next year's monthly bill is set, under EPP WeatherProtect, the true-up adjustment will only true up for usage that is below the 75th percentile of the customer's expected usage. The Public Staff contends the usage above the 75th percentile is presumed to be related to extreme weather and is not taken into account in the true-up adjustment for the next year's monthly bill.

The Public Staff opines that this program will, like DEP's BBP and DEC's FPP, lead to increased usage through a lack of a full true-up and the "credit card effect." The Public Staff states that the credit card effect is a way to increase sales by disconnecting the immediate consumption of the good, which is pleasant, from the payment of the good, which is unpleasant. The Public Staff indicates that there will be a temptation to consume more energy than normal during periods of extreme weather because customer usage that is above the billing cap is not subject to future true-up adjustment.

With respect to the administrative fee, the Public Staff indicates that the Company has stated since its filing that it will set the administrative fee at 3.8% and adjust it in response to how the program is performing over time.

The Public Staff states it has concerns regarding DEP's terms regarding removal of customers from the program. DEP has indicated that it will remove customers from the EPP WeatherProtect during the one-year contract period if a customer's usage is reported to be more than 30% above the expected weather-adjusted energy usage between the third and ninth billing months of the contract billing period. The Public Staff indicates that DEP should be more aggressive and give notice of exceedances to the customers during the contract billing period.

The Public Staff concludes by recommending that the Commission should not approve the program because customers already have a budgeting option through EPP, the program could lead to an increase in usage, the increased usage could negatively impact the cost effectiveness of the MyHER program, and the billing cap was derived from 12 months versus 24 months of historical data.

If the Commission approves the program, the Public Staff recommends the addition of the following conditions: require DEP to provide information comparing the monthly payments and total costs of the EPP and the EPP WeatherProtect programs to the potential program participants; require DEP to issue a warning letter to participants approaching 25% of expected weather-adjusted energy usage and the consequences of potential elimination from the program; require DEP to set the administrative fee at 3.8%, with no amendment without prior Commission approval; require DEP to use 24 months, as opposed to 12 months of historical data, to set the initial billing cap amount for each participant; require DEP, if possible, to, in the EM&V reports for the MyHER program, distinguish energy savings impacts for EPP WeatherProtect participants from the general population of MyHER participants; require DEP to provide semi-annual reports providing: total number of EPP WeatherProtect customers, number of participants that reach the usage cap, energy consumed by the participants, bill total, difference between an EPP WeatherProtect bill and actual bill amount; number of participants who leave the program (voluntary and terminations), year-to-date totals for all of the above data, and an analysis of the energy usage dates of the participants as compared to the predicted weather normalized energy consumption.

<u>DEP's Reply</u>

DEP responds to the first concern of the Public Staff, which is that customers already have a budgeting option through EPP, by explaining that EPP WeatherProtect is not a new program to give customers a new budgeting option, but rather, it is a voluntary enhancement to the existing EPP budgeting option, designed to ease concerns about the impact that extreme weather could have on a future bill.

The second concern of the Public Staff is that the EPP WeatherProtect, like the past BBP, could increase customer usage. DEP responds by stating that EPP WeatherProtect is different than the BBP because customers under EPP WeatherProtect can see a direct correlation of the impact that increases and decreases in consumption will have on the EPP monthly bill for the next billing year. A customer whose usage increases will see all of the increase up to the point of the EPP WeatherProtect cap in the following year's EPP monthly bill. DEP provides an attachment to visualize the comparisons.

DEP indicates that another significant difference between BBP and EPP WeatherProtect is the fact that DEP is requiring that the customer participate in the MyHER energy efficiency program. Customers of the MyHER program are actively engaged in their energy usage and have a means to see if energy usage has changed. Further, DEP indicates that lost revenues the Company is allowed to recover would be reduced if usage increased due to EPP WeatherProtect, as well as the portfolio performance incentives contained in its energy efficiency and demand-side management rider, would also be reduced.

In response to the "credit card effect" argument, DEP argues that almost all DEP customers pay for their usage after they have consumed it at the end of the billing cycle, and the current EPP customers have the same disconnect except for the true-up at the end of the 12-month period. DEP contends that the EPP WeatherProtect does not exacerbate the existing disconnect between the consumption transaction and the payment transaction. Further, DEP states that a 2009 study in New Zealand demonstrates that customers may actually spend less with a credit card than with cash.

The third concern of the Public Staff is that the EPP WeatherProtect could negatively impact the cost effectiveness of the MyHER program. In addition to its comments from the previous section, DEP states that because of the deliberate design of the EPP WeatherProtect program, the Company contends that EPP WeatherProtect will not increase usage and the Company will ensure that the MyHER program's overall cost effectiveness is not jeopardized by EPP WeatherProtect.

The final concern of the Public Staff is that DEP uses 12 months versus 24 months of historical data in determining the EPP WeatherProtect cap. DEP indicates that the 12 months is a minimum amount of historical data to be used and that, if available, it will use up to 48 months of historical data in establishing the cap. Further, the 12 month minimum is consistent with EPP for establishing the monthly billing amount, and EPP WeatherProtect is a voluntary enhancement to the existing EPP.

With respect to the conditions that Public Staff has requested if the Commission approves the program, DEP indicates that it is generally supportive of the recommendations with the exception that the Company require 24 months of historic usage data for a customer to participate in EPP WeatherProtect. DEP agrees to provide semi-annual reports to the Public Staff using the tracking report attached hereto as Attachment B.

DEP requests that the Commission approve EPP WeatherProtect for a three-year trial period, instead of accepting the Public Staff's recommendation not to approve EPP WeatherProtect.

DISCUSSION AND CONCLUSIONS

Based upon the petition and comments provided in this docket, the Commission approves EPP WeatherProtect for a three-year trial period as proposed by DEP in its reply comments. While the Commission finds that the Public Staff's concerns regarding the possibility of increased customer usage and that this increased customer usage could negatively impact the MyHER program have merit, the Commission finds DEP's reply comments persuasive enough to approve the program for a three-year trial period.

The Commission does not fully agree with all of DEP's arguments regarding the Company's BBP program and its lack of impact on a customer's monthly bill calculation for the following year. However, the Commission agrees that the EPP WeatherProtect is different enough from the BBP that it may successfully address the Public Staff's concerns. The Commission agrees with DEP that customers of EPP WeatherProtect, which only protects a customer from possible extreme weather usage, are still incentivized to reduce consumption to have a lower monthly bill the following year. This deliberate design improvement may be all that is needed for DEP to address and correct the Public Staff's increased energy usage concern, and still be able to provide customers bill certainty and improve customer satisfaction.

On a tangential note, the Public Staff indicated in its comments that it could not find a Commission order approving the EPP program. DEP has indicated to the Public Staff and the Commission that the predecessor to DEP, Carolina Power & Light Company, may have relied upon Commission Rule R8-44(5) to allow this option without Commission approval. The Company also sent a letter to the Commission dated November 26, 1980, providing the Commission with a Revised Equal Payment Plan which became effective January 1, 1981. The letter and document are attached as Attachment C. The Commission is satisfied that, based upon the foregoing, the initial EPP program received Commission approval.

Therefore, based upon DEP's petition and the comments received, the Commission is of the opinion that the EPP WeatherProtect program should be approved with specific conditions as outlined below for a three-year trial period. The Commission concludes that this trial period allows the Commission, the Company and the Public Staff ample time to evaluate the impact the program has on customer consumption and the Company's peak load.

IT IS, THEREFORE, SO ORDERED as follows:

1. That the EPP WeatherProtect program attached hereto as Attachment A is hereby approved effective August 1, 2017, for a three-year pilot program.

2. That DEP shall provide clear marketing materials and consult with the Public Staff prior to issuance.

3. That DEP shall send a warning letter to customers if during periods 2 and 8 months the customer's usage is 25% more than their expected weather-adjusted energy usage and shall consult with the Public Staff regarding the wording of the proposed letter.

4. That DEP will set the administrative fee at 3.8% and will not amend the fee without first seeking Commission approval.

5. That DEP will work with the third-party EM&V evaluator for the MyHER program to, if possible, distinguish the program's impact on EPP WeatherProtect customers from the non-EPP WeatherProtect customers.

6. That any uncollected bill amounts for energy usage above the cap for participants of EPP WeatherProtect shall be covered by the shareholders of DEP.

7. That DEP shall provide semi-annual reports to the Public Staff and annual reports to the Commission using the tracking report attached hereto as Attachment B.

8. That DEP and the Public Staff report to the Commission, three months before the end of the trial period, whether the program should become a permanent program.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of July, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Daniel G. Clodfelter did not participate in this decision.

Duke Energy Progress,
LLC (North Carolina
Only)

Attachment A

RESIDENTIAL SERVICE
EQUAL PAYMENT PLAN (WEATHERPROTECT) EPPWP-1

AVAILABILITY

Equal Payment Plan (EPP) WeatherProtect is available on a voluntary basis, at Company's sole option, to customers served on Residential Service Schedule RES. The plan offers customers a levelized monthly bill for 12 months with an annual true-up at year-end. The amount of the annual true-up is limited by an annual kWh billing cap that factors in the kWhs used by the customer for the last 12 months.

To qualify for service under the Plan, Customer must have resided at the current dwelling unit and have kilowatt-hour (kWh) usage history for twelve (12) consecutive months, must have a consistent usage pattern that supports an accurate forecast of future consumption, and must have demonstrated a satisfactory payment record. The customer must also participate in the Residential Service My Home Energy Report Program RS-HERP while receiving service under this payment plan.

EPP WEATHERPROTECT MONTHLY BILLING

EPP WeatherProtect Monthly Billing shall be the sum of (1) a Monthly Bill Amount, (2) a Monthly Administrative Charge and (3) a True-Up Charge of prior period payments which are determined as follows:

Monthly Bill Amount:
The Monthly Bill Amount is based on the last 12 months of energy charges. The sum of the past 12 months' monthly energy charges will be divided by 12 to establish a Monthly Bill Amount. The Monthly Bill Amount also includes the True-Up Charge as defined below for renewals.

Monthly Administrative Charge:
The Monthly Administrative Charge is calculated as a designated Administrative Charge Percentage times a weather normalized monthly bill amount, calculated for the customer. The Administrative Charge Percentage will not exceed 3.8%.

True-Up Charge:
The True-up Charge shall be calculated as the difference between Customer's past 12 months' Monthly Bill Amount, exclusive of any payments associated with the Monthly Administrative Charge or prior period True-Up Charges, and billing for actual usage under Schedule RES. The difference shall be limited by a True-Up kWh Billing Cap which limits the number of kWhs billed for usage during the past 12 months. The True-Up Billing Cap is determined on a customer-specific basis reflecting Customer's expected load response to weather extremes and is provided to Customer with the initial or renewal quote. The resulting difference will be divided by 12 and will be included within the Monthly Bill Amount.

The EPP WeatherProtect Monthly Bill will be paid in lieu of the normal monthly charges for actual kilowatt-hours used as calculated on Schedule RES. The monthly charge will not include usage or charges for additional services including, but not limited to, area lighting, but will include any discounts received under Company's Residential Service Energy Conservation Discount Rider RECD, if applicable. The provisions of Residential Service Schedule RES are modified only as shown herein.

RENEWABLE ENERGY PORTFOLIO STANDARD (REPS) ADJUSTMENT

The monthly bill shall include a REPS Adjustment based upon the revenue classification:

Residential Classification - $1.17/month

Upon written request, only one REPS Adjustment shall apply to each premise serving the same customer for all accounts of the same revenue classification. If a customer has accounts which serve in an auxiliary role to a main account on the same premise, no REPS charge should apply to the auxiliary accounts regardless of their revenue classification (see Annual Billing Adjustments Rider BA).

CONDITIONS OF EPP WEATHERPROTECT OFFER

Company shall provide to new and existing participants: the EPP WeatherProtect Monthly Bill, including the Monthly Bill Amount; Monthly Administrative Charge; and the True-Up kWh Billing Cap.

CONTRACT PERIOD

Service under this payment plan shall commence with the first billing period of the Contract Year for a minimum one-year term, renewable annually at the option of both parties. A new Plan contract and amount will commence each successive Contract Year unless terminated by Customer or Company.

TERMINATION PROVISIONS

Customer may terminate participation under EPP WeatherProtect by giving Company a minimum of 30 days prior notice. Company may terminate the Plan if Customer's actual usage in months three (3) through nine (9) of the contract year exceeds 30% of normalized monthly usage or for any other violation of this plan. If this Plan is terminated by Customer or Company at any time during a Contract Year, any existing credit or debit balance, will come due at the time of termination. Any Monthly Administrative Charges payments received will not be included in the determination of the credit or debit balance if Customer requests termination of the Plan.

Effective for bills rendered on and after______, 2017
NCUC Docket E-2, Sub 1137

DEP EPP WeatherProtect Tracking Report

Attachment B

Duke Energy Proposal – Semi-Annual Reporting

Description	For the Six Months Ending June 30th (or December 31st)
Number of new enrolling EPPWP customers	Number of customers
Number of re-enrolling EPPWP customers	Number of customers
Number of EPPWP customers leaving the program (voluntary or terminations)	Number of customers
Total number of EPPWP customers	Number of customers
For all customers completing their one-year EPPWP contract period:	
Actual kWh consumed by EPPWP customers	total kWh
Predicted weather normalized kWh consumed by EPPWP customers before enrolling (12 months)	total kWh
Predicted weather normalized kWh consumed by EPPWP customers after enrolling (12 months)	total kWh
Variance of weather normalized kWh consumed for EPPWP customers between before and after enrolling	kWh
Percentage change in energy consumption = variance ÷ before enrolling kWh consumed	% change
Number of EPPWP customers reaching their billing cap	number of customers
Total service charges collected from EPPWP customers	total dollars
Total bill coverage provided by Duke Energy for EPPWP customers exceeding their billing cap	total dollars

Attachment C

CP&L

Carolina Power & Light Company

P. O. Box 1551 • Raleigh, N. C. 27602

NORRIS L. EDGE
Manager
Rates and Service Practices

November 26, 1980

Ms. Sandra J. Webster
Chief Clerk
North Carolina Utilities Commission
PO Box 991
Raleigh, NC 27602

Dear Ms. Webster:

RE: REVISED EQUAL PAYMENT PLAN

Enclosed herewith is a copy of the revised Equal Payment Plan for Carolina Power & Light Company. The plan has been revised in order to better assist customers in levelizing their power bills over a 12-month period. The plan has also been revised to provide a tracking system to better inform customers of their account status and to help prevent a large variation between customer payments and actual account billing. Additionally, the plan has been revised to eliminate the use of a "settle-up month" at the end of the equal payment plan year that would require a customer to make a one-time payment. This will avoid the inconvenience that sometimes occurs when customers accumulate a large balance due amount that becomes payable at the year's end. The details of this program are defined in the attached document.

Carolina Power & Light Company plans to implement the revised program on January 1, 1981, in order to make it available to customers for their winter bills. If there are any questions, or if further information is required, please let us know.

Very truly yours,

Norris L. Edge

Norris L. Edge

NLE/dt

Attachment

EQUAL PAYMENT PLAN

CAROLINA POWER & LIGHT COMPANY

The Equal Payment Plan (EPP) is a billing procedure that is made available to residential customers to assist them in their budget planning by levelizing their monthly power bills over a twelve month period. This procedure incorporates a tracking mechanism that continuously compares customers' actual billing to estimated billing to prevent a large variation from occurring between actual billing and EPP billing. The procedure eliminates the need for a "settle-up month" that could require a customer to make a large one-time payment at the end of the EPP year. Following is a description of the Equal Payment Plan.

Calculating Initial EPP Amount

Method of Calculating EPP Amount

The following steps are used to calculate the initial EPP Amount:

Step 1. Add the 12 most recent monthly bill amounts (current and previous 11 months) to determine the actual annual billing for electric service for the past year.

Step 2. Determine the estimated annual amount to be billed for underground services, area lighting and residential subdivision street lighting service or other miscellaneous charges which are not included in Step 1. (This estimate is based on charges for services that are present at the time the calculation is made.)

Step 3. Add Steps 1 and 2 to determine the estimated annual billing.

Step 4. Multiply the estimated annual billing by the inflation adjustment factor (currently 1.08) to determine the total estimated annual billing for the ensuing year. The billing adjustment factor is based upon historical data and is intended to adjust a customer's historical billing to better reflect current day pricing. This factor will be changed periodically as necessary to reflect current rate and usage patterns.

Step 5. Add to the total estimated annual billing in Step 4 any account balance to be carried forward and to be included in the next twelve months' EPP amount.

Step 6. Divide the total determined in Step 5 by 12 and round to the nearest whole dollar to determine the monthly EPP amount.

<u>Example:</u>

\$480.86	– 12 most recent bill amounts
+ 71.52	– Miscellaneous charges (Area Light)
\$552.38	– Estimated annual billing
x 1.08	– Projected rate with 8% inflation factor
596.57	– Total Estimated Annual Billing
+ 45.31	– Account balance to be included
\$641.88	– divided by 12 = \$53 = EPP Amount

NOTE: An EPP amount for customers having 12 months history will be calculated by the computer and will be available to the appropriate field office on the computer informational display screen; however, the computer calculation does not include account balances which may be carried forward. If an account balance is to be included, the field office will adjust the EPP amount accordingly.

Estimated EPP amounts for customers with less than twelve months' history must be manually calculated by the field office.

Introduction of EPP

To introduce the new EPP, bill inserts explaining the program will be included in each residential customer's bill in the months of January and February, 1981. In addition, a caption will be printed on each customer's bill to call attention to the insert.

Customers having a balance forward and/or less than twelve months history will receive bills reflecting a caption similar to "REFER TO ENCLOSED INFORMATION FOR DETAILS ON NEW EPP PLAN." Interested customers must contact their local CP&L office to obtain their estimated EPP amount and other details concerning the plan.

Customers having twelve months' history and no debit or credit balance will receive bills reflecting a caption similar to "YOUR ESTIMATED EPP AMOUNT IS XXX.XX - YOU MAY BECOME AN EPP CUSTOMER BY PAYING XXX.XX - SEE ENCLOSED INFORMATION." For these customers the EPP amount is calculated by the computer automatically and the customer will automatically be placed on EPP upon payment of the EPP amount. If the customer does not pay the EPP amount, he will not be placed on the plan and the monthly billing will remain unchanged. The month following payment of the initial EPP amount, a caption similar to "THANK YOU FOR SELECTING THE EPP PLAN" will be printed on the customer's bill to notify him that he is now on EPP.

Monthly EPP Review

All accounts billed under the EPP plan are reviewed each month by the computer to determine the account status and to prevent a large variation between customer's actual billing and EPP billing. When it is determined that a customer's EPP amount requires alteration, the customer will be notified of any necessary changes.

Written Agreement

Effective with the implementation of the new EPP plan, a written agreement for the plan is no longer required. The customer's verbal request or implied acceptance through payment of the EPP amount will be accepted in lieu of a signed agreement.

Termination of EPP

Once a customer has elected to be placed on the Equal Payment Plan, his monthly bills will be prepared in accordance with the provisions stated above. The Equal Payment Plan may be terminated by the customer or Company by notifying the other party. Upon termination, any credit due the customer will be refunded or any amount due the Company will become payable at that time. In the event of non-payment of any monthly equal payment bill when due, the Company may terminate the plan with that customer and take any collection action for the amount due that is in accordance with its Rates and Service Regulations governing non-payment of bills.

DLT

DOCKET NO. E-2, SUB 1095
DOCKET NO. E-7, SUB 1100
DOCKET NO. G-9, SUB 682

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Corporation and Piedmont Natural Gas, Inc., to Engage in a Business Combination Transaction and Address Regulatory Conditions and Code of Conduct	)))))	ORDER APPROVING MODIFICATIONS TO WORKFORCE DEVELOPMENT AND COMMUNITY SUPPORT FUNDING PROCESS

BY THE COMMISSION: On September 29, 2016, the Commission issued an Order Approving Merger Subject to Regulatory Conditions and Code of Conduct (Merger Order) in the above-captioned dockets approving the merger of Duke Energy Corporation (Duke Energy) and Piedmont Natural Gas Company, Inc. (Piedmont). The Merger Order includes numerous conditions to be met by Duke Energy, Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), and Piedmont (collectively, Applicants). In particular, Ordering Paragraphs No. 5 and 6 provide:

> 5. That beginning January 1, 2017, DEC, DEP and Piedmont shall fund the Duke Energy Foundation and Piedmont Natural Gas Foundation for four years from the close of the merger at annual levels of no less than \$9.65 million, \$6.375 million, and \$1.5 million, for community support and charitable contributions in the North Carolina service territories of DEC, DEP and Piedmont, respectively.
>
> 6. That in support of The Duke Energy Foundation's and Piedmont Natural Gas Foundation's North Carolina workforce development and low-income energy assistance in the North Carolina service territories of DEC, DEP, and Piedmont as may be agreed upon with the Public Staff, within twelve months of the close of the merger, DEC, DEP, and Piedmont shall contribute a total of \$7.5 million to The Duke Energy Foundation and Piedmont Natural Gas Foundation. The \$7.5 million shall be allocated among the North Carolina service territories of DEC, DEP, and Piedmont in proportion to the number of North Carolina jurisdictional customers served by each.

On December 15, 2016, the Applicants filed a Petition requesting that the Commission approve certain modifications to the above funding requirements. In summary, Applicants state that Duke Energy and Piedmont have determined that maintaining separate charitable foundations is duplicative, administratively inefficient, and unnecessarily expensive. As a result, the Applicants have decided to eliminate the Piedmont Natural Gas Foundation (Piedmont Foundation), and to fund the Duke Energy Foundation (Duke Foundation) to encompass the initiatives previously undertaken by the Piedmont Foundation, effective as of January 1, 2017.

Applicants further state that having the flexibility to provide direct support from DEC, DEP, and Piedmont for charitable and community support programs, in addition to funding some of the Duke Foundation's initiatives as provided for in the Merger Order, will facilitate and enhance the Applicants' compliance with their funding commitments. Applicants state that they intend for the majority of the $17.5 million in charitable contributions required by Ordering Paragraph No. 5 of the Merger Order to be made directly to the Duke Foundation, and that this funding structure is consistent with the historic practices used to honor similar commitments approved in the Duke Energy/Progress Energy, Inc. merger in Docket Nos. E-2, Sub 998 and E-7, Sub 986 (Duke/Progress Merger Order).

Moreover, Applicants state that to expedite the funding of the $7.5 million commitment for North Carolina workforce development and low-income energy assistance, as set forth in Ordering Paragraph No. 6 of the Merger Order, they request that DEC, DEP, and Piedmont be allowed to pay these charitable contributions directly to the organizations agreed upon by the Public Staff and the Applicants, and that this funding structure is consistent with the historic practices used to honor similar commitments approved in the Duke/Progress Merger Order.

In addition, Applicants state that they will track their compliance with the above commitments and provide reporting as the Public Staff and Commission deem appropriate. Finally, Applicants note that they have discussed this matter with the Public Staff and that the Public Staff has no objections to their request.

On January 5, 2017, the Commission issued an Order Requesting Comments on the Applicants' proposed modifications to the workforce development and community support funding process. The Commission's Order set February 1, 2017, as the date for initial comments and February 15, 2017, as the date for reply comments.

No party filed initial or reply comments.

Based on the Applicants' Petition and the record, the Commission concludes that there is good cause to approve the Applicants' proposed modifications to the workforce development and community support funding process.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the __17th__ day of February, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-2, SUB 1095
DOCKET NO. E-7, SUB 1100
DOCKET NO. G-9, SUB 682

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	ORDER APPROVING PLAN FOR
Application of Duke Energy Corporation and	)	DISTRIBUTION OF WORKFORCE
Piedmont Natural Gas, Inc., to Engage in a	)	DEVELOPMENT AND LOW-
Business Combination Transaction and	)	INCOME CUSTOMER ENERGY
Address Regulatory Conditions and Code of	)	ASSISTANCE FUNDS
Conduct	)	

BY THE COMMISSION: On September 29, 2016, the Commission issued an Order Approving Merger Subject to Regulatory Conditions and Code of Conduct (Merger Order) in the above-captioned dockets approving the merger of Duke Energy Corporation (Duke Energy) and Piedmont Natural Gas Company, Inc. (Piedmont). The Merger Order includes numerous conditions to be met by Duke Energy, Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), and Piedmont (collectively, Applicants). In particular, Ordering Paragraph No. 6 provides:

> 6. That in support of The Duke Energy Foundation's and Piedmont Natural Gas Foundation's North Carolina workforce development and low-income energy assistance in the North Carolina service territories of DEC, DEP, and Piedmont as may be agreed upon with the Public Staff, within twelve months of the close of the merger, DEC, DEP, and Piedmont shall contribute a total of $7.5 million to The Duke Energy Foundation and Piedmont Natural Gas Foundation. The $7.5 million shall be allocated among the North Carolina service territories of DEC, DEP, and Piedmont in proportion to the number of North Carolina jurisdictional customers served by each.

On December 15, 2016, the Applicants filed a Petition requesting that the Commission approve certain modifications to the above funding requirements. In summary, Applicants stated that Duke Energy and Piedmont had determined that maintaining separate charitable foundations was duplicative, administratively inefficient, and unnecessarily expensive. As a result, the Applicants had decided to eliminate the Piedmont Natural Gas Foundation (Piedmont Foundation), and to fund the Duke Energy Foundation (Duke Foundation) to encompass the initiatives previously undertaken by the Piedmont Foundation, effective as of January 1, 2017. In addition, the Applicants' Petition described other steps that had been agreed upon with the Public Staff for expediting the workforce development and community support funding required of the Applicants by the Merger Order.

On January 5, 2017, the Commission issued an Order Requesting Comments on the Applicants' proposed modifications to the workforce development and community support funding process. No party filed initial or reply comments.

On February 17, 2017, the Commission issued an Order approving the Applicants' proposed modifications to the workforce development and community support funding process.

On March 22, 2017, the Applicants filed a proposed plan for the distribution of the workforce development and low-income energy assistance funds required by Ordering Paragraph No. 6. In summary, the Applicants' propose to allocate $5 million to Duke Energy's Community College Grant Program for workforce development, and $2.5 million to the Duke Energy Helping Home Fund for low-income energy assistance. The Applicants used customer data on a county-by-county basis to allocate the funds among the North Carolina service territories of DEC, DEP and Piedmont, as required by the Merger Order. The following is a breakdown of how the Applicants propose that the funds be distributed by program and region.

Community College Grant Program	35% to DEP (including PNG regions)	$1,750,000
	65% to DEC (including PNG regions)	$3,250,000
	TOTAL for Community College Grant Program	**$5,000,000**
Low Income Energy Assistance	35% to DEP (including PNG regions)	$ 875,000
	65% to DEC (including PNG regions)	$1,625,000
	TOTAL for Low Income Energy Assistance	**$2,500,000**

With regard to workforce development, Applicants state that they met with a variety of stakeholders: North Carolina Community College System, North Carolina Department of Commerce, North Carolina Community Foundation, Foundation for the Carolinas, Duke Energy Foundation, Duke Energy Economic Development and manufacturing experts. Applicants state that the consensus was that the major opportunity for workforce development is the creation of robust apprenticeship and pre-apprenticeship programs. Further, Applicants state that the Duke Energy Community College Grant Program (Grant Program) will focus on creating a talent pipeline, for existing and potential industry, by funding adult apprenticeship and pre-apprenticeship programs for incumbent and new workers. A three-person committee representing Duke Energy, North Carolina Community Colleges and the North Carolina Department of Commerce will award grants twice a year. The Grant Program will provide four-year grants to community colleges, with a maximum of $200,000 per grant, including up to $75,000 allotted for equipment. Data from the North Carolina Works Apprenticeship Program will be used to evaluate the apprenticeship programs.

With regard to low-income energy assistance, Applicants note that as a result of general rate cases in 2013, Duke Energy created the Duke Energy Helping Home Fund (Assistance Fund) to leverage funding and resources from federal, state and local programs involved with energy improvements for low-income customers. Applicants state that this approach maximized program benefits for Duke Energy customers and ensured that designated dollars were spent directly for the benefit of low-income households. In addition, Applicants state that by improving the energy efficiency of low-income households, the Assistance Fund increased the affected customers' level of disposable income.

Applicants propose the same approach for distribution of the Merger Order funds from the Assistance Fund, targeting customers at or below 200% of the Federal Poverty Guidelines. The Assistance Fund will supplement Duke Energy's weatherization program by providing monies up front for health and safety repairs, limited to $3,000 per home unless approved in writing by Duke Energy. Applicants state that the health and safety repairs can include structural repairs, electrical, plumbing, mold/lead remediation, and other measures that (1) are not currently covered by weatherization agencies; (2) cost more than the allowable expense for weatherization; or (3) benefit homes no longer eligible for weatherization services. The Assistance Fund will continue to provide new Energy Star appliances, including refrigerators, washers, dryers, room air conditioners and dehumidifiers, to eligible customers, with the total appliance cost limited to $2,000 per home unless approved in writing by Duke Energy. Repairs and/or tune up on HVAC systems will be limited to $800 per home unless approved in writing by Duke Energy.

Applicants state that they discussed their proposal with the Public Staff and the Public Staff agrees with the approach.

Based on the Applicants' proposed plan for the distribution of the workforce development and low-income energy assistance funds and the record, the Commission finds good cause to approve the Applicants' plan.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of March, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. E-22, SUB 544

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Virginia Electric and Power Dominion, d/b/a Dominion, for Approval of Renewable Energy and Energy Efficiency Portfolio Standard Cost Rider Pursuant to G.S. 62-133.8 and Commission Rule R8-67	)	ORDER APPROVING REPS AND REPS EMF RIDERS AND 2016 REPS COMPLIANCE

BEFORE: Commissioner Daniel G. Clodfelter, Presiding; Chairman Edward S. Finley, Jr.; Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson, and Lyons Gray

HEARD: Monday, November 6, 2017, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

APPEARANCES:

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

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

Horace P. Payne, Jr., Dominion Resources Services, Inc., 120 Tredegar Street, Riverside-2, Richmond, Virginia 23219

For the Using and Consuming Public:

Tim R. Dodge and Robert B. Josey, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On August 23, 2017, Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (Dominion), 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 G.S. 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 G.S. 62-133.8(b), (d), (e), and (f), and to true-up any under-recovery or over-recovery of compliance costs. Thus, Dominion's annual REPS Rider has two components: (1) a forward-looking component to recover DEP's projected REPS compliance costs for calendar year 2018 (proposed by Dominion as Rider RP), and (2) a REPS Experience Modification Factor (EMF) to true-up any over- or under-recovery of REPS compliance costs under the previous REPS Rider from July 1, 2016 to June 30, 2017 (proposed by Dominion as Rider RPE). Dominion's application was accompanied by the testimony and exhibits of George E. Hitch, Senior Market Originator; Alan J. Moore, Regulatory Analyst III; and James D. Merritt, Regulatory Analyst II. In its application and pre-filed testimony, Dominion sought approval of the proposed REPS rider and REPS EMF rider, which incorporated the Dominion's proposed adjustments in its NC retail rates. In addition, Dominion requests that the Commission approve its 2017 REPS Compliance Report for calendar year 2016 REPS compliance, which was sponsored as an exhibit by Dominion witness George E. Hitch.

On August 30, 2017, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice, setting this matter for hearing; establishing deadlines for the submission of intervention petitions, intervenor testimony, and DEP's rebuttal testimony; requiring the provision of appropriate public notice; and mandating compliance with certain discovery guidelines. Dominion subsequently published notice in newspapers of general circulation, as required by that Order, and filed proof of publication on October 25, 2017.

The intervention and participation of the Public Staff in this docket are recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). No persons sought to intervene in this proceeding.

On October 23, 2017, the Public Staff filed the affidavits of Sonja R. Johnson, an accountant in the Public Staff Accounting Division, and Evan D. Lawrence, an engineer in the Public Staff Electric Division.

On October 30, 2017, Dominion filed a letter in lieu of filing rebuttal testimony indicating that, based on the Public Staff's affidavits recommending that the Commission approve Dominion's proposed riders and there being no further recommendations, Dominion will not be filing rebuttal testimony in this proceeding.

On November 1, 2017, Dominion and the Public Staff filed a joint motion in which they notified the Commission that they were not in disagreement on any issue and had agreed to waive cross-examination of each other's witnesses. In addition, Dominion and the Public Staff requested that all witnesses be excused from attending the hearing. The Commission granted this request by Order issued on November 3, 2017.

This matter came on for hearing on November 6, 2017. No public witnesses appeared at the hearing. Dominion presented the testimony and exhibits of witnesses Hitch, Moore, and Merritt, and the Public Staff presented the affidavits of witnesses Johnson and Lawrence. The testimony, exhibits, and affidavits were accepted into evidence.

Based upon the foregoing, including the testimony, exhibits, and affidavits received into evidence, 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. Dominion 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. Dominion is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public for compensation in North Carolina. Dominion is also an electric power supplier as defined in G.S. 62-133.8(a)(3). Dominion is lawfully before the Commission based upon its Application filed pursuant to G.S. 62-133.8 and Commission Rule R8-67.

2. The test period and billing period for this proceeding are, respectively, the period from July 1, 2016 through June 30, 2017 (Test Period), and January 1, 2018 through December 31, 2018 (Billing Period).

3. Pursuant to G.S. 62-133.8(h), an electric power supplier is authorized to recover the "incremental costs" of compliance with the REPS requirements through an annual REPS rider. The "incremental costs," as defined in G.S. 62-133.8(h)(1), include the reasonable and prudent costs incurred by an electric power supplier to comply with REPS "that are in excess of the electric supplier's avoided costs." The term "avoided costs" includes both avoided energy costs and avoided capacity costs. Pursuant to Commission Rule R8-67(e)(2), the total costs reasonably and prudently incurred during the Test Period to purchase unbundled renewable energy certificates (RECs) constitute incremental costs. The projected costs to purchase such RECs during the Billing Period constitute forecasted incremental costs.

4. For calendar year 2016, Dominion is required to meet at least 6% of its previous year's NC retail electric sales by a combination of renewable energy and energy consumption reductions due to the implementation of energy efficiency (EE) measures (General REPS Requirement). Dominion may meet the General REPS Requirement by any one or more of the compliance options listed in G.S. 62-133.8(b)(2). Pursuant to G.S. 62-133.8(b)(2)(e), Dominion may use 100% out-of-state RECs to achieve REPS compliance.

5. Also in 2016, Dominion is required to acquire solar energy, or RECs for solar energy, by the end of 2016 in an amount equal to at least 0.14% of the previous year's NC retail sales (Solar Set-Aside Requirement). These solar energy sources can be a combination of new solar electric facilities and new metered solar thermal energy facilities.

6. Beginning in 2012, G.S. 62-133.8(e) and (f) require Dominion and the electric power 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, 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 North Carolina retail sales (respectively, the Swine Waste Set-Aside Requirement and the Poultry Waste Set-Aside Requirement). In its Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief, issued on October 17, 2016, in Docket No. E-100, Sub 113 (2016 Delay Order), the Commission delayed for one year the Swine Waste Set-Aside Requirement, directing that these requirements will commence in 2017. The 2016 Delay Order also modified the Poultry Waste Set-Aside

Requirement by maintaining the same level as the 2015 requirement (170,000 MWh) and delaying by one year the scheduled increases in these requirements.

7. Dominion has agreed to provide REPS compliance services, including the procurement of RECs, to the Town of Windsor pursuant to G.S. 62-133.8(c)(2)(e). The Town of Windsor's 2016 REPS compliance status is included in Dominion's 2017 compliance report.

8. Dominion's approach of managing its retail REPS compliance costs separately from the REPS compliance costs for its wholesale customer, the Town of Windsor, is reasonable.

9. Dominion has complied with the 2016 General REPS Requirement and the Solar Set-Aside Requirement for itself and the Town of Windsor. As modified by the 2016 Delay Order, Dominion has complied with the Poultry Waste Set-Aside Requirement for itself and the Town of Windsor, and the Swine Waste Set-Aside Requirements were delayed by one year.

10. Dominion's 2017 REPS compliance report, filed pursuant to Commission Rule R8-67(c), contains all the information required by Rule R8-67(c) and demonstrates that Dominion is in compliance with G.S. 62-133.8(b) for 2016.

11. The costs incurred by Dominion to fund research activities during the Test Period, including the micro-grid research project costs, are "incremental costs" recoverable pursuant to G.S. 62-133.8(h)(1)(b). These research costs are within the $1,000,000 annual limit. Dominion appropriately included in its 2017 REPS compliance report a final status report on the micro-grid research project, whose three-year demonstration period (2015-2017) ended this year.

12. Dominion appropriately calculated its avoided costs for the Test Period and Billing Period. For purposes of establishing the REPS EMF rider charge in this proceeding, Dominion's incremental costs for REPS compliance during the Test Period were $839,144, and these costs were reasonably and prudently incurred. During the Test Period, Dominion collected revenue totaling $369,848 through REPS rider charges, resulting in an under-recovery of $469,296, which is appropriately recovered through REPS EMF rider charges during the Billing Period. Dominion's projected incremental costs for REPS compliance for the Billing Period are $716,429, and these costs were reasonably and prudently calculated.

13. Dominion's total adjusted number of customer accounts is 120,449, including 102,840 in the residential class, 17,548 in the commercial class, and 61 in the industrial class.

14. The appropriate NC retail Billing Period expenses for use in this proceeding are $363,784 for the residential class, $344,644 for the commercial class, and $8,002 for the industrial class.

15. The appropriate NC retail Test Period expenses for use in this proceeding are $239,162 for the residential class, $224,893 for the commercial class, and $5,241 for the industrial class.

16. The appropriate monthly, per-account, amount of the forecasted REPS rider charges to be collected during the Billing Period through Dominion's Rider RP, including the

regulatory fee, are $0.30 for residential accounts, $1.64 for commercial accounts, and $10.95 for industrial accounts. The appropriate monthly, per-account, amount of the REPS EMF rider charges to be collected during the Billing Period through Dominion's Rider RPE, including the regulatory fee, are $0.19 for residential, $1.07 for commercial, and $7.17 for industrial. The combined monthly, per-account, REPS and REPS EMF charges to be collected during the Billing Period, including the regulatory fee, are $0.49 for residential accounts, $2.71 for commercial accounts, and $18.12 for industrial accounts. These combined REPS rider charges, on an annual basis, are within the annual cost caps established in G.S. 62-133.8(h)(4).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, jurisdictional, and procedural in nature and is uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2-6

The evidence for these findings of fact can be found in the testimony and exhibits of the testimony and exhibits of Dominion witness Hitch and the affidavit of Public Staff witness Lawrence. These findings of fact are essentially informational, jurisdictional, and procedural in nature and are uncontested.

Pursuant to G.S. 62-133.8(h)(4), the Commission is required to allow an electric power supplier to recover all of its incremental costs incurred to comply with G.S. 62-133.8 through an annual rider. "Incremental costs," as defined in G.S. 62-133.8(h)(1), means all reasonable and prudent costs incurred by an electric power supplier to comply with the REPS requirement that are in excess of the electric power supplier's avoided costs, other than those costs recovered pursuant to 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."

Commission Rule R8-67(e)(1) provides that the Commission shall schedule an annual public hearing to review an electric utility's REPS compliance costs. Subdivision (e)(3) of Rule R8-67 further provides that the test period for each utility shall be the same as the test period for purposes of Commission Rule R8-55. Pursuant to Rule R8-55, Dominion's test period is the twelve months ending June 30 of each year. Therefore, Dominion proposed a test period for its REPS cost recovery proceeding of the twelve months ending June 30, 2017.

Commission Rule R8-67(e)(4) further provides that the REPS and REPS EMF riders shall be in effect for a fixed period, which "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." Commission Rule R8-67(e)(5) provides that "[t]he 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." In its current fuel charge adjustment proceeding, in Docket No. E-22, Sub 546, and in this proceeding, DEP proposed that its rate adjustments take effect on January 1, 2018, and remain in effect for a twelve month period.

Dominion's proposed test period and billing period were not challenged by the Public Staff. Based upon the foregoing, and the entire record in this proceeding, the Commission finds that the test period appropriate for use in this proceeding is the twelve months ending June 30, 2017, and the appropriate billing period is the twelve months ending December 31, 2018.

Pursuant to G.S. 62-133.8(b)(1) each electric public utility in the state is required to produce a certain percentage of its NC retail electric sales from various renewable energy or EE resources. An electric public utility may meet these requirements from any one or more of the following compliance options listed in G.S. 62-133.8(b)(2): (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 produced from in-State or out-of-state new renewable energy facilities; (f) using electric power that is supplied by a new renewable energy facility or saved due to the implementation of an EE 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 2015, an electric public utility in the state of North Carolina must meet a total REPS requirement equal to at least six percent of its previous year's NC retail electric sales by a combination of these measures.

Pursuant to G.S. 62-133.8(d) a certain percentage of the total electric power sold to retail electric customers in the State, or an equivalent amount of energy, shall be supplied by a combination of new solar electric facilities and new metered solar thermal energy facilities. The minimum percentage requirement for solar resources in 2016 is 0.14%.

Pursuant to G.S. 62-133.8(e) and (f) Dominion and other electric suppliers of North Carolina, in the aggregate, shall procure a certain portion of their renewable energy requirements from electricity generated from swine and poultry waste. The General Assembly established an initial aggregate 0.07% swine waste resources requirement in 2012, increasing thereafter. Subsection 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 issued on March 31, 2010, in Docket No. E-100, Sub 113, Dominion's share of the statewide aggregate Swine and Poultry Waste Set-Aside requirements is to be based upon the ratio of its NC retail kilowatt-hour (kWh) sales for the previous year divided by the previous year's total North Carolina retail kWh sales. 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.

Pursuant to G.S. 62-133.8(i)(2), the Commission shall include in its rules implementing the REPS statute a procedure to modify or delay the provisions of G.S. 62-133.8(b), (c), (d), (e), and (f), if the Commission determines it is in the public interest to do so, upon a showing that the electric power supplier made a reasonable effort to meet the REPS requirements. The Commission adopted Commission Rule R8-67(c)(5) to implement this procedure. On October 17, 2016, in Docket No. E-100, Sub 113, the Commission issued an Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief, further delaying for one year the commencement of the Swine Waste Set-Aside Requirements, modifying the Poultry Waste Set-Aside Requirements to remain at the same level as the 2015 requirement (an aggregate of 170,000 megawatt-hours (MWh) of electricity generated via poultry waste divided amongst the electric power suppliers), and delaying by one year the scheduled increases in these requirements. On October 17, 2016, the Commission issued the 2016 Delay Order, again delaying the Swine Waste Set-Aside Requirements by one year and modifying the Poultry Waste Set-Aside Requirements to remain at the same 170,000 MWh level and delaying by one year the scheduled increases in these requirements. Most recently, 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 has established that the aggregate statewide poultry waste resource requirement for the State's electric power suppliers, including Dominion, is 170,000 MWh for 2016 and 2017, and delayed the initial swine waste requirement until 2018.

Pursuant to G.S. 62-133.8(c), the Town of Windsor, and other municipal electric service providers, are required to meet similar obligations under the REPS.

Pursuant to G.S. 62-133.8(b)(2)(e), 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, G.S. 62-133.8(b)(2)(e) 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 Dominion for purposes of both its general REPS obligation and individual set-aside requirements pursuant to G.S. 62-133.8(d)-(f). Dominion may, therefore, achieve 100% of its REPS compliance using RECs generated by out-of-state new renewable energy facilities.

Pursuant to G.S. 62-133.8(b)(2)(c), an electric power supplier may use energy efficiency certificates (EECs) to meet no more than 25% of its total requirement. However, this limitation on the use of EECs to meet the total requirement does not apply to municipal electric power suppliers such as the Town of Windsor.

Dominion witness Hitch sponsored Dominion's 2017 REPS compliance report for compliance year 2016 as an exhibit to his testimony. In its 2017 REPS compliance report

Dominions states that the report contains the information required by Commission Rule R8-67(c) for itself and the Town of Windsor.

Public Staff witness Lawrence presented the Public Staff's analysis and recommendations with respect to Dominion's 2017 REPS compliance report. Based upon his review, witness Lawrence recommends that the Commission approve Dominion's 2017 REPS compliance report.

Based upon the foregoing and the entire record in this proceeding, the Commission finds that Dominion's proposed Test Period and Billing Period are appropriate, and that Dominion appropriately described its REPS requirements and those of the Town of Windsor as part of the information required to be included in Dominion's 2017 REPS compliance report, as is more particularly described in these findings of fact.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is found in the testimony and exhibits of Dominion witness Hitch, and is uncontroverted. Dominion witness Hitch testified that Dominion purchases RECs for use by the Town of Windsor, its wholesale customer, to meet its REPS obligations. However, 75% of the Town of Windsor's RECs must be obtained from in-state sources, whereas Dominion, pursuant to 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, Dominion has directly assigned to the Town of Windsor the costs of RECs used for its REPS compliance, and has excluded them from the REPS costs Dominion is seeking to recover in this proceeding. Similarly, Dominion witness Hitch testified that other incremental REPS compliance costs reasonably attributable to the Town of Windsor are excluded from the costs that Dominion is seeking to recover. The Public Staff made no objection to the manner in which Dominion separates its own REPS compliance costs from those incurred on behalf of the Town of Windsor. The Commission finds that Dominion's approach of managing its retail REPS costs separately from the REPS costs for the Town of Windsor is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8-10

The evidence supporting this finding of fact is found in the testimony and exhibits of Dominion witness Hitch, including Dominion's 2017 REPS compliance report, and in the affidavit of Public Staff witness Lawrence, and is uncontroverted.

Dominion witness Hitch testified that his job responsibilities include developing Dominion's annual REPS compliance report required by Commission Rule R-867(c). Dominion's 2017 REPS compliance report, which was sponsored as an exhibit by witness Hitch, states that the report includes the information required by Commission Rule R8-67(c) for Dominion and the Town of Windsor and demonstrates Dominion's compliance with the REPS requirements for compliance year 2016. In his affidavit, Public Staff witness Lawrence states that he reviewed Dominion's 2017 REPS compliance report and that, based upon his review, he recommends that it be approved.

Dominion's 2017 REPS compliance report states that Dominion's 2015 retail electric sales were 4,377,561 MWh and the Town of Windsor's were 50,704 MWh. Dominion's 6% 2016 total

REPS obligation amounted to 262,654 RECs, including 250,897 general obligation RECs, 6,129 solar RECs (0.14% of 4,377,561), 5,628 poultry waste RECs, and 15,105 EECs from its portfolio of in-state EE programs approved pursuant to G.S. 62-133.9. The Town of Windsor's 6% 2016 total REPS obligation amounted to 3,043 RECs, including 2,908 general RECs, 71 solar RECs (0.14% of 50,704) and 65 poultry waste RECs. The Town of Windsor did not use any EECs for compliance. Public Staff witness Lawrence states that these numbers of RECs met the REPS requirements that 6% of 2015 retail sales must be matched with an equivalent number of RECs in 2016, including 0.14% of 2015 retail sales that must be matched with an equivalent number of RECs derived from solar energy. Witness Lawrence confirmed that Dominion had placed the requisite numbers of RECs in its own and in the Town of Windsor's NC-RETS compliance sub-accounts. The records of NC-RETS confirm that Dominion complied with the provisions of G.S. 62-133.8(b)(2)(e) and (c)(2)(d) by placing the requisite number of RECs in the appropriate sub-account for the 2016 compliance year.

Public Staff witness Lawrence states that Dominion indicated in response to Public Staff data requests in previous years, that it determines the service life of an energy efficiency measure for REPS compliance purposes based on the measure lives Dominion uses when filing for approval of a DSM program. As an example, Dominion noted its most recent Application for Approval of the Small Business Improvement Program, as filed on July 29, 2016, in Docket No. E-22, Sub 538, which presents measure lives of 14 years.

The Public Staff does not dispute that Dominion and the Town of Windsor complied with their 2016 REPS requirements.

Based on the foregoing and the entire record in this proceeding, the Commission finds that Dominion and its wholesale customer, the Town of Windsor, for which Dominion is providing REPS compliance services, have complied with the General REPS Requirement, the Solar Set-Aside Requirement, and the Poultry Waste Set-Aside Requirement, as modified by the 2016 Delay Order. Dominion and the Town of Windsor, like other electric power suppliers have been relieved of the requirement to comply with the Swine Waste Set-Aside Requirement pursuant to the 2016 Delay Order. The Commission further finds that Dominion's 2017 REPS compliance report contains all the information required by Commission Rule R8-67(c) for Dominion and the Town of Windsor, sufficient to demonstrate Dominion and Windsor's compliance with the REPS requirements. Therefore, the Commission concludes that Dominion's 2017 REPS compliance report for compliance year 2016 should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding of fact is found in the testimony and exhibits of Dominion witnesses Hitch and Moore and the affidavits of Public Staff witnesses Lawrence and Johnson, and is uncontroverted.

Pursuant to 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) fund 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.

Dominion witnesses Hitch and Moore described the status of Dominion's micro-grid project, which the Commission approved in Dominion's 2013 REPS rider proceeding, Docket No. E-22, Sub 503, as a research project qualifying for REPS rider cost recovery pursuant to G.S. 62-133.8(h)(1). Dominion's micro-grid project was constructed at Dominion'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.

Dominion agreed to file annual reports on the micro-grid during its three-year demonstration period (2015-2017), and the last of these reports was included in Dominion's 2017 REPS compliance report as Appendix C. As originally constructed, the micro-grid integrated a behind-the-meter on-site diesel generator; a utility feed; one five-kilowatt (kW) horizontal-axis and three vertical- axis wind turbines (3-kW, 4-kW and 1.2-kW); a lithium ion battery with a 75-kWh storage capacity and 25-kW discharge rate; a 6-kW ground-mounted solar array; protective relays, inverters, proprietary control software, metering, and circuit breakers; and round-the-clock system monitoring. Dominion reported that the original 5-kW turbine failed to perform in a satisfactory manner, and it has been replaced by the vendor, at no cost to Dominion, with a 6-kW turbine from a different manufacturer. On July 27, 2015, Dominion integrated into the micro-grid two 1.5-kW fuel cells sized for residential and small commercial customer applications. The confidential exhibits of Dominion witness Moore set forth the costs of the micro-grid project incurred during the Test Period and projected for the Billing Period.

In his affidavit, Public Staff witness Lawrence states that the Public Staff reviewed Dominion's micro-grid research costs as part of its investigation into Dominion's Application. He further states that the Public Staff does not take issue with Dominion's testimony concerning the nature and costs of its micro-grid research activity, or with the reasonableness of the micro-grid costs included for recovery.

Based upon the foregoing and the entire record in this proceeding, the Commission finds that the research activities proposed by Dominion to be funded during the rate period are eligible research costs recoverable under G.S. 62-133.8(h)(1)(b), and that such research costs are within the annual $1,000,000 limit. The Commission further finds that Dominion has fulfilled its commitment to provide the Commission status reports on the micro-grid research project. Therefore, the Commission concludes that Dominion should not be required to make additional reports regarding its micro-grid project.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-16

The evidence supporting these findings of fact is found in the testimony and exhibits of Dominion witnesses Hitch, Moore, and Merritt and the affidavits of Public Staff witnesses Lawrence and Johnson.

Dominion witness Hitch testified that Dominion has not made any purchases of renewable energy as part of its REPS compliance, electing to meet its REPS obligations entirely through the purchase of RECs. For that reason, he testified, 100% of Dominion's REC costs are "incremental costs" recoverable through the REPS rider. He further testified that, although Dominion includes its avoided cost rates in its 2017 REPS compliance report, these rates were not required to determine the incremental costs of Dominion's 2016 REPS compliance. In addition, he testified that while Dominion has identified certain direct and non-labor costs associated with REPS compliance, Dominion is not seeking to recover these costs in this proceeding as it evaluates how to appropriately track and allocate these costs. Witness Hitch also noted that Dominion is seeking recovery of costs of the micro-grid project, as discussed in the previous section. Witness Hitch concluded his testimony by stating that Dominion's costs incurred to meet its REPS compliance obligations were reasonably and prudently incurred. In its 2017 compliance report, which witness Hitch sponsored as an exhibit to his testimony, Dominion states that its total customer accounts for each customer class were as follows: 102,258 residential customers, 17,911 commercial customers, and 52 industrial customers.

Dominion witness Moore testified to the details of Dominion's requested cost-recovery included in its application. Witness Moore sponsored exhibits which set out in detail Dominion's incremental REPS compliance costs for the Test Period and projected costs for the Billing Period. Witness Moore testified that Dominion's total Test Period revenues were $369,848, resulting in an under-recovery of $469,296. Dominion seeks to recover this amount through the REPS EMF Rider (Rider RPE). As reflected in witness Moore's exhibit No. JDM-1, Schedule 2, the under-recovery attributed to each customer class is as follows: $239,162 for residential, $224,893 for commercial, and $5,241 for industrial. Witness Moore further testified that Dominion seeks to recover $716,429 in incremental costs for REPS compliance costs projected to be incurred during the Billing Period through the REPS rider charges (Rider RP). These costs are detailed in witness Moore's exhibit No. JDM-1, Schedule 4, and are allocated by customer class as follows: $363,784 for the residential class, $344,644 for the commercial class, and $8,002 for the industrial class.

Dominion witness Merritt testified to the methodology Dominion used to develop its proposed per-account, monthly REPS charges. Witness Merritt testified that Dominion used the same approach that the Commission has approved in its previous REPS rider proceedings for determining the total number of customer accounts in each class and for allocating REPS compliance costs to each class. Witness Merritt acknowledged the recent amendment to G.S. 62-133.8(h)(4), that reduced the annual limit on the REPS charge applicable to residential customers from $34 to $27. Witness Merritt testified that, because of the July 1, 2017 effective date, this change does not impact Dominion's REPS EMF rider charges, but will be used in developing REPS rider charges. Witness Merritt then testified that, in calculating the REPS EMF charges the total under-recovery experienced during the Test Period of $469,296 was divided by 12 to develop a per-month amount. That amount was then adjusted to account for the regulatory fee and to calculate the monthly, per-account REPS EMF charge for each customer class. This calculation is reflected in witness Merritt's schedule 3, which he sponsored as an exhibit to his testimony. Witness Merritt then testified that the calculation of monthly, per-account REPS charges was completed in a similar manner based on the incremental costs projected to be incurred during the Billing Period. This calculation is detailed in witness Merritt's schedule 4, which he sponsored as an exhibit to his testimony. Witness Merritt further testified that based on these calculations, Dominion has proposed combined, monthly, per-account REPS EMF rider and REPS rider charges are as follows: $0.49 for residential customers, $2.71 for commercial customers, and $18.12 for industrial customers. As compared to Dominion's current REPS rider charges this will result in decreases in these charges as follows: $0.39 for residential customers, $1.16 for commercial customers, and $7.70 for industrial customers. These comparisons are included in witness Merritt's schedule 7, which he sponsored as an exhibit to his testimony. Finally, witness Merritt testified that these proposed REPS rider charges do not exceed the annual limits set out in G.S. 62-133.8(h)(4), as reflected in witness Merritt's schedule 6.

Public Staff witnesses Lawrence and Johnson described the Public Staff's review of Dominion's REPS costs and, based upon their review, recommended that the Commission approve Dominion's proposed Rider RP and RPE charges.

Based upon the foregoing and the entire record herein, the Commission finds that Dominion appropriately calculated its incremental costs for REPS compliance for the Test Period and that these costs were reasonably and prudently incurred. The Commission further finds that Dominion appropriately forecasted its incremental costs for REPS compliance Billing Period. The Commission further finds that, consistent with the methodology approved by the Commission in past REPS rider proceedings, Dominion has appropriately adjusted its number of customer accounts, allocated its incremental costs of REPS compliance to each customer class, and that the resulting proposed REPS and REPS EMF rider charges as detailed in Dominion's application are appropriate. Therefore, the Commission concludes that Dominion should be allowed to collect the following combined, monthly per-account REPS and REPS EMF charges, including the regulatory fee, for each of the following customer classes: $0.49 for residential accounts, $2.71 for commercial accounts, and $18.12 for industrial accounts. These combined REPS rider charges, on an annual basis, are within the annual limits provided in G.S. 62-133.8(h)(4).

IT IS, THEREFORE, ORDERED as follows:

1. That Dominion shall establish REPS rider charges through its schedule Rider RP as described herein, in the amounts approved herein, and that these rider charges shall remain in effect for a 12-month period beginning January 1, 2018, and expiring December 31, 2018;

2. That Dominion shall establish REPS EMF rider charges through its schedule Rider RPE as described herein, in the amounts approved herein, and that these rider charges shall remain in effect for a 12-month period beginning January 1, 2018, and expiring December 31, 2018;

3. That Dominion 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 545 and 546, and Dominion 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;

4. That Dominion shall file appropriate rate schedules and riders with the Commission to implement the provisions of this Order as soon as practicable;

5. That Dominion's 2017 REPS compliance report, for calendar year 2016, is hereby approved, and the RECs and EECs in Dominion and the Town of Windsor's 2016 compliance sub-accounts in NC-RETS shall be retired; and

6. That Dominion has fulfilled its commitment to provide the Commission a final status report on the micro-grid research project and no additional reporting related to the micro-grid research project shall be required in Dominion's future annual REPS compliance reports.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of December, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-7, SUB 1032

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC,	)	ORDER APPROVING
for Approval of New Cost Recovery	)	REVIEW OF COST
Mechanism and Portfolio of Demand-Side	)	RECOVERY MECHANISM
Management and Energy Efficiency Programs	)	

BY THE COMMISSION: On October 29, 2013, the Commission issued an Order Approving DSM/EE Programs and Stipulation of Settlement in the above-captioned docket. The Order, among other things, approved the Cost Recovery and Incentive Mechanism for Demand-Side Management and Energy Efficiency Programs (Mechanism) proposed by Duke Energy Carolinas, LLC, (DEC) and agreed to by the Public Staff – North Carolina Utilities Commission (Public Staff), North Carolina Sustainable Energy Association, Environmental Defense Fund, Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, Sierra Club and Natural Resources Defense Council (Stipulating Parties). In addition, in Ordering Paragraph No. 11 the Commission stated that it would initiate a formal review of DEC's Mechanism not later than July 1, 2017, unless requested to do so earlier by DEC, the Public Staff or another interested party.

On July 18, 2017, Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, Sierra Club and Natural Resources Defense Council filed a letter stating that they did not believe that a review of DEC's Mechanism was necessary at this time.

On July 19, 2017, the Commission issued an Order Requesting Comments regarding recommended changes, if any, to DEC's Mechanism.

On August 18, 2017, the Stipulating Parties, and North Carolina Waste Awareness and Reduction Network, filed a letter stating that they do not propose any modifications to DEC's Mechanism, other than several revisions that were proposed by DEC and the Public Staff in Docket No. E-7, Sub 1130, DEC's annual DSM/EE rider proceeding.

No additional comments or reply comments were filed in this docket.

On August 23, 2017, in Docket No. E-7, Sub 1130, the Commission issued an Order Approving DSM/EE Rider, Revising DSM/EE Mechanism, and Requiring Filing of Proposed Customer Notice (Sub 1130 Order). The Sub 1130 Order, among other things, approved the revisions to DEC's Mechanism recommended by DEC and the Public Staff, effective January 1, 2018.

After careful consideration of the parties' filings and the record, the Commission finds good cause to approve the continued implementation of DEC's Mechanism without any changes other than the changes approved in the Sub 1130 Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the ___18th___ day of September, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. E-7, SUB 1129

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC	)	ORDER APPROVING
Pursuant to G.S. 62-133.2 and Commission Rule	)	FUEL CHARGE
R8-55 Relating to Fuel and	)	ADJUSTMENT
Fuel-Related Charge Adjustments for Electric	)	
Utilities	)	

HEARD: Tuesday, June 6, 2017, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding, Commissioner Edward S. Finley, Jr., Commissioner Bryan E. Beatty, Commissioner Don M. Bailey, Commissioner James G. Patterson, Commissioner Jerry C. Dockham, and Commissioner Lyons Gray

APPEARANCES:

For Duke Energy Carolinas, LLC:

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For the Carolina Utility Customers Association, Inc.:

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

For the North Carolina Sustainable Energy Association:

Peter Ledford, General Counsel, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Margaret A. Force, North Carolina Department of Justice, Assistant Attorney General, Post Office Box 629, Raleigh, North Carolina 27602

Robert B. Josey, Staff Attorney, Dianna W. Downey, Staff Attorney, Public Staff - North Carolina Utilities Commission, 430 N. Salisbury Street, 4326 MSC, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On March 8, 2017, Duke Energy Carolinas, LLC (Duke Energy Carolinas, DEC, or the Company) filed an application pursuant to G.S. 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 McGee, Swati V. Daji, Joseph A. Miller, Jr., Scott L. Batson, and David C. Culp.

Petitions to intervene were filed by the North Carolina Sustainable Energy Association (NCSEA) on March 14, 2017, by the Carolina Industrial Group for Fair Utility Rates III (CIGFUR) on March 16, 2017, and by the Carolina Utility Customers Association, Inc. (CUCA) on April 4, 2017. The Commission granted NCSEA's petition to intervene on March 15, 2017, CIGFUR's petition to intervene on March 17, 2017, and CUCA's petition to intervene on April 6, 2017. The North Carolina Attorney General's Office (AG) filed its notice of intervention on April 5, 2017.

On March 21, 2017, 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 May 22, 2017, that rebuttal testimony should be filed on June 1, 2017, and that a hearing on this matter would be held on June 6, 2017.

The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On May 15, 2017, DEC filed the supplemental testimony, revised exhibits and work papers of Kimberly D. McGee, as well as the supplemental testimony of Joseph A. Miller, Jr. In addition, DEC requested that the Commission permit Brett Phipps to adopt the testimony and exhibits of Swati V. Daji.

On May 22, 2017, the Public Staff filed the affidavits of Darlene P. Peedin and Dustin Metz.

On May 30, 2017, DEC and the Public Staff filed a motion requesting that all witnesses be excused from appearance at the expert witness hearing. On June 1, 2017, the Commission granted the motion, excusing DEC witnesses McGee, Phipps, Miller, Batson, and Culp, and Public Staff witnesses Peedin and Metz from appearing at the expert witness hearing.

On June 1, 2017, DEC filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's procedural order.

The case came on for hearing as scheduled on June 6, 2017. The prefiled direct and supplemental testimony and exhibits of DEC's witnesses and the prefiled affidavits and exhibits of the Public Staff's witnesses were received into evidence. No public witnesses appeared at the hearing.

Based upon the Company's verified application, the testimony, affidavits, and exhibits received into evidence at the hearing, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Duke Energy Carolinas is a duly organized corporation existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the Commission as a public utility. Duke Energy Carolinas is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.2.

2. The test period for purposes of this proceeding is the 12 months ended December 31, 2016 (test period).

3. In its supplemental testimony including exhibits in this proceeding, DEC requested a total decrease of approximately $12.4 million to its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee. The fuel and fuel-related cost factors requested by DEC included Experience Modification Factor (EMF) riders to take into account fuel and fuel-related cost under-recoveries and over-recoveries experienced during the test period, with an overall over-recovery of approximately $44 million. Interest applicable to the over-recovery was approximately $6.8 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 Company's merger-related fuel savings for the test period as reported in Schedule 11 of the Company's Monthly Fuel Report are reasonable.

7. The test period per book system sales are 86,586,600 megawatt-hours (MWh). The test period per book system generation (net of auxiliary use and joint owner generation) and purchased power is 93,726,358 MWh and is categorized as follows:

Net Generation Type	MWh
Coal	25,606,752
Natural Gas, Oil and Biomass	11,627,401
Nuclear	45,212,554
Hydro – Conventional	1,598,144
Hydro Pumped Storage	(775,997)
Solar DG	13,694
Purchased Power – subject to economic dispatch or curtailment	8,284,199
Other Purchased Power	1,945,948
Catawba Interchange	213,663
Total Net Generation	93,726,358

8. The appropriate nuclear capacity factor for use in this proceeding is 95.21%.

9. The North Carolina retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 58,279,168 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	21,711,352
General Service/Lighting	23,656,186
Industrial	12,911,629
Total	58,279,168[1]

10. The projected billing period (September 2017-August 2018) sales for use in this proceeding are 87,859,562 MWh on a system basis and 57,501,839 MWh on a North Carolina retail basis. The projected billing period North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	21,207,368
General Service/Lighting	23,147,882
Industrial	13,146,589
Total	57,501,839

11. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 94,704,366 MWh and is categorized as follows:

Generation Type	MWh
Coal	26,905,526
Gas Combustion Turbine (CT) and Combined Cycle (CC)	14,543,056
Nuclear	45,412,149
Hydro	4,467,404
Net Pumped Storage Hydro	(3,511,385)
Solar Distributed Generation (DG)	145,579
Purchased Power	6,742,038
Total	94,704,366

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 coal fuel price is $28.09/MWh.
B. The gas CT and CC fuel price is $26.13/MWh.
C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $36,577,248.

[1] Rounding difference of 1.

D. The total nuclear fuel price (including Catawba Joint Owners generation) is \$6.54/MWh.

E. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared) is \$228,293,506.

F. System fuel expense recovered through intersystem sales is \$46,735,681.

13. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are \$1,087,140,814.

14. The Company's North Carolina retail jurisdictional fuel and fuel-related expense over-collection for purposes of the EMF was approximately \$44.0 million, consisting of an over-recovery for the Residential, General Service/Lighting, and Industrial classes of \$20.3 million, \$15.7 million and \$7.9 million respectively. The over-collection resulted in interest of approximately \$6.8 million, consisting of \$3.1 million, \$2.4 million, and \$1.2 million for the Residential, General Service/Lighting and Industrial classes, respectively.

15. The decrease in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-7, Sub 1104, should be allocated between 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 DEC's rate classes, excluding the regulatory fee, are as follows: 1.7828¢/kilowatt-hour (kWh) for the Residential class; 1.9163¢/kWh for the General Service/Lighting class; and 2.0207¢/kWh for the Industrial class.

17. The appropriate EMF decrements established in this proceeding, excluding the regulatory fee, are as follows: (0.0937)¢/kWh for the Residential class; (0.0662)¢/kWh for the General Service/Lighting class; and (0.0616)¢/kWh for the Industrial class.

18. The appropriate EMF interest decrements established in this proceeding, excluding the regulatory fee, are (0.0144)¢/kWh for the Residential class; (0.0102)¢/kWh for the General Service/Lighting class; and (0.0095)¢/kWh for the Industrial class.

19. 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: 1.6747¢/kWh for the Residential class; 1.8399¢/kWh for the General Service/Lighting class; and 1.9496¢/kWh for the Industrial class.

20. The base fuel and fuel-related cost factor as approved in Docket No. E-7, Sub 1026 of 2.3182¢/kWh will be adjusted by amounts equal to (0.5354)¢/kWh, (0.4019)¢/kWh, and (0.2975)¢/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 and EMF interest decrements totaling (0.1081)¢/kWh, (0.0764)¢/kWh, and (0.0711)¢/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

G.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 December 31st as the test period for DEC. The Company's filing in this proceeding was based on the 12 months ended December 31, 2016.

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.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is contained in the testimony of Company witnesses Batson and Miller.

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 Batson testified that the Company's seven nuclear units operated at a system average capacity factor of 96.38% during the test period. This capacity factor, as well as the Company's 2-year average capacity factor of 96.03%, exceeded the five-year industry weighted average capacity factor of 87.92% for the period 2011-2015 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report.

Witness Batson testified that for the 17th consecutive year, DEC's seven nuclear units achieved a system average capacity factor exceeding 90%, ending the year, which included four refueling outages, with an average of 96.38%. For continuous operating days, Catawba Unit 1 set a new annual generation and capacity factor record, achieving a capacity factor of 102.28% for the year. Catawba Unit 2 established a new breaker-to-breaker run of 523 days, and the station completed a 266 day dual-unit run; the best performance since 2006. During the spring of 2016, Oconee Unit 3 set a new station record for the shortest refueling outage only to be surpassed in the fall by the Oconee Unit 1 outage. Also of note, McGuire Unit 2 and the McGuire station set new annual generation records during 2016, producing 10.36 GWHs and 19.88 GWHs respectively.

There were four refueling and maintenance outages during the test period beginning with the spring 2016 refueling and maintenance outage on McGuire Unit 1. Along with refueling, major work efforts included replacement of the 1C reactor coolant pump motor and 1A emergency diesel generator voltage regulator along with the 1A chemical and volume control pump rotating element. In addition, this site implemented modifications to increase reliability of the service water system and refurbishments were completed for the four main steam isolation valves. DEC successfully completed 10,504 work order tasks within the outage.

Company witness Batson testified that Oconee Unit 3 also had a spring refueling and maintenance outage. In addition to refueling activities, major work included performing 100 percent steam generator Eddy Current testing and implementing post-Fukushima tie-ins on the safety injection and auxiliary feedwater lines. An upgrade for improved efficiency was completed for the condenser tube cleaning system and the site successfully completed a reactor building integrated leak rate test. During the outage, 10,078 work order tasks were completed.

Catawba Unit 2 began a maintenance and refueling outage in September 2016. In addition to refueling, major work included the 2B condensate booster pump motor replacement, 2C1 and 2C2 heater drain pump motor replacements, 2B reactor coolant pump motor replacement, and 2B2 component cooling pump motor replacement, control rod guide card inspections, and installation of a new 2B diesel generator governor with enhanced capabilities. Main condenser tube and low pressure turbine maintenance was also accomplished. The site implemented expanded steam generator plugging scope to increase service time between maintenance. During the outage, 9,677 work order tasks were completed.

Company witness Batson testified, that Oconee Unit 1 had the final refueling and maintenance outage in 2016. The unit was returned to service ahead of the scheduled allocation, replacing the station outage duration record just established with Unit 3 in the spring of 2016. In addition to refueling activities, major work completed included Eddy Current testing on all tubes in both steam generators, the replacement of the 1A2 feedwater heater, preventive maintenance on the 3C low pressure turbine, replacement of the Amertap condenser tube cleaning system, and replacement of switchyard power circuit breakers 20 and 21. The Company also completed modifications required to comply with the Nuclear Regulatory Commission's post-Fukushima orders. During the outage, 10,881 work order tasks were completed.

Company witness Miller testified concerning the performance of DEC's fossil/hydro assets. He stated that the primary objective of the Company's fossil/hydro generation department is to safely provide reliable and cost-effective electricity to DEC's customers, and that it achieves this objective by focusing on a number of key areas. Witness Miller further stated that environmental compliance is a "first principle" and that DEC achieves compliance 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 Miller 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 Miller presented the following chart, which shows operation results, as well as results from the most recently published NERC Generating Availability Brochure for the period 2011 through 2015, and is categorized by generator type:

Generator Type	Measure	Review Period	2011-2015	Nbr of Units
		DEC Operational Results	NERC Average	
Coal-Fired Test Period	EAF	77.6%	79.9%	791
	NCF	42.8%	60.1%	
	EFOR	7.2%	8.1%	
Coal-Fired Summer Peak	EAF	85.3%	n/a	n/a
Total CC Average	EAF	94.1%	84.6%	309
	NCF	85.0%	51.6%	
	EFOR	0.54%	5.8%	
Total CT Average	EAF	93.3%	87.0%	876
	SR	99.7%	97.8%	
Hydro	EAF	87.1%	81.9%	1,141

Company witness Miller testified that the NERC data reported for the coal-fired units represents an average of comparable units based on capacity rating along with the EAF for the peak summer period of June through August. He also testified that the Company's CC fleet responded to the test period summer and winter peaks with a very strong performance. DEC customers established an all-time energy usage demand during the test period in the month of July 2017. The CC fleet EAF during the month of January and February was 99.46%, and 99.17% during the months June, July, and August.

Witness Miller also testified that Marshall Unit 2 completed a major boiler overhaul, which included front and rear boiler waterwall replacement in the Spring 2016. Allen Unit 5 completed an outage to replace the low pressure turbine rotor. Cliffside Unit 6 completed an outage, which included the replacement of the FGD header in Spring 2016. Belews Creek Units 1 and 2 completed outages in Fall 2016. The Belews Creek Unit 1 outage involved boiler inspections and repairs and shielding on the horizontal reheater. The primary purpose of the Belews Creek Unit 2 outage was to install weld overlay on the side walls of the boiler, replace the SCR roof, and conduct feedwater heater maintenance.

Within the hydro fleet, major outages included Bad Creek Units 1-4 and Jocassee Unit 3 and Unit 4 for turbine and generator inspections.

Concerning significant planned outages occurring at the Company's fossil and hydroelectric facilities during the test period, Company witness Miller 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.

Based upon the evidence in the record, the Commission concludes that DEC managed its baseload plants prudently and efficiently so as to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's updated fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A in December 2014, and were in effect throughout the 12 months ending December 31, 2016. 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, Miller, and Culp.

Company witness McGee testified that DEC's fuel procurement strategies that mitigate volatility in supply costs are a key factor in DEC's ability to maintain lower fuel and fuel-related rates. Other key factors include DEC's diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; lower natural gas prices; the capacity factors of its nuclear fleet; the combination of DEP's and DEC's respective skills in procuring, transporting, managing and blending fuels and procuring reagents; the increased and broader purchasing ability of the combined Company; 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 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 $82.54 per ton, compared to $89.72 per ton in the prior test period, representing a decrease of approximately 8.0%. This includes an average transportation cost of $24.92 per ton in the test period, compared to $27.66 per ton in the prior test period, representing a decrease of approximately 10%. Witness Phipps further testified that the Company's average price of gas purchased for the test period was $3.34 per Million British Thermal Units (MMBtu), compared to $3.97 per MMBtu in the prior test period, representing a decrease of approximately 16%.

Witness Phipps stated that DEC's coal burn for the test period was 9.8 million tons which was the same consumption as the prior test period. The Company's natural gas burn for the test period was 89 MMBtu, compared to a gas burn of 79 MMBtu in the prior test period, representing an increase of approximately 12%. The primary contributing factors were changes in weather driven demand and commodity prices.

Witness Phipps stated that coal markets continue to be in a state of flux due to a number of factors, including: (1) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency (EPA) regulations for power plants; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices combined with installation of new combined cycle (CC) generation by utilities, especially in the Southeast, which has also lowered overall coal demand; (3) continued changes in global market demand for both steam and metallurgical coal; (4) uncertainty surrounding regulations for mining operations; and (5) the on-going financial viability of many of the Company's coal suppliers.

He also testified that with respect to natural gas, the nation's natural gas supply has grown significantly and producers continue to enhance production techniques, enhance efficiencies, and lower production costs. In the shorter term, natural gas prices are reflective of the dynamics between supply and demand factors, such as seasonal weather 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 10.2 million tons compared to 9.8 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, delivered natural gas prices versus the average delivered cost of coal, volatile power prices, and electric demand. Combining coal and transportation costs, DEC projects average delivered coal costs of approximately $73.23 per ton for the billing period compared to $82.54 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 107 MMBtu, which is an increase from the 89 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 new Lee combined cycle facility which is scheduled to be commercially available in late 2017. The current average forward Henry Hub price for the billing period is $3.20 per MMBtu, compared to $2.46 per MMBtu in the test period. Projected burn volumes will vary based on factors such as, but not limited to, changes in actual delivered fuel costs.

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 expects to address any spot and long-term coal requirements throughout this year with any potential competitively bid purchases, if made, taking into account projected coal burns, as well as coal inventory levels.

Witness 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.

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. The Company's current financial hedging activities cover a rolling 36-month time period with approximately 50% of forecasted burns targeted to be hedged for months 1 to 12, approximately 30% of forecasted burns targeted to be hedged for months 13 to 24, and approximately 15% of forecasted burns targeted to be hedged for months 25 to 36.

G.S. 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 Miller testified that the Company has installed pollution control equipment on coal-fired units, as well as new generation resources 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) that DEC currently operates for its coal fleet uses ammonia or, in the case of Marshall Unit 3, urea, which is converted to ammonia 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 and Dan River CC's, in which aqueous ammonia (19% solution of NH_3) is introduced for NO_x removal.

Company witness Miller 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 Culp 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 long-term contracts from diverse sources of supply, and monitoring deliveries against contract commitments. Witness Culp 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.

G.S. 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 in assessing power purchases and off-system sales opportunities, DEP and DEC consider the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at generating units, estimated forced outages at generating units based on historical trends, generating unit performance parameters, and expected market conditions, in order to determine the most economic and reliable means of serving their customers.

No party presented or elicited 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 direct 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. 6

The evidence supporting this finding of fact is contained in the testimony of Company witnesses Phipps and McGee.

Company witness Phipps testified that as of September 2016, Duke Energy Carolinas and Duke Energy Progress met the guaranteed merger savings target of $721.8 million established pursuant to both the merger agreement between the two companies and the merger agreement between Duke Energy Corporation and Piedmont Natural Gas Company, Inc. The combined merger savings through September totaled $723 million, of which DEC's North Carolina share was $296 million.

Company witness McGee testified that merger fuel-related savings automatically flow through to DEC's retail customers through the fuel and fuel-related costs component of customers' rates. She explained that actual merger fuel-related savings during the test period are included in the EMF portion of the proposed fuel and fuel-related cost factors. In addition, in the prospective component of the factors, the projected merger fuel-related savings related to procuring coal and reagents, lower transportation costs, lower gas capacity costs, and coal blending are reflected in the cost of fossil fuel. Projected joint dispatch savings, which result from using DEC's and Duke Energy Progress, LLC's (DEP) combined systems' lowest available generation to meet total customer demand, are also reflected in the cost of fossil fuel as well as the projected cost purchases and sales that include the purchases and sales between DEC and DEP.

Based on the evidence presented by DEC, and noting the absence of evidence presented to the contrary by any other party, the Commission finds and concludes that the Company's merger-related fuel savings for the test period are reasonable.

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 McGee.

According to the exhibits sponsored by Company witness McGee, the test period per book system sales were 86,586,600 MWh, and test period per book system generation and purchased power amounted to 93,726,358 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	25,606,752
Natural Gas, Oil and Biomass	11,627,401
Nuclear	45,212,554
Hydro – Conventional	1,598,144
Hydro Pumped Storage	(775,997)
Solar DG	13,694
Purchased Power – subject to economic dispatch or curtailment	8,284,199
Other Purchased Power	1,945,948
Catawba Interchange	213,663
Total Net Generation	93,726,358

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 86,586,600 MWh and system generation and purchased power of 93,726,358 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 Batson.

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 95.21% 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 2017-2018 billing period. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 87.92% for the period 2011-2015 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report.

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 95.21% nuclear capacity factor, and its associated generation of 59,880,686 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 McGee.

On her Exhibit 4, Company witness McGee set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 58,279,168 MWh, comprised of Residential class sales of 21,711,352 MWh, General Service/Lighting class sales of 23,656,186 MWh, and Industrial class sales of 12,911,629 MWh.

Witness McGee used projected billing period system sales, generation, and purchased power to calculate the proposed prospective component of the fuel and fuel-related cost rate. The projected system sales level used, as set forth on Revised McGee Exhibit 2, Schedule 1, is 87,859,562 MWh. The projected level of generation and purchased power used was 94,704,366 MWh (calculated using the 95.21% 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	26,905,526
Gas Combustion Turbine (CT) and Combined Cycle (CC)	14,543,056
Nuclear	45,412,149
Hydro	4,467,404
Net Pumped Storage Hydro	(3,511,385)
Solar Distributed Generation (DG)	145,579
Purchased Power	6,742,038
Total	94,704,366

As part of her Workpaper 7, Company witness McGee also presented an estimate of the projected billing period North Carolina retail Residential, General Service/Lighting, and Industrial MWh sales. The Company estimates billing period North Carolina retail MWh sales to be as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	21,207,368
General Service/Lighting	23,147,882
Industrial	13,146,589
Total	57,501,839

These class totals were used in 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. 12

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 $28.09/MWh.
B. The gas CT and CC fuel price is $26.13/MWh.
C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $36,577,248.
D. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.54/MWh.
E. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared) is $228,293,506.
F. System fuel expense recovered through intersystem sales is $46,735,681.

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 G.S. 62-133.2.

No other party presented evidence on the level of DEC's fuel and fuel-related prices and expenses.

Based upon the evidence in the record as to the appropriate fuel and fuel-related prices and expenses, the Commission concludes that the fuel and fuel-related prices recommended by Company witness McGee and accepted by the Public Staff for purposes of determining projected system fuel expense are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

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 G.S 62-133.2(a2), witness McGee testified that the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs, qualifying facility capacity costs, and renewable energy costs does not exceed two percent of DEC's total North Carolina jurisdictional gross revenues for 2016.

According to McGee Exhibit 2, Schedule 1, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $1,087,140,814. 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 $1,087,140,814 is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 14-19

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness McGee and the affidavits of Public Staff witnesses Metz and Peedin.

Company witness McGee presented DEC's original fuel and fuel-related expense over-collection and prospective fuel and fuel-related cost factors. Company witness McGee's supplemental testimony and Revised Exhibits set forth the projected fuel and fuel-related costs, the amount of over/(under) collection for purposes of the EMF, the method for allocating the increase in fuel and fuel-related costs, the composite fuel and fuel-related cost factors, and the EMFs along with exhibits and workpapers reflecting the following adjustments: (1) correction to the Company's customer growth adjustment, (2) removal of costs associated with coal ash related to the Riverbend Steam Station, which will be addressed in the general rate application to be filed by DEC later this year, and (3) updating the EMF decrement and EMF interest decrement to incorporate the fuel and fuel related cost recovery balance for January through March 2017, pursuant to Commission Rule R8-55(d)(3). Public Staff witness Metz recommended the approval of the prospective and EMF components and total fuel factors (excluding regulatory fee) set forth in Company witness McGee's supplemental testimony.

Public Staff witness Peedin testified that the EMF riders proposed by DEC are based on DEC's calculated and reported North Carolina retail fuel and fuel-related cost over-recoveries of $20.3 million, $15.7 million, and $7.9 million for the Residential, General Service/Lighting, and Industrial classes, respectively. Public Staff witness Peedin also testified that interest on the over-recovered fuel and fuel-related amount from the Residential, General Service/Lighting, and Industrial class amounted to $3.1 million, $2.4 million, and $1.2 million. She recommended that DEC's EMF riders for each customer class be based on these net fuel and fuel-related cost under-recovery and over-recovery amounts and on the Company's proposed normalized North Carolina retail sales of 21,711,352 MWh for the residential class, 23,656,186 MWh for the general service/lighting class, and 12,911,629 MWh for the industrial class, as proposed by the Company. She stated that these amounts produce EMF decrement riders for each North Carolina retail customer class as follows, excluding the regulatory fee (decrements shown in parentheses):

Residential	(0.0937) cents per kWh
General Service/Lighting	(0.0662) cents per kWh
Industrial	(0.0616) cents per kWh

She also recommended EMF interest decrements, excluding the regulatory fee, of (0.0144)¢/kWh for the Residential class; (0.0102)¢/kWh for the General Service/Lighting class; and (0.0095)¢/kWh for the Industrial class.

As a result of witness Peedin's recommendation, Public Staff witness Metz recommended the following EMF and EMF interest decrement billing factors:

N.C. Retail Customer Class	EMF Decrement (cents/kWh)	EMF Interest Decrement (cents/kWh)
Residential	(0.0937)	(0.0144)
General Service/Lighting	(0.0662)	(0.0102)
Industrial	(0.0616)	(0.0095)

These factors are also set forth on Revised McGee Exhibit 1.

The Commission concludes that the EMF and EMF interest decrement billing factors set forth in the affidavits of Public Staff witnesses Metz and Peedin are reasonable and appropriate for use in this proceeding.

Company witness McGee 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-7, Sub 1104, should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology utilized in past DEC 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 Company witness McGee's supplemental testimony and Revised Exhibits.

Based upon the testimony and exhibits in the record, the Commission concludes that DEC's projected fuel and fuel-related cost of $1,087,140,814 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, (2) DEC's prospective fuel and fuel-related cost factors proposed in this proceeding for each of DEC's rate classes, and (3) DEC's EMF interest decrements proposed in this proceeding, excluding the regulatory fee, are all appropriate. Additionally, the Commission concludes that DEC's decrease in fuel and fuel-related costs from the amounts approved in Docket No. E-7, Sub 1104 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 1104 (excluding regulatory fee), as compared to the composite base fuel and fuel-related cost factor of 2.3182 ¢/kwh approved by the Commission in the Company's most recent general rate case, Docket No. E-7, Sub 1026:

Approved in Docket No. E-7, Sub 1104 (excluding regulatory fee):

Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Prospective Component	(0.5627)	(0.3935)	(0.1895)
EMF Component	(0.0541)	(0.0645)	(0.1640)
Total Fuel Factor	(0.6168)	(0.4580)	(0.3535)

Approved in this Docket No. E-7, Sub 1129 (excluding regulatory fee):

Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Prospective Component	(0.5354)	(0.4019)	(0.2975)
EMF Component	(0.1081)	(0.0764)	(0.0711)
Total Fuel Factor	(0.6435)	(0.4783)	(0.3686)

Summary of Differences Sub 1129 – Sub 1104 (excluding regulatory fee):

Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Prospective Component	0.0273	(0.0084)	(0.1080)
EMF Component	(0.0540)	(0.0119)	0.0929
Total Fuel Factor	(0.0267)	(0.0203)	(0.0151)

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence for this finding of fact is contained in the testimony of Company witness McGee and in the affidavits of Public Staff witnesses Peedin and 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 calculation, incorporating the conclusions reached herein, results in net fuel and fuel-related cost factors of 1.6747¢/kWh for the Residential class, 1.8399¢/kWh for the General Service/Lighting class, and 1.9496¢/kWh for the Industrial class, excluding regulatory fee, consisting of the prospective fuel and fuel-related cost factors of 1.7828¢/kWh, 1.9163¢/kWh, and 2.0207¢/kWh, EMF decrements of (0.0937)¢kWh, (0.0662)¢kWh, and (0.0616)¢/kWh, and EMF interest decrements of

(0.0144)¢/kWh, (0.0102)¢/kWh, and (0.0095)¢/kWh, for the Residential, General Service/Lighting, and Industrial classes, all respectively, excluding the regulatory fee.

IT IS, THEREFORE, ORDERED, as follows:

1. That effective for service rendered on and after September 1, 2017, DEC shall adjust the base fuel and fuel-related costs in its North Carolina retail rates of 2.3182¢/kWh, as approved in Docket No. E-7, Sub 1026, by amounts equal to (0.5354)¢/kWh, (0.4019)¢/kWh, and (0.2975)¢/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 decrements of (0.0937)¢/kWh for the Residential class, (0.0662)¢/kWh for the General Service/Lighting class, and (0.0616)¢/kWh for the Industrial class (excluding the regulatory fee). DEC shall further adjust the fuel and fuel-related costs by EMF interest decrements of (0.0144)¢/kWh, (0.0102)¢/kWh, and (0.0095)¢/kWh, for the Residential, General Service/Lighting, and Industrial classes, all respectively, excluding the regulatory fee. The EMF decrements and EMF interest decrements are to remain in effect for service rendered through August 31, 2018;

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, but not later than ten (10) days after the date that the Commission issues orders in both this Docket and in Docket No. E-7, Sub 1131; and

3. That DEC shall work with the Public Staff to prepare a notice to customers of the rate changes ordered by the Commission in this Docket, as well as in Docket No. E-7, Sub 1131, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten (10) days after the Commission issues orders in both Dockets.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of August, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

Commissioner Don M. Bailey's term expired on June 30, 2017, and he did not participate in this decision. In addition, Commissioner Daniel G. Clodfelter did not participate in this decision.

DOCKET NO. E-7, SUB 1130

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Application of Duke Energy Carolinas, LLC,	)	ORDER APPROVING DSM/EE RIDER,
for Approval of Demand-Side Management and	)	REVISING DSM/EE MECHANISM,
Energy Efficiency Cost Recovery Rider Pursuant	)	AND REQUIRING FILING OF
to G.S. 62-133.9 and Commission Rule R8-69	)	PROPOSED CUSTOMER NOTICE

HEARD: Tuesday, June 6, 2017, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; and Commissioners, Bryan E. Beatty; ToNola D. Brown-Bland; Don M. Bailey; Jerry C. Dockham; James G. Patterson; and Lyons Gray

APPEARANCES:

For Duke Energy Carolinas, LLC:

Molly McIntosh Jagannathan, Troutman Sanders LLP, 301 South College Street, Suite 3400, Charlotte, North Carolina 28202

For the Carolina Utility Customers Association, Inc.:

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

For the North Carolina Sustainable Energy Association:

Peter Ledford, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the North Carolina Justice Center and the Southern Alliance for Clean Energy:

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

For the Using and Consuming Public:

Lucy E. Edmondson and Heather D. Fennell, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

BY THE COMMISSION: General Statute 62-133.9(d) authorizes the North Carolina Utilities Commission (Commission) to approve an annual rider to the rates of electric 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 actually 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.

In the present proceeding, Docket No. E-7, Sub 1130, on March 8, 2017, Duke Energy Carolinas, LLC (DEC or the Company), filed an application for approval of its DSM/EE rider (Rider EE[1] or Rider 9) for 2018[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.

On March 21, 2017, the Commission issued an Order scheduling a hearing for June 6, 2017, establishing discovery guidelines, providing for intervention and testimony by other parties, and requiring public notice.

The intervention of the Public Staff – North Carolina Utilities Commission (Public Staff) is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). On March 14, 2017, the North Carolina Sustainable Energy Association (NCSEA) filed a petition to intervene, which was granted on March 15, 2017. The Carolina Industrial Group for Fair Utility Rates III (CIGFUR) filed a petition to intervene on March 16, 2017, which was granted on March 17, 2017. On April 4, 2017, the Carolina Utility Customers Association, Inc. filed a petition to intervene, which was granted on April 6, 2017. On May 22, 2017, the North Carolina Justice Center (NC Justice

[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 ninth Rider EE and includes components that relate to Vintages 2014, 2015, 2016, 2017, and 2018 of the cost and incentive recovery mechanism approved in Docket No. E-7, Sub 1032. For purposes of clarity, the aggregate rider is referred to in this Order as "Rider 9" or the proposed "Rider EE." Rider 9 is proposed to be effective for the rate period January 1, 2018, through December 31, 2018.

Center) and the Southern Alliance for Clean Energy (SACE) filed a petition to intervene, which was granted on May 25, 2017.

On May 19, 2017, the Public Staff filed a motion for an extension of time to May 23, 2017, in which to file intervenor testimony, and an extension to June 2, 2017, for DEC to file rebuttal testimony. The motion was granted by the Commission on May 22, 2017.

On May 23, 2017, the NC Justice Center and SACE filed the testimony of Jennifer Weiss, SACE's Energy Efficiency Policy Manager; and the Public Staff filed the affidavit and exhibits of Michael C. Maness, Director of the Accounting Division, the testimony and exhibits of Jack L. Floyd, Engineer in the Electric Division, and the testimony of John R. Hinton, Director of the Economic Research Division.

On May 31, 2017, DEC filed the supplemental and rebuttal direct testimony of Timothy J. Duff, the supplemental testimony and exhibits of witness Miller, and the supplemental exhibits of witness Evans.

On June 1, 2017, DEC filed a motion to excuse witness Miller from appearing at the June 6, 2017, expert witness hearing. On June 2, 2017, the Commission issued an order granting this motion.

On June 5, 2017 (as corrected on June 6, 2017), the Public Staff filed a letter indicating that it had reviewed the rates filed by DEC in the supplemental exhibits of DEC witness Miller and recommended their approval. The Public Staff also stated that it had completed its review of 2016 DSM/EE program costs and had found no exceptions beyond those described in the affidavit of Public Staff witness Maness filed May 23, 2017, or incorporated in the supplemental exhibits of DEC witness Miller.

The case came on for hearing as scheduled on June 6, 2017. No public witnesses appeared at the hearing.

On June 26, 2017, the Commission issued a Notice setting the due date for post- hearing filings as July 26, 2017.

On July 21, 2017, the Public Staff filed a motion requesting that the due date for post-hearing filings be extended to August 3, 2017. The Commission issued an Order granting this motion on July 24, 2017.

On August 3, 2017, NCSEA filed a post-hearing Brief, and the NC Justice Center and SACE filed a post- hearing Brief. On that same date, the Public Staff and DEC filed a Joint Proposed Order.

Other Pertinent Proceedings: Docket No. E-7, Subs 831, 938, 979, and 1032

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), the 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 (Sub 831 Pilot) with a term of four years, ending on December 31, 2013.

On February 15, 2010, the 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] For purposes of the modified save-a-watt portfolio of programs, the Company applied the vintage year concept on a calendar-year basis for administrative ease for the Company and its 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.[2]

On February 24, 2010, in Docket No. E-7, Sub 938, the Commission issued an Order Requesting Comments on the Company's Sub 938 Waiver Application. After receiving comments and reply comments, the Commission entered an Order Granting Waiver, in Part, and Denying Waiver, in Part (Sub 938 Waiver Order) on April 6, 2010. In this Order, the Commission 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

[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, as a result 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.

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.

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 in Docket No. E-7, Sub 831 (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 (Sub 979 Order), in which it approved the Evaluation, Measurement, and Verification (EM&V) agreement (EM&V Agreement) reached by the Company, SACE, and the Public Staff. Pursuant to the EM&V Agreement, for all EE programs, with the exception of the Non-Residential Smart $aver® Custom 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. 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, as approved by the Commission, 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 to be reviewed in four years. Pursuant to the Sub 1032 Stipulation, 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 for an additional incentive to further encourage kilowatt-hour (kWh) savings achievements. The Sub 1032 Mechanism also includes the following provisions, among several others: (a) it shall continue until terminated pursuant to Commission Order; (b) modifications to Commission-approved DSM/EE programs will be made using the Flexibility Guidelines; 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; (d) the EM&V Agreement shall continue to govern the application of EM&V results; and (e) 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]

[1] Each vintage under the Sub 1032 Mechanism is referred to by the calendar year of its respective rate period (e.g., Vintage 2018).

Docket No. E-7, Sub 1130

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. Based on the specific recovery of costs and incentives proposed by DEC in this proceeding, the Commission finds that it has the authority to consider and approve the relief 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 9: Appliance Recycling Program; Energy Assessments Program; EE Education Program; Energy Efficient Appliances and Devices; HVAC EE Program; Multi-Family EE Program; My Home Energy Report; Income-Qualified EE and Weatherization Program; Power Manager; Nonresidential Smart $aver Energy Efficient Food Service Products Program; Nonresidential Smart $aver Energy Efficient HVAC Products Program; Nonresidential Smart $aver Energy Efficient IT Products Program; Nonresidential Smart $aver Energy Efficient Lighting Products Program; Nonresidential Smart $aver Energy Efficient Process Equipment Products Program; Nonresidential Smart $aver Energy Efficient Pumps and Drives Products Program; Nonresidential Smart $aver Custom Program; Nonresidential Smart $aver Custom Energy Assessments Program; PowerShare; PowerShare Call Option; Small Business Energy Saver; Smart Energy in Offices; Business Energy Report Pilot; EnergyWise for Business; and Non-Residential Smart $aver Performance Incentive.

4. The Appliance Recycling program should be canceled as of December 31, 2017, and the Company should not incur further expenses for the program, unless the Company, within 60 days of this Order, provides sufficient justification for continuing the program.

5. The PowerShare Call Option program should be canceled as of January 31, 2018, and the Company should not incur further expenses for the program, unless the Company, within 60 days of this Order, provides sufficient justification for continuing the program.

6. For purposes of inclusion in Rider 9, the Company's portfolio of DSM and EE programs is cost-effective.

7. In its next rider application, DEC should address the continuing cost-effectiveness of the Non-Residential Smart $aver Performance Incentive Program, and if it is not cost-effective, provide details of plans to modify or close the program.

8. The EM&V reports filed as Evans Exhibits A, C, D, E, G, H, and I are acceptable for purposes of this proceeding and should be considered complete for purposes of calculating program impacts.

9. The EM&V reports for the Multi-Family Energy Efficiency Program (Evans Exhibit B), the Smart $aver Prescriptive Incentive Program (Evans Exhibit F), and the EM&V Report for the Small Business Energy Saver Program (Evans Exhibit J) should be revised as discussed by Public Staff witness Floyd and refiled in the next rider proceeding.

10. The EM&V recommendations concerning future EM&V reports contained in the testimony of Public Staff witness Floyd are appropriate for inclusion in future EM&V reports for the applicable EE programs, when feasible and not cost prohibitive, including certain program vintages that remain to be verified and trued up.

11. Pursuant to the Commission's Sub 938 Second Waiver Order and the Sub 1032 Order, the rate period for the purposes of this proceeding is January 1, 2018, through December 31, 2018.

12. Rider 9 includes EMF components for Vintage 2016 DSM and EE programs. Consistent with the Sub 938 Second Waiver Order, the test period for these EMF components is the period from January 1, 2016, through December 31, 2016 (Vintage 2016).

13. DEC's proposed rates for Rider 9 are comprised of both prospective and EMF components. The prospective components include factors designed to collect program costs and the PPI for the Company's Vintage 2018 DSM and EE programs, as well as the first year of NLR for the Company's Vintage 2018 EE programs; the second year of NLR for Vintage 2017 EE programs; the third year of NLR for Vintage 2016 EE programs; and the final half-year of NLR for Vintage 2015 EE programs. The EMF components include the true-up of Vintage 2016 program costs, NLR, and PPI, as well as true-ups for NLR and/or PPI for Vintages 2014 and 2015. DEC, as reflected in the supplemental testimony and exhibits of Company witness Miller and the supplemental exhibits of Company witness Evans, has calculated the components of Rider 9 in a manner that appropriately reflects the Commission's findings and conclusions in this Order, as well as the Commission's findings and conclusions as set forth in the Sub 831 Order, the Sub 831 Found Revenues Order, the Sub 938 Waiver Order, the Sub 938 Second Waiver Order, the Sub 979 Order, and the Sub 1032 Order.

14. The reasonable and prudent Rider 9 billing factor for residential customers is 0.5529 cents per kilowatt-hour (kWh), which, as is the case for all the other billing factors stated in these findings of fact, includes the regulatory fee.

15. The reasonable and prudent Rider 9 Vintage 2018 EE prospective billing factor for non-residential customers who do not opt out of Vintage 2018 of the Company's EE programs is 0.2769 cents per kWh.

16. The reasonable and prudent Rider 9 Vintage 2018 DSM prospective billing factor for non-residential customers who do not opt out of Vintage 2018 of the Company's DSM programs is 0.0734 cents per kWh.

17. The reasonable and prudent Rider 9 Vintage 2017 prospective EE billing factor for non-residential customers who participated in Vintage 2017 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2017 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2018) is 0.0456 cents per kWh.

18. The reasonable and prudent Rider 9 Vintage 2016 prospective EE billing factor for non-residential customers who participated in Vintage 2016 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2016 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2018) is 0.0638 cents per kWh.

19. The reasonable and prudent Rider 9 Vintage 2015 prospective EE billing factor for non-residential customers who participated in Vintage 2015 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2015 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2018) is 0.0197 cents per kWh.

20. The reasonable and prudent Rider 9 Vintage 2016 EE EMF billing factor for non-residential customers who participated in Vintage 2016 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2016 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2018) is 0.1261 cents per kWh.

21. The reasonable and prudent Rider 9 Vintage 2016 DSM EMF billing factor for non-residential customers who participated in Vintage 2016 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2016 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2018) is 0.0015 cents per kWh.

22. The reasonable and prudent Rider 9 Vintage 2015 EE EMF billing factor for non-residential customers who participated in Vintage 2015 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2015 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2018) is 0.0193 cents per kWh.

23. The reasonable and prudent Rider 9 Vintage 2015 DSM EMF billing factor for non-residential customers who participated in Vintage 2015 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2015 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2018) is (0.0024) cents per kWh.

24. The reasonable and prudent Rider 9 Vintage 2014 EE EMF billing factor for non-residential customers who participated in Vintage 2014 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2014 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2018) is 0.0005 cents per kWh.

25. The reasonable and prudent Rider 9 Vintage 2014 DSM EMF billing factor for non-residential customers who participated in Vintage 2014 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2014 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2018) is (0.0006) cents per kWh.

26. The agreement between the Company and Public Staff to adjust the Vintage Year 2018 Portfolio Performance Incentive (PPI) by $6.75 million is reasonable and should be approved.

27. DEC should continue to leverage the Collaborative to: (a) continue collaborative working group discussions for low-income, multifamily, manufactured housing and industrial programs, and include a narrative of these discussions in its next rider filing; (b) discuss how DEC's behavioral and lighting programs can be used to encourage and improve cross-participation with other programs; (c) discuss the potential inclusion in DEC's portfolio of any new programs based on best practices from around the country, including strategic energy management for industrial customers, comprehensive whole house retrofit programs, an enhanced multi-family affordable housing program, a multi-family new construction program, a manufactured housing program, and additional low-income residential EE programs, with parties proposing these programs providing sufficient and applicable information for DEC to evaluate the cost-effectiveness of the programs; and (d) continue to discuss how to increase program participation and impacts with an emphasis on increasing the participation of opt-out eligible customers as discussed in the testimony of NC Justice Center and SACE witness Weiss.

28. The revisions to the Sub 1032 Mechanism as set out in Maness Exhibit II are reasonable and should be approved effective January 1, 2018.

EVIDENCE FOR FINDINGS AND CONCLUSIONS 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.

G.S. 62-133.9 grants the Commission the authority 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 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 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 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.

G.S. 62-133.9, along with Commission Rules R8-68 and Rule 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 as well as appropriate utility incentives, potentially including "[a]ppropriate 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 Sub 1032 Mechanism, the Company filed an application for approval of such annual rider (Rider 9) and the cost recovery and utility incentives the Company seeks through Rider 9 are based on the Company recovering DSM/EE program costs, NLR (net of found revenues), and a PPI incentive related to the DSM and EE programs approved in the Sub 1032 Order and those approved following the Sub 1032 Order.[1] Recovery of these costs and utility incentives is also consistent with 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 relief the Company is seeking in this docket.

EVIDENCE FOR FINDING AND CONCLUSION NO. 3

The evidence for this finding can be found in DEC's Application, the testimony and exhibits of Company witnesses Evans and Miller, the affidavit of Public Staff witness Floyd, and various Commission orders.

DEC witness Miller's testimony and exhibits show that the Company's request for approval of Rider 9 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: Appliance Recycling Program; Energy Assessments Program; EE Education Program; Energy Efficient Appliances and Devices; HVAC EE Program; Multi-Family EE Program; My Home Energy Report; Income-Qualified EE and Weatherization Program; Power Manager; Nonresidential Smart $aver Energy Efficient Food

[1] The programs approved by the Commission following the Sub 1032 Order are as follows: Smart Energy in Offices (formerly, the Smart Energy Now Pilot), which was approved in Docket No. E-7, Sub 961 on August 13, 2014; Small Business Energy Saver, which was approved on August 13, 2014 in Docket No. E-7, Sub 1055; the Business Energy Report Pilot, which was approved in Docket No. E-7, Sub 1081 on August 19, 2015; and EnergyWise for Business, which was approved in Docket No. E-7, Sub 1093 on October 27, 2015. The Company's Energy Management Information Services Pilot has since been discontinued.

Service Products Program; Nonresidential Smart $aver Energy Efficient HVAC Products Program; Nonresidential Smart $aver Energy Efficient IT Products Program; Nonresidential Smart $aver Energy Efficient Lighting Products Program; Nonresidential Smart $aver Energy Efficient Process Equipment Products Program; Nonresidential Smart $aver Energy Efficient Pumps and Drives Products Program; Nonresidential Smart $aver Custom Program; Nonresidential Smart $aver Custom Energy Assessments Program; PowerShare; PowerShare Call Option; Small Business Energy Saver; Smart Energy in Offices; Business Energy Report Pilot; EnergyWise for Business; and Non-Residential Smart $aver Performance Incentive.

In his affidavit, Public Staff witness Floyd also listed the DSM/EE programs and pilots for which the Company seeks cost recovery and noted that each of these programs and pilots has received approval as a new DSM or EE program and is eligible for cost recovery in this proceeding under G.S. 62-133.9.

Thus, the Commission finds and concludes that each of the programs and pilots listed by witnesses Evans and Floyd has received Commission approval as a new DSM or EE program or pilot and is, therefore, eligible for cost recovery in this proceeding under G.S. 62-133.9.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 4-5

The evidence in support of these findings can be found in the testimony and exhibits of DEC witness Evans and the testimony of Public Staff witness Floyd.

Evans Exhibit 3 indicates that DEC did not incur expenses in 2016 related to either the Appliance Recycling or PowerShare Call Option programs. DEC witness Evans testified that the Appliance Recycling Program, which is currently suspended, produced 3 percent of forecasted avoided costs and 3 percent of both forecasted energy and capacity savings largely due to the bankruptcy of the program vendor. He noted that the Company continues to evaluate the long-term viability of the program and is exploring potential new program vendors.

Public Staff witness Floyd testified that DEC has not indicated that it plans to resume the Appliance Recycling program, as reflected on page 4 of 94 of Evans Exhibit 6. He further indicated that the PowerShare Call Option continues to have no participation, as shown on page 78 of 94 of Evans Exhibit 6. Witness Floyd stated that absent significant changes regarding these programs' feasibility, these programs should be canceled as of December 31, 2017, and the Company should not incur further expenses for either program.

The Commission notes that pursuant to Attachments 1 and 2, Paragraph 2(c) of the settlement agreements of Duke Energy Carolinas, LLC and Progress Energy Carolinas, Inc., with CIGFUR and CUCA, respectively, filed in Docket Nos. E-2, Sub 998 and E-7, Sub 986, on September 7, 2012, DEC agreed to support the PowerShare Call Option for five years from the effective date of the initial tariff (January 24, 2013) or until withdrawn.

Based on the evidence in the record and its entirety, the Commission therefore, concludes that the Appliance Recycling program should be canceled as of December 31, 2017, and the PowerShare Call Option program should be canceled as of January 31, 2018, and the Company should not incur further expenses for either program, unless the Company, within 60 days of this Order, provides sufficient justification for continuing either program.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 6-7

The evidence for these findings can be found in the testimony and exhibits of Company witness Evans, the rebuttal and supplemental testimony of DEC witness Duff, the testimony and exhibits of Public Staff witness Floyd, and the testimony of NC Justice and SACE witness Weiss.

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 2018 period, the results of which are incorporated in Evans Exhibit 7. The analysis did not include any values for DEC's Appliance Recycling Program, as no costs for this Program were included in Vintage 2018 due to its current suspension. DEC's calculations indicate that, with the exception of the Income-Qualified EE and Weatherization Program (which was not cost-effective at the time it was approved by the Commission) and the Residential HVAC EE Program, the aggregate portfolio continues to be cost-effective.

Concerning the Residential HVAC EE Program, witness Evans noted that it scored a 0.99 under the Total Resource Cost (TRC) test. Because this result is so close to the 1.00 threshold for cost-effectiveness, as well as DEC's additional planned program modifications intended to enhance the Program's overall cost-effectiveness, DEC does not believe that the HVAC EE Program should be discontinued at this time. Public Staff witness Floyd testified that the Residential HVAC EE program has struggled to remain cost-effective for several years because of (1) higher efficiency standards mandated by the federal government, which has increased baselines for efficiency, and (2) the need for large participant incentives to overcome the out-of-pocket costs to participants. He further testified that DEC and the Public Staff addressed the issue of underperformance and cost effectiveness of the Residential HVAC EE program in a stipulation and agreement filed February 4, 2016, in Docket No. E-7, Sub 1032. In its February 9, 2016 Order on Application For Approval of Program Modifications, the Commission approved DEC's proposed modifications to the Residential HVAC EE program and granted DEC until March 1, 2017, to achieve projected cost effectiveness under the TRC test. Witness Floyd noted that the Commission subsequently granted DEC approval to continue offering the Residential HVAC EE program beyond March 31, 2017, in its Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice in Docket No. E-7, Sub 1105.

Public Staff witness Floyd stated in his testimony that he reviewed DEC'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. He indicated that each program was cost-effective under both the UC and the TRC tests, with the exception of the Income-Qualified EE and Weatherization Program (TRC of 4.51 and a UC of 0.49) and the Residential HVAC EE Program (TRC of 0.99 and a UC of 1.60). Witness Floyd stated that his review indicated that the portfolio as a whole remains cost-effective under all four tests. Public Staff witness Floyd noted that several programs remain cost-effective, but have TRC scores that have decreased since the 2016 DSM/EE rider proceeding; similarly, several programs have increased in cost-effectiveness since the 2016 proceeding.

Witness Floyd testified that the Public Staff and DEC had differing interpretations of Paragraph 69 of the Sub 1032 Mechanism as to the appropriate avoided costs to be used in calculations of cost-effectiveness. Paragraph 69 of the Mechanism requires DEC to update both the avoided capacity and avoided energy costs if the current avoided capacity cost rates have changed by 15% or more or the avoided energy cost rates changed by 20% or more. Witness Floyd stated that DEC made its filing in this proceeding in accordance with its belief that neither the 15% or 20% change had occurred; while the Public Staff believed that there had been a change in the rates to require an update of avoided costs. The Public Staff and DEC resolved this issue by agreeing to a monetary adjustment to the Vintage Year 2018 PPI, revisions to the language of Paragraph 69, and other minor changes to the Sub 1032 Mechanism. The resolution also provided specific recommendations regarding three programs that appear to be marginal or not cost-effective if avoided costs had been updated: the Business Energy Report pilot, the Non-Residential Smart $aver Performance Incentive program, and the Residential HVAC EE program.

Regarding the Business Energy Report, Public Staff witness Floyd noted that as the pilot is in the second year of its three-year duration, DEC is monitoring the pilot's performance and may seek to discontinue it early if performance does not improve. He pointed out that under the Sub 1032 Mechanism, if the pilot is not developed into a cost-effective program going forward, DEC will not be able to recover any PPI or NLR for pilot. DEC must demonstrate that the program can be cost-effective by the end of the pilot if it seeks to have it approved as a fully commercialized program. Therefore, he did not recommend any changes for this pilot.

The second program witness Floyd discussed that would be marginal or not cost-effective if avoided costs were updated was the Non-Residential Smart $aver Performance Incentive program, which was approved in the fall of 2016 and launched in January 2017. He did not recommend any action at this time as it is difficult to assess the actual cost-effectiveness of the program at such an early stage. Witness Floyd noted that by the time of the 2018 rider filing, the program will have matured and its cost-effectiveness could better be assessed.

Public Staff witness Floyd recommended that the third program, the Residential HVAC EE program, either be terminated or be substantially changed. He noted that the program had struggled to remain cost-effective for several years because of higher efficiency standards and the need for large participant incentives to overcome the out-of-pocket costs to participants. Witness Floyd explained that the program has both referral and non-referral measures. His analysis indicated that even using updated avoided costs, the referral measures remained cost-effective. However, the non-referral measures are not cost-effective, and 99% of the program's participation is in non-referral measures. He recommended that if the program could not attain cost-effectiveness, DEC should either terminate the program effective March 31, 2018, or modify the program to transition from non-referral channel measures that are not cost-effective under the TRC to be more heavily focused on referred measures.

In his rebuttal and supplemental testimony, DEC witness Duff stated that the Company has agreed to monitor these three programs closely and has developed strategies for each of the three programs. With respect to the Business Energy Report Pilot Program, witness Duff stated that the Company would likely to file a request to terminate the program in the next few weeks due to its cost-effectiveness, preliminary internal savings analysis, and potential vendor viability issues.[1] As to the Non-Residential Smart $aver Performance Incentive Program, DEC witness Duff agreed that the program needs more time before its cost-effectiveness scores should lead to any specific action other than ongoing monitoring and reporting in the Collaborative. With respect to the Residential HVAC EE Program, witness Duff indicated that the Company is in the process of preparing a filing requesting to make a number of modifications to the program to enhance its cost-effectiveness, including a modification designed to improve the ratio of customers participating in the more cost-effective referral measures.[2]

NC Justice Center and SACE witness Weiss testified that DEC's DSM/EE portfolio had been cost-effective from the start. She noted that cost-effectiveness tests are dependent on avoided cost rates and would need to be updated as avoided costs change.

The Commission therefore concludes that DEC's portfolio of DSM and EE programs is cost-effective and eligible for inclusion in Rider 9. In accordance with its Order issued on July 25, 2017, terminating the Business Energy Report program, the appropriate ratemaking treatment for this program will be addressed in DEC's 2018 cost recovery rider. Additionally, the Commission concludes that in its next rider application, DEC should address the continuing cost-effectiveness of the Non-Residential Smart $aver Performance Incentive Program and the Residential HVAC EE Program, and if either is not cost-effective, provide details of plans to modify or close the program.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 8-10

The evidence in support of these findings can be found in the testimony and exhibits of DEC witness Evans and the testimony of Public Staff witness Floyd.

DEC witness Evans testified regarding the EM&V process, activities, and results presented in this proceeding. He explained that the EMF component of Rider 9 incorporates actual customer participation and evaluated load impacts determined through EM&V and applied pursuant to the EM&V Agreement. In addition, actual participation and evaluated load impacts are used prospectively to update estimated NLR. In this proceeding, the Company submitted, as exhibits to witness Evans' testimony, detailed completed EM&V reports or updates for the following programs: Residential Income-Qualified EE and Weatherization Assistance for Residential Neighborhoods Program 2015; Residential Multi-Family EE Program 2014-2015; Power Manager

[1] On June 15, 2017, DEC filed for approval to terminate its Business Energy Report Pilot Program in Docket No. E-7, Sub 1081. The Commission issued an Order terminating the program on July 25, 2017.

[2] On July 20, 2017, DEC filed for approval of these modifications to its HVAC EE program in Docket No. E-7, Sub 1032. These modifications to enhance cost-effectiveness have not yet been ruled on by the Commission as of the date of this Order.

Load Control Service Program 2015; Non-Residential Smart $aver Energy Efficient Products and Assessment Program - Custom Projects 2013-2015; Non-Residential Smart $aver Energy Efficient Products and Assessment Program - Prescriptive 2012-2014; Non-Residential Smart $aver Energy Efficient Products and Assessment - Prescriptive 2013-2015; PowerShare Non-Residential Load Curtailment 2014; PowerShare Non-Residential Load Curtailment 2015; Residential Energy Efficient Appliances and Devices – Save Energy and Water Kit 2014-2015; and Small Business Energy Saver 2015.

In his testimony, Public Staff witness Floyd testified that he reviewed previous Commission Orders to determine if DEC had complied with provisions regarding EM&V contained in those orders. In addition, witness Floyd stated that DEC had adopted his EM&V-related recommendations made in the 2016 DSM/EE rider proceeding, Docket No. E-7, Sub 1105 (Sub 1105), to the extent these recommendations are applicable to the EM&V reports filed in this proceeding. He noted that it was his understanding that DEC's EM&V evaluator intended to incorporate these recommendations in future EM&V reports. Witness Floyd also provided recommendations concerning the content of future EM&V studies for particular EE programs, noting that DEC's implementation of these recommendations would be subject to the consideration of whether the cost would outweigh the benefit. Public Staff witness Floyd recommended in this proceeding that:

(1) Future evaluations of the Residential Multi-Family Energy Efficiency program include a billing analysis and more specific data on bulbs being replaced. If it is not feasible to provide this analysis or data, the evaluator should explain why it is not feasible.[1]

(2) If the evaluator continues to rely on an engineering analysis to calculate measure impacts for the Save Energy and Water Kits, the evaluator should address the technological limits of water heaters when assessing the length of showers used to calculate impacts. Future engineering analyses should either discard outliers or incorporate an assessment of the limitations of water heaters to produce savings.

(3) Future evaluations of the Small Business Energy Saver program should: (a) incorporate HVAC interactive effects and update the coincidence factors for lighting measures, and (b) begin tracking the heating and cooling types of participants to improve estimates of the HVAC interaction factors.

(4) Future evaluations of the Non-Residential Smart $aver Energy Efficient Products and Assessments - Prescriptive program rely on metering studies in determining the hours-of-use (HOU) for lighting measures installed in commercial buildings consistent with the Uniform Methods Project.

[1] DEC has indicated to the Public Staff that it already implemented this recommendation concerning the removed bulbs in 2016.

Public Staff witness Floyd also requested that if DEC or its evaluator determines that adoption of these recommendations is cost prohibitive, then DEC should provide a cost analysis in its next rider proceeding.

Witness Floyd concluded that, with the exception of the Multi-Family Energy Efficiency Program EM&V Report (Evans Exhibit B), the Smart $aver Prescriptive Incentive Program EM&V Report (Evans Exhibit F), and the EM&V Report for the Small Business Energy Saver Program (Evans Exhibit J), the EM&V of the vintages of the measures covered by the remaining reports filed in this proceeding should be considered complete. With respect to the Multi-Family Energy Efficiency Program EM&V Report, witness Floyd discussed several issues the Public Staff had found with the calculations, and recommended that the evaluator address these issues and that DEC file a revised report. He explained that any revisions would affect Vintages 2016 through 2018. Witness Floyd noted that the Public Staff found similar issues with the Smart $aver Prescriptive Incentive Program EM&V report, and recommended that the evaluator address the Public Staff's concerns and that DEC file a revised report. Witness Floyd asserted that any revisions would affect Vintages 2015 through 2018. Finally, witness Floyd indicated that the Small Business Energy Saver Program EM&V Report should be revised to correct an error, which he testified, would affect Vintages 2016 through 2018.

Public Staff witness Floyd also recommended that while DEC should minimize the cost of EM&V where possible and appropriate, the EM&V report produced should evidence sufficient rigor to provide confidence in the results. He explained that the effort or rigor necessary for a particular EM&V report should be predicated on the extent of savings from a program or measure, the participation levels, and the cost of delivering cost-effective DSM and EE programs. The frequency of EM&V should be controlled by the level of savings a program provides to the portfolio, as well as the sophistication and rigor needed to conduct an appropriate EM&V analysis.

With the exception of those EM&V-related recommendations made by Public Staff witness Floyd for revisions to Evans Exhibits B, F, and J and regarding future EM&V (none of which were disputed by DEC), 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, C, D, E, G, H, and I are acceptable for purposes of this proceeding and should be considered complete for purposes of calculating program impacts; that the EM&V reports for the Multi-Family Energy Efficiency Program (Evans Exhibit B), the Smart $aver Prescriptive Incentive Program (Evans Exhibit F), and the EM&V Report for the Small Business Energy Saver Program (Evans Exhibit J) should be revised as discussed by Public Staff witness Floyd and refiled in the next rider proceeding; and that the EM&V recommendations concerning future EM&V reports contained in the testimony of Public Staff witness Floyd should be approved and applied in future EM&V reports for the applicable EE programs, when feasible and not cost prohibitive, including certain program vintages that remain to be verified and trued up.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 11-12

The evidence in support of these findings can be found in the Sub 938 Second Waiver Order; the Sub 1032 Order; the testimony of Company witnesses Miller and Evans; and the affidavit of Public Staff witness Maness. The rate period and the scope of the EMF components of

Rider 9 are consistent with the Commission's ruling in the Sub 938 Second Waiver Order and the Sub 1032 Order, and are uncontroverted by any party.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 13-26

The evidence in support of these findings and conclusions can be found in the Sub 831 Order, the Sub 831 Found Revenues Order, the Sub 938 Waiver Order, the Sub 938 Second Waiver Order, the Sub 979 Order, and the Sub 1032 Order; as well as in the Company's Application, as set forth in the direct and revised testimony and exhibits of Company witnesses Miller and Evans; and in the affidavit of Public Staff witness Maness and the testimony of Public Staff witness Floyd. On March 8, 2017, DEC filed its Application seeking approval of Rider 9, which includes the formula for calculation of Rider EE, as well as the proposed billing factors to be effective for the 2018 rate period. Company witness Miller and Public Staff witness Maness testified that the methods by which DEC has calculated its proposed Rider EE are consistent with the Sub 1032 Stipulation and Sub 1032 Mechanism approved in the Sub 1032 Order.

Witness Miller provided an overview of the Sub 1032 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. Company witness Miller explained that the PPI is calculated, pursuant to the Sub 1032 mechanism, by multiplying the net dollar savings achieved by the system portfolio of DSM and EE programs by a factor of 11.5%. The system amount of PPI is then allocated to North Carolina retail customer classes in order to derive customer rates. 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 on an annual basis.

The Company is allowed to 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. DEC 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 <u>estimated</u> North Carolina retail kW and kWh reductions applicable to EE programs by rate schedule, and reducing this amount by estimated found revenues. 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. The NLR totals for residential and non-residential customers are then reduced by North Carolina retail found revenues computed using the weighted average lost revenue rates for each customer class. Witness Miller explained that for the EMF components of Rider EE, NLR are calculated by multiplying the fixed cost portion of the tariff rates by the <u>actual and verified</u> North Carolina retail kW and kWh reductions applicable to EE programs by rate schedule, and then reducing this amount by actual found revenues.

[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 the purpose of adopting and implementing new DSM and EE measures previously approved pursuant to Rule R8-68.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

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. Additionally, he stated that the Company has continued the practice the Commission approved in the Sub 1073 Order 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.

DEC witness Miller testified that in each of its annual rider filings, DEC performs an annual true-up process for the prior calendar year vintages. 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. She stated that 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. 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.

Under the Sub 1032 Stipulation, as witness Miller explained, the Company has implemented deferral accounting for over- and under-recoveries of costs eligible for recovery through the annual DSM/EE rider. 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. She testified that the methodology used for the calculation of interest is the same as that typically utilized for the Company's Existing DSM Program Rider proceedings. Pursuant to Commission Rule R8-69(c)(3), the Company will not accrue a return on NLR or the PPI.

Under the Sub 1032 Stipulation, as with the Sub 938 First Waiver Order and the Sub 831 Pilot, qualifying non-residential customers are allowed to opt-out of the DSM and/or EE portion of Rider EE during annual election periods. Witness Miller 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. Company witness Miller explained that the Sub 1032 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. 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.

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 non-residential, by the forecasted sales for the rate period for the customer class. Witness Miller noted that for non-residential rates, the forecasted sales exclude the estimated sales to customers who have elected to opt-out of paying Rider EE and that the non-residential billing factors are separately computed for each vintage.

Company 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. 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. Witness Miller noted that the portion of revenue requirements related to NLR for EE programs is not allocated to the North Carolina retail jurisdiction, but rather is specifically computed based on the kilowatt (kW) and kWh savings of North Carolina retail customers.

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. DEC witness Miller testified that 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.

Witness Miller stated 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. Witness Miller asserted that 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.

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. 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 EE and/or DSM 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.

Prospective Components of Rider 9

In the testimony of DEC witness Miller, she stated that Rider 9 consists of five prospective components, all of which are related to the Sub 1032 Mechanism: (1) a prospective Vintage 2018 component designed to collect program costs and the PPI for DEC's 2018 vintage of DSM programs; (2) a prospective Vintage 2018 component to collect program costs, the PPI, and the first year of NLR for DEC'S 2018 vintage of EE programs; (3) a prospective Vintage 2017 component designed to collect the second year of estimated NLR for DEC'S 2017 vintage of EE programs; (4) a prospective Vintage 2016 component designed to collect the third year of estimated NLR for DEC'S 2016 vintage of EE programs; and (5) a prospective Vintage 2015 component designed to collect the final half-year of estimated NLR for DEC'S 2015 vintage of EE programs.

As testified to be DEC witness Miller and also by Public Staff witness Maness, the rate period for the prospective components of Rider 9 is January 1, 2018, through December 31, 2018, pursuant to the Sub 938 Second Waiver Order and the Sub 1032 Order.

DEC witness Miller testified that the prospective revenue requirements for Vintage 2015 are determined separately for residential and non-residential customer classes and are based on the final half-year of estimated NLR for the Company's Vintage 2015 EE programs. 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 1026, which became effective September 25, 2013 (Sub 1026 Rates).

Witness Miller further testified that the prospective revenue requirements for Vintage 2016 are determined separately for residential and non-residential customer classes and are based on the third year of estimated NLR for the Company's Vintage 2016 EE programs. The amounts are based on estimated North Carolina retail kW and kWh reductions and the Sub 1026 Rates.

According to DEC witness Miller, the prospective revenue requirements for Vintage 2017 are determined separately for residential and non-residential customer classes and are based on the second year of estimated NLR for the Company's Vintage 2017 EE programs. The amounts are based on estimated North Carolina retail kW and kWh reductions and the Sub 1026 Rates.

Witness Miller stated that the prospective revenue requirements for Vintage 2018 EE programs include estimates of program costs, the PPI, and the first year of NLR determined separately for residential and non-residential customer classes. The program costs and shared savings incentive are computed at the system level and allocated to North Carolina retail operations. The NLR for EE programs are based on estimated North Carolina retail kW and kWh reductions and the Sub 1026 Rates.

On May 31, 2017, DEC witness Miller filed supplemental testimony and exhibits reflecting prospective billing factors for Rider 9 of 0.4458 cents per kWh for all North Carolina retail residential customers, 0.2769 cents per kWh for non-residential Vintage 2018 EE participants, 0.0734 cents per kWh for non-residential Vintage 2018 DSM participants, 0.0456 cents per kWh for non-residential Vintage 2017 EE participants, 0.0638 cents per kWh for non-residential Vintage 2016 EE participants, and 0.0197 cents per kWh for non-residential Vintage 2015 EE participants.

EMF Components of Rider 9

In her testimony, DEC witness Miller describes the EMF components included in Rider 9: (1) a true-up of Vintage 2014 shared savings and participation for DSM/EE programs based on additional EM&V results received; (2) a true-up of Vintage 2015 shared savings and participation for DSM/EE programs based on additional EM&V results received; (3) a true-up of Vintage 2016 program costs, shared savings and participation for DSM/EE programs.

Company witness Miller testified that pursuant to the Sub 938 Second Waiver Order and the Sub 1032 Order, the "test period" for the Vintage 2016 EMF component is January 1, 2016, through December 31, 2016. As the Sub 938 Second Waiver Order allows the EMF to cover multiple test periods, the test period for the Vintage 2015 EMF component is January 1, 2015, through December 31, 2015, and the test period for the Vintage 2014 EMF component is January 1, 2014, through December 31, 2014.

Witness Miller explained the updates to the Vintage 2016 estimate filed in 2015 that comprise the Vintage 2016 EMF component of Rider 9. Estimated participation for Vintage 2016 was updated for actual participation for the period January through December 2016. With regard to NLR, estimated participation for the Year 1 Vintage 2016 estimate assumed a January 1, 2016, sign-up date and used a half-year convention, while the NLR Year 1 Vintage 2016 true-up was updated for actual participation for the period January through December 2016 and actual 2016 lost revenue rates. Found revenues for Year 1 of Vintage 2016 were trued up according to Commission-approved guidelines. To reflect the results of EM&V, Vintage 2016 estimated avoided cost savings were updated pursuant to the EM&V Agreement. Finally, while the Vintage 2016 estimate included only the programs approved prior to the filing of the estimated Vintage 2016 revenue requirement, the Vintage 2016 true-up was updated for new programs and pilots approved and implemented during Vintage 2016. For DSM programs, the Vintage 2016 true-up reflects the actual quantity of demand reduction capability for the Vintage 2016 period.

DEC witness Miller testified that actual year one (2016) NLR for Vintage 2016 were calculated using actual kW and kWh savings by North Carolina retail participants by customer class in 2016, based on actual participation and load impacts applied according to the EM&V Agreement. The rates applied to the kW and kWh savings are those in effect for 2016, reduced by fuel and variable operation and maintenance costs. NLR were then offset by actual found revenues for Year 1 NLR of Vintage 2016. NLR were calculated by rate schedule within the residential and non-residential customer classes.

DEC witness Miller also described the basis for the Vintage 2015 EMF component of Rider 9. She explained that avoided costs and NLR for Vintage 2015 EE programs were trued-up based on updated EM&V participation results. Avoided costs for Vintage 2015 DSM were also trued-up to correct participation results. She explained that the actual kW and kWh savings were as experienced during the period January 1, 2015, through December 31, 2015. 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.

DEC witness Miller explained the basis for the Vintage 2014 EMF component of Rider 9. She explained that avoided costs and NLR for Vintage 2014 EE programs were trued-up based on updated EM&V participation results. She explained that the actual kW and kWh savings were as experienced during the period January 1, 2014, through December 31, 2014. 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.

Overall, as set forth on Supplemental Miller Exhibit 1, the Company proposed an EMF of 0.1071 cents per kWh for its North Carolina retail residential customers, 0.1261 cents per kWh for non-residential Vintage 2016 EE participants, 0.0015 cents per kWh for non-residential Vintage 2016 DSM participants, 0.0193 cents per kWh for non-residential Vintage 2015 EE participants, (0.0024) cents per kWh for non-residential Vintage 2015 DSM participants, 0.0005 cents per kWh for non-residential Vintage 2014 EE participants, and (0.0006) cents per kWh for non-residential Vintage 2014 DSM participants.

Public Staff Review of Company Rider 9 Calculations

As discussed above, Public Staff witness Floyd filed testimony in this proceeding discussing several EM&V-related topics and issues related to the Company's filing. Public Staff witness Maness testified that 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 (a) were calculated in accordance with the Sub 1032 Stipulation, as applicable, as well as other relevant Commission orders, and (b) otherwise adhered to sound ratemaking concepts and principles. With the exception of the items discussed below, which were subsequently corrected by DEC's supplemental filing, witness Maness testified that he believes that the Company has calculated the Rider 9 billing factors in a manner consistent with 62-133.9, Commission Rule R8-69, the Sub 1032 Stipulation, and other relevant Commission orders.

Public Staff witness Maness noted that in the course of his investigation, the Public Staff and DEC became aware that the Company had inadvertently failed to reduce the customer class kWh sales amounts used as the denominators in its billing factor calculations to reflect the fact that certain lighting rate schedules are not subject to the DSM/EE Rider. Per the Company, this error understated the Rider 9 revenue requirement by approximately $4.7 million (approximately 2% of the total filed revenue requirement). DEC indicated to the Public Staff that it would prefer to make the adjustments in next year's DSM/EE Rider filing and witness Maness indicated in his affidavit that the Public Staff had no objection to this proposal.

Witness Maness also 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, 2016. 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 was intended to test whether the costs included by the Company in the DSM/EE riders are valid costs of approved DSM and EE programs.

Public Staff witness Maness stated that during the course of the Public Staff's review of samples of Vintage Year 2016 program costs, the Public Staff and DEC discovered one exception, totaling $15,942, related to a misallocation to DEC of general DSM/EE charges from a vendor that should also have been allocated to several of the Company's non-Carolinas affiliates. As a result of the discovery of this exception, the Company examined its records and found additional errors associated with the allocation of charges from this vendor during 2016; the total of these errors amounts to approximately $175,000 on a total DEC basis. Public Staff witness Maness testified that this error was corrected in the Supplemental Testimony and Exhibits of Carolyn Miller, and was acceptable to the Public Staff, as indicated by the letter filed by the Public Staff on June 5, 2017 (as corrected on June 6, 2017).

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

As discussed by Public Staff witnesses Floyd and Maness, the Public Staff and DEC had differing interpretations as to the appropriate avoided costs to be used in calculating Rider 9 pursuant to Paragraph 69 of the Sub 1032 Mechanism. Paragraphs 68 and 69 of the Sub 1032 Mechanism state:

> 68. For the PPI for Vintage Year 2014, the per kW avoided capacity costs used to calculate avoided cost savings shall be those reflected in the filing by Duke Energy Carolinas in Docket No. E-100, Sub 136. The per kWh avoided energy costs shall be those reflected in or underlying the most recently filed integrated resource plan (IRP)...
>
> 69. For the PPI for Vintage Years 2015, 2016, and 2017, the presumptive per kW avoided capacity costs and per kWh avoided energy costs used to calculate avoided cost savings shall be those determined pursuant to paragraph 68 above. However, if at the time of initial estimation of the PPI for each of those years, either (a) the Company's per kWh avoided energy costs calculated for the purposes of the Company's annual IRP or resource plan update filings have increased or decreased by 20% or more or (b) the Company's per kW avoided capacity costs reflected in the rates approved in the biennial avoided cost proceedings have increased or decreased by 15% or more, the avoided costs (both energy and capacity) will be updated for purposes of the DSM/EE rider proceeding.

Public Staff witness Floyd testified that the Public Staff believed that Paragraph 69 of the Mechanism requires DEC to update both the avoided capacity and avoided energy costs if the current avoided capacity cost rates have changed by 15% or more or the avoided energy cost rates changed by 20% or more. DEC indicated to the Public Staff and made its filing in this proceeding in accordance with its belief that neither the 15% or 20% change had occurred. According to witness Floyd, the Public Staff believes that under existing Paragraph 69, the requisite change had occurred to require an avoided cost update in the current proceeding.

Witness Maness testified that the "ratchet" that would cause avoided capacity and energy costs to be updated for purposes of the DSM/EE Rider proceeding had been triggered for purposes of the PPI to be calculated for Vintage Year 2018. The Company's interpretation caused it to believe that the ratchet had not been triggered. Had new avoided cost rates been updated in a manner consistent with the Public Staff's interpretation of Paragraph 69, the Vintage Year 2018 PPI would have been reduced by approximately \$9.5 million (approximately 32% of the total estimated 2018 PPI), based on calculations performed by the Company.

Witness Maness indicated that the Public Staff and DEC had reached a comprehensive agreement that resolved their differences regarding Vintage Year 2018 and would change the method used to determine avoided capacity and energy costs on a going forward basis. Pursuant to this agreement, the Company reduced its proposed Vintage Year 2018 PPI (which is included in the Rider 9 calculations) by \$6,750,000. This reduction to the Vintage 2018 PPI was incorporated in the Supplemental Testimony and Exhibits of Carolyn Miller, and was reviewed by the Public Staff as indicated by its letter filed on June 5, 2017. This same monetary reduction will also be applied to the eventual true-up of the Vintage Year 2018 PPI in future rider proceedings.

Witness Maness also noted that the Company has continued to use its net-of-tax rate of return to calculate the interest amount on over-recoveries in this DSM/EE Rider 9 proceeding, rather than the 10% rate normally used by the Commission for over-recoveries in certain other rider proceedings. However, Witness Maness found the impact of this rate differential to be immaterial to the DSM/EE billing factors. Witness Maness stated that the Public Staff reserved the right to raise this issue in the future.

In its June 5, 2017, letter, the Public Staff indicated that it had reviewed the adjustments made by the Company in the Supplemental Filing, and the methods used to flow those adjustments through the calculations of the proposed billing factors. As a result of this review, the Public Staff stated that it believes that the adjustments and resulting rate calculations made by the Company are appropriate and reasonable. Further, the Public Staff noted it had found no further exceptions or necessary adjustments to test year (Vintage Year 2016) DSM/EE program costs. Therefore, the Public Staff recommended that the Commission approve the proposed rates set forth in the Company's Supplemental Filing of May 31, 2017.

Conclusions on Calculations of Rider EE

Based on the evidence provided, the Commission finds and concludes that the components of Rider 9, as revised in Supplemental Miller Exhibit 1, are appropriate and in compliance with the Commission's findings and conclusions herein, as well as the Commission's findings and conclusions as set forth in the Sub 831 Found Revenues Order, the Sub 938 First Waiver Order, the Sub 938 Second Waiver Order, the Sub 979 Order, and the Sub 1032 Order. The Commission also finds that it is appropriate for DEC to correct its understatement of the Rider 9 revenue requirement by approximately $4.7 million (approximately 2% of the total filed revenue requirement) in next year's DSM/EE Rider filing. The Commission further finds and concludes that the agreement between the Company and Public Staff to reduce its proposed Vintage Year 2018 PPI (which is included in the Rider 9 calculations) by $6,750,000, and to apply this same monetary reduction to the eventual true-up of the Vintage Year 2018 PPI in future rider proceedings is reasonable and appropriate, and should be approved.

EVIDENCE FOR FINDING AND CONCLUSION NO. 27

The evidence in support of this finding and conclusion can be found in the testimony of DEC witness Evans and supplemental testimony of DEC witness Duff and in the testimony of NC Justice Center and SACE witness Weiss.

Company witness Evans noted that Vintage 2016 of the Company's DSM and EE programs produced over 831 million kWh of energy savings and nearly 985 megawatts (MW) of capacity savings, which produced NPV avoided cost savings of over $471 million. He testified that during Vintage 2015, DEC's portfolio of DSM/EE programs was able to deliver energy and capacity savings that yielded avoided costs that were 139 percent of its target, while expending only 123 percent of targeted program costs.

Witness Evans testified that opt-outs by qualifying industrial and commercial customers have had a negative effect on the Company's overall non-residential impacts. For Vintage 2016, 3,534 eligible customer accounts opted out of participating in DEC's non-residential portfolio of EE programs, and 4,284 eligible customer accounts opted out of participating in the Company's non-residential DSM programs. While only six eligible customers that were opted out of the Vintage 2014 DSM Rider opted in to the Vintage 2015 DSM Rider, 72 eligible customers that were previously opted out chose to opt in to the Vintage 2016 DSM Rider.

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. 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.

SACE witness Weiss testified that the performance of DEC's DSM/EE portfolio had improved markedly and achieved record energy savings. However, she noted that the Company's energy savings forecast projects a decline in 2017 and that the Company continues to underestimate program performance by 30% or more annually, which could cause the Company to overstate its future capacity needs and plan for excess costs that will increase costs for customers. Witness Weiss pointed out the reliance of the Company's DSM/EE portfolio on lighting and behavioral programs. She noted that behavioral programs often have a low retention life, and lighting programs may struggle to keep up with market changes and penetration. Witness Weiss also discussed the amount of untapped market potential for cost-effective DSM/EE programs in DEC's territory, especially for vulnerable low-income communities and the non-residential sector. She noted with concern the increase in the percentage of non-residential customers electing to opt-out of the Company's DSM and EE programs. While acknowledging DEC's efforts to increase non-residential participation in DSM/EE programs, witness Weiss recommended additional improvements in the Company's DSM/EE efforts, including several recommendations that could encourage commercial and industrial customers to participate in DEC's DSM/EE programs. She also made specific recommendations regarding ways to expand and improve the Company's non-residential programs, as well as its residential programs, including low-income program opportunities. In particular, she recommended that:

(1) The Commission should direct the Company to continue collaborative working group discussions for low-income, multifamily, manufactured housing and industrial programs;

(2) The Company should use behavioral and lighting programs to encourage and improve cross-participation with other programs;

(3) The Commission should direct the Company to work with the Collaborative to develop values for the non-energy benefits (NEBs) associated with low-income programs and to evaluate new programs with this more robust evaluation framework moving forward; and

(4) The Company should adopt new programs based on best practices from around the country, including strategic energy management for industrial customers, comprehensive whole house retrofit programs, an enhanced multi-family affordable housing program, a multi-family new construction program, a manufactured housing program, and additional low-income residential EE programs.

In his rebuttal testimony, DEC witness Duff stated the Company's belief that the Collaborative meetings are the appropriate forum to receive feedback related to its portfolio of programs as well as ideas for potential new programs. He indicated that the Company agrees with witness Weiss' first recommendation that the Collaborative continue working group discussions for low-income, multifamily, manufactured housing and industrial programs. In regard to witness Weiss' second recommendation that the Company use its behavioral and lighting programs to improve cross-participation, witness Duff noted that in the past year at a Collaborative meeting, DEC discussed its ongoing efforts to cross-promote program participation. The Company is already actively attempting to cross-promote other programs through programs like My Home Energy Report. As to witness Weiss' third recommendation regarding the measurement, quantification, and inclusion of NEBs in the evaluation of low income programs in the future, witness Duff pointed out that the currently approved methodologies for evaluating the cost-effectiveness of DSM and EE programs are based on avoided costs associated with electricity (avoided energy, avoided capacity and avoided transmission and distribution), and that spending effort and money to measure and quantify NEBs that ultimately will not factor into the determination of a program's cost-effectiveness, does not seem prudent. He also indicated that the Sub 1032 Mechanism does not require low-income programs to pass cost-effectiveness screens; thus, it is unnecessary to quantify NEBs for these programs. Finally, he expressed concern about only quantifying NEBs for low-income programs, when these benefits would apply to other programs as well. As to witness Weiss' fourth recommendation that the Company adopt several new programs in its portfolio, witness Duff pointed out that no information or analysis had been provided by witness Weiss showing that the recommended programs would be cost-effective to offer for DEC.

The Commission believes that the Collaborative is the appropriate forum for consideration of the recommendations made by witness Weiss, to the extent DEC is not already implementing them, and as discussed below. Specifically, the Commission directs the Company to continue collaborative working group discussions for low-income, multifamily, manufactured housing and industrial programs, and include a narrative summary of these discussions in its next rider filing. The Collaborative should also discuss how DEC's behavioral and lighting programs can continue to be used to effectively encourage and improve cross-participation with other programs. The Collaborative should also discuss the inclusion in DEC's portfolio of any new programs based on best practices from around the country, including strategic energy management for industrial customers, comprehensive whole house retrofit programs, an enhanced multi-family affordable housing program, a multi-family new construction program, a manufactured housing program, and additional low-income residential EE programs. Parties proposing these programs should provide sufficient and applicable information for DEC to evaluate the cost-effectiveness of the programs. Finally, the Commission finds that the Collaborative should continue to discuss how to increase program participation and impacts with an emphasis on increasing the participation of opt-out eligible customers.

For the reasons stated in witness Duff's testimony, the Commission declines to require the Collaborative to develop values for the non-energy benefits associated with low-income or any other type of EE program at this time. In the rulemaking proceeding for Commission Rule R8-68 (Docket No. E-100, Sub 113), the Commission declined to modify the draft Rule R8-68(c)(2)(iv) regarding the cost-effectiveness tests and the inputs associated with those tests. SACE and other parties had argued in the rulemaking proceeding that consideration should be given to:

> "avoided resource benefits that lie outside the electric utility system, such as collateral reductions in non-electric energy use, water resources, or environmental impacts."

The Commission continues to uphold its consistent position that the costs and benefits associated with DSM and EE programs, and thus included in cost-effectiveness tests, should be those costs and benefits that are directly associated with the avoidance by a DSM or EE program of energy and capacity that the utility would otherwise have been required to produce with its fleet of generation resources. To the extent there is any causal relationship between the avoidance of energy and capacity resulting from a DSM or EE program and NEBs, the Commission believes that it is not easily or readily quantifiable. For the reasons stated, the Commission declines to require DEC or the Collaborative to develop values for the non-energy benefits associated with low-income or any other type of EE program.

EVIDENCE FOR FINDING AND CONCLUSION NO. 28

The evidence in support of this finding and conclusion can be found in the testimony of DEC witnesses Evans and Duff and Public Staff witnesses Hinton and Floyd, and the affidavit of Public Staff witness Maness.

Pursuant to Paragraph 78 of the Sub 1032 Mechanism, the terms and conditions of the Mechanism are to be reviewed every four years, unless otherwise ordered. Parties are to submit proposed changes at the time of their filings in the annual rider proceeding. The Sub 1032 Stipulation also provides that any party may request that the Commission initiate a review of the Mechanism at any time during the four-year period. The Sub 1032 Order provides that the Commission should initiate a review of the Sub 1032 Mechanism no later than July 1, 2017.

In his direct testimony, DEC witness Evans noted that DEC had been in discussions with the Public Staff regarding the way avoided costs are applied under the Mechanism, but that the Company was not proposing any changes to the Mechanism. He stated that the Company requested that the Mechanism remain in effect.

As discussed previously, Public Staff witness Maness testified that following the filing of DEC's application in this docket, the Public Staff and DEC reached a comprehensive agreement regarding the amount of the PPI for this proceeding, as well as proposed revisions to the Mechanism dealing with how applicable avoided costs will be determined on a going-forward basis. These recommended revisions are set out in Maness Exhibit II.

Revision to Mechanism Paragraph 69

Witness Maness stated that the first proposed revision was to Paragraph 69 of the Mechanism, which sets out how the avoided costs are determined for purposes of calculating the PPI. Under current Paragraph 69, avoided energy costs are derived from those calculated for the purposes of the Company's annual integrated resource plan (IRP) or resource plan update filings. Witness Maness noted that avoided capacity costs for PPI calculation are derived from the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases. As discussed previously, changes in the avoided costs used for PPI purposes occur only when certain ratchets have been tripped. Under the recommended revised language of Paragraph 69, 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 will be used to derive both the PPI-focused avoided capacity and energy costs (hereinafter, the "PURPA method") effective for Vintage Year 2019 and thereafter. However, Witness Maness explained that DEC and the Public Staff have also agreed that the Public Staff may propose further revisions to the Mechanism related to the use of the PURPA method of determining avoided costs should the methodologies adopted to determine avoided costs in the Biennial proceedings change in a manner that conflicts with their use in the DSM/EE context, including possibly the adoption of the "two-year refresh" proposal of the Company in Docket No. E-100, Sub 148. In regard to the two-year refresh, witness Hinton testified that two-year fixed avoided energy rates would add a degree of uncertainty and risk to the planning and development of new DSM/EE programs. Under cross-examination, witness Hinton noted that the current PURPA-based method looks at lifetime avoided energy costs over 10, 15, and 20 years, while a two-year refresh mechanism would not provide certainty as to the avoided energy costs beyond two-years, which would make difficult both the planning and evaluation of programs.

Public Staff witness Hinton explained that while the triggers in the current version of Paragraph 69 stabilized avoided costs and assisted the Company in its planning for its DSM/EE programs, they also had led to the use of potentially stale avoided costs that are not consistent with the expected energy reductions achieved by DEC's DSM/EE programs. Under cross examination, witness Hinton stated that the avoided cost rates which he referred to as "stale" were from 2012. If avoided costs change but the trigger thresholds were not reached, under or overstated avoided cost benefits and PPI incentives could result.

Witness Hinton testified that PURPA avoided energy costs are derived by taking the difference between one production cost run that includes an assumed 24x7, 100 megawatts (MW) of no-cost qualified facility (QF) energy and one without the 100 MW of QF energy. Under the proposed revision to Paragraph 69, the avoided energy costs would be derived by taking a similar differential approach, except the projected hourly load shapes and load reductions associated with the DSM/EE portfolio would be substituted for the 100 MW of 24x7 no-cost QF energy normally used for the purposes of deriving PURPA avoided energy costs. Witness Hinton concluded that under this approach, calculations of cost-effectiveness and the PPI would generally be based on the same avoided generation cost as the PURPA-based avoided energy rates.

Witness Hinton discussed the differences between using IRP-based avoided costs, as required under Paragraph 69 in its current form, and PURPA-based costs, as proposed in the revision to Paragraph 69. He explained that the IRP incorporates a System Optimizer capacity planning model that develops least cost integrated plans while satisfying reserve criteria, while PURPA proceedings incorporate the PROSYM model, an hourly chronological production cost model that incorporates more detailed generating unit characteristics such as the costs to start and shut down units, unit ramp rates, and unit minimum up and down times. A second significant difference in the two methodologies is that the cost of carbon emissions is included in IRP avoided costs and excluded from PURPA avoided costs. Under cross-examination, witness Hinton acknowledged that the PURPA-based avoided energy costs are generally lower that IRP-based avoided energy costs, as shown by the graph on page 7 of his testimony. Witness Hinton noted that a third difference is that the IRP is mainly a planning tool, while the PURPA proceeding is a where the cost inputs are more closely scrutinized. Finally, Witness Hinton advocated the use of PURPA-based avoided costs in the DSM/EE Mechanism because it would link the savings and financial incentives afforded the Company for its DSM/EE programs with the rates it pays QFs for avoided energy and avoided capacity. He stated his belief that the use of PURPA-based avoided energy and capacity costs would lead to better estimates of the costs avoided by the Company's DSM/EE programs and provide a more accurate view of the value of DSM and EE.

Revision to Mechanism Paragraph 19

Witness Maness testified that the second proposed revision to the Mechanism would specify the avoided costs to be used for purposes of program approval. The current Mechanism does not specify which avoided costs should be used, but the Company has typically used the avoided costs it used in the most recent annual DSM/EE Rider filing. He explained that DEC and the Public Staff have agreed to revise Mechanism Paragraph 19 to specifically require use of the "PURPA method" for the purpose of program approval filings. The specific Biennial Determination used for each program approval filing would be the one most recently approved by the Commission as of the date of the program approval filing.

Public Staff witness Floyd testified that the approach to cost-effectiveness for program approval should be consistent with the approach employed for ongoing cost-effectiveness evaluated in annual DSM/EE rider proceedings. He explained that the evaluation for program approval is typically based on a short-term projection of costs and participation, as there is greater uncertainty in the projections beyond five years. However, the evaluations incorporate the savings impacts of the measures over the life of the measure, which could be well beyond five years. Witness Floyd stated that the Public Staff believes that it is reasonable for the avoided costs used for a program approval to come from the most recent approved avoided cost proceeding.

Revision to Paragraph 23 and Addition of Paragraphs 23A-D

Witness Maness stated that the third revision to the Mechanism proposed by the Public Staff and DEC was 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 of the Mechanism, each year the Company files an analysis of the current cost-effectiveness of each of its DSM/EE programs as part of the DSM/EE Rider filing. Consistent with the revisions recommended for Paragraph 69, DEC and the Public Staff propose a new Paragraph 23A to require the use of the "PURPA method" for determining the avoided costs used in the determination of continued cost-effectiveness for each program. Also like Paragraph 69, Paragraph 23A specifies that the PPI-focused avoided capacity and energy costs will be derived from the avoided costs underlying 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. Witness Maness noted that this provision may also need to be revisited should the two-year refresh methodology be approved or enacted.

Witness Maness indicated that new Paragraphs 23B through 23D address the steps that will be taken if specific DSM/EE programs continue to produce Total Resource Cost Test results less than 1.00 for an extended period. Previously, provisions of this type have been handled solely on a case-by-case basis.

Witness Floyd explained that the proposed revisions to Paragraph 23 and the addition of Paragraphs 23A-D set out a process that provides timeframes for DEC to either modify or close programs that are not cost-effective. For any program that initially demonstrates a TRC of less than 1.00, the Company will 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. Witness Floyd testified that if a program demonstrates a prospective TRC of less than 1.00 in a third DSM/EE rider proceeding, the Company would terminate the program effective at the end of the year following the DSM/EE rider order, unless otherwise ordered by the Commission.

Reservation of Right to Address PPI Percentage in Later Proceeding

Finally, Witness Maness testified that the comprehensive agreement reached by the Public Staff and DEC allowed the Public Staff to reserve the right to potentially address any changes to the PPI percentage in a future proceeding. Pursuant to Paragraph 66 of the Mechanism, the PPI for each vintage year is calculated by multiplying the present value of the estimated net dollar savings associated with the DSM/EE portfolio installed in that vintage year by a factor of 11.5%. Witness Maness explained that this percentage should remain subject to periodic change to ensure that the bonus incentive it provides to the utility remains fair and reasonable. While the Public Staff is not proposing a change in the PPI percentage in this proceeding, DEC has agreed to recognize the Public Staff's reservation of the right to propose changes to the percentage in a future proceeding, perhaps in conjunction with the periodic review of Duke Energy Progress' DSM/EE Mechanism review, which is currently expected to occur in 2018 or 2019.

DEC witness Duff testified that the comprehensive agreement reached by DEC and the Public Staff improves upon the methodology used to calculate avoided costs under the Sub 1032 Mechanism and is good for customers because it will reduce the potential for the avoided costs used to assess program cost-effectiveness and establish DEC's PPI from becoming dated or stale, while still allowing DEC enough certainty to effectively plan its portfolio of programs. He noted that under the current Sub 1032 Mechanism, if the trigger thresholds were not hit, avoided cost rates could potentially remain unchanged for years. Under the proposed modifications to the Mechanism, DSM and EE programs will be evaluated for cost-effectiveness using Commission-approved avoided cost rates that are generally updated every two years. Another benefit to customers is that it aligns the avoided energy and avoided capacity costs used for DSM/EE with those approved in the Company's biennial avoided cost proceeding, avoiding a potential mismatch that could undermine the validity of the cost-effectiveness evaluation. Witness Duff also pointed out that the proposed revisions created a clear protocol for the Company to address programs that are struggling to maintain cost-effectiveness, giving the Company time to manage the program and improve its cost-effectiveness, if possible, while also creating a specific timeline to ensure that a non-cost-effective program that does not have the potential to improve does not continue to unnecessarily add costs to the DSM/EE rider. Witness Duff concluded that the agreement is in the public interest and should be accepted by the Commission as a fair and reasonable resolution of the issues in this proceeding. NCSEA in its post-hearing brief, stated that it was supportive of using avoided costs rates that are as recent as practicable, and as such does not object to the settlement reach between DEC and the Public Staff.

No parties other than the Public Staff and DEC proposed revisions to the Sub 1032 Mechanism. The Commission notes that on July 18, 2017, SACE, the South Carolina Coastal Conservation League, the Sierra Club, and the Natural Resources Defense Council, parties to Sub 1032 Agreement filed a letter in Docket No. E-7, Sub 1032, informing the Commission that they do not believe a review of the Mechanism is necessary at this time. On July 19, 2017, the Commission issued an Order in Docket No. E-7, Sub 1032, requesting comments on whether a review of the Mechanism is necessary at this time and any proposed revisions.

As witness Duff testified at the hearing, the Public Staff and DEC are not proposing revisions to the Sub 1032 Stipulation, but rather are proposing changes to the Sub 1032 Mechanism. In Paragraph 78, the Sub 1032 Stipulation expressly provides that the Company or any other party may file any proposals for revisions to the Sub 1032 Mechanism along with their testimony in the annual DSM/EE rider proceeding. In accordance with this provision, the Public Staff filed proposed revisions along with witness Maness's testimony in this rider proceeding. DEC then filed supplemental testimony from witness Duff supporting these revisions. While cross-examination of DEC's and the Public Staff's witnesses during the hearing seemed to indicate that SACE and NCSEA thought that they, as Stipulating Parties, should have been included in discussions of the proposed revisions to the Sub 1032 Mechanism,[1] there is nothing in the Sub 1032 Mechanism or Sub 1032 Order that requires that the Stipulating Parties discuss or jointly propose potential changes to the Sub 1032 Mechanism. Indeed, the Commission's Sub 1032 Order provides for "continuing review of the Mechanism for reasonableness as necessary and appropriate," and the Sub 1032 Stipulation itself provides that "a Stipulating Party" (as opposed to all "Stipulating Parties") may request that the Commission review and revise the terms of the Sub 1032 Mechanism. This is also consistent with the process by which the EM&V Agreement,

[1] There is no evidence in the record that NCSEA or SACE have any substantive issues with the proposed revisions. Indeed, in its post-hearing Brief NCSEA states that it "does not take issue with the settlement reached by DEC and the Public Staff." NCSEA's Post-Hearing Brief, at p. 7.

Flexibility Guidelines, and Found Revenues "Decision Tree"[1] were proposed and adopted. Accordingly, the Commission finds and concludes that the method by which the Public Staff and DEC proposed revisions to the Sub 1032 Mechanism is appropriate under the Sub 1032 Stipulation, the Sub 1032 Mechanism and the Sub 1032 Order. Nonetheless, as cited by NCSEA in its post-hearing Brief, the Commission has opined that "it is preferable when manageable for all parties to have an opportunity to participate in the settlement negotiations." Order Declining to Adopt Proposed Settlement Rules, Docket No. M-100, Sub 145, at p. 13 (March 1, 2013).

The Commission further concludes that the revisions to the Sub 1032 Mechanism proposed by the Public Staff and DEC are appropriate and in the public interest, and should be adopted. First, the revision to Paragraph 69 removes any ambiguity regarding the proper avoided costs to be used for calculating the PPI. The Commission finds that the revision to Paragraph 69 better links the savings and financial incentives for DEC's DSM/EE programs with the rates it pays QFs for avoided energy and avoided capacity, and provides for regular updating to prevent stale or outdated rates. Further, the Commission finds that the revision to Paragraph 19, which specifies the avoided costs to be used in calculating cost-effectiveness in program approvals, is appropriate and should be adopted. Likewise, the revisions to Paragraph 23 and the proposed Paragraphs 23A-D are appropriate for specifying the avoided costs to be used in calculating ongoing cost-effectiveness, as well as setting out a procedure for modification or closure of programs that are no longer cost-effective. Finally, the Commission recognizes the right of any party to propose further modifications to the Mechanism in future proceedings, including the Public Staff's right to revisit the PPI percentage. Therefore, the Commission adopts the revisions to the Mechanism as set out in Maness Exhibit II to be effective January 1, 2018.

IT IS, THEREFORE, ORDERED as follows:

1. That 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 Supplemental Exhibits of Robert P. Evans, and the resulting billing factors as set forth in Supplemental Miller Exhibit 1, to go into effect for the rate period January 1, 2018, through December 31, 2018, subject to appropriate true-ups in future cost recovery proceedings consistent with the Sub 1032 Order and other relevant orders of the Commission.

2. That DEC shall work with the Public Staff to prepare a proposed Notice to Customers of the rate changes approved herein. Within 30 days from the date of this Order, the Company shall file said notice and the proposed time for service of such notice on customers for Commission approval.

[1] DEC, the Public Staff, SACE, SELC, EDF and NRDC were all parties to the Sub 831 Settlement, yet only a subset of these parties proposed each of these changes to the Sub 831 Mechanism: DEC, the Public Staff and SACE proposed the EM&V Agreement; DEC, the Public Staff and SACE proposed the Flexibility Guidelines; and DEC and the Public Staff proposed the Found Revenues "Decision Tree."

3. That the Appliance Recycling program should be canceled as of December 31, 2017, and the PowerShare Call Option as of January 31, 2018, and the Company should not incur further expenses for either program, unless the Company, within 60 days of this Order, provides sufficient justification for continuing either program.

4. That in its next rider application, DEC should address the continuing cost-effectiveness of the Non-Residential Smart $aver Performance Incentive Program and the Residential HVAC EE Program, and if either is not cost-effective, provide details of plans to modify or close the program.

5. That the EM&V reports for the Multi-Family Energy Efficiency Program (Evans Exhibit B), the Smart $aver Prescriptive Incentive Program (Evans Exhibit F), and the EM&V Report for the Small Business Energy Saver Program (Evans Exhibit J) should be revised as discussed by Public Staff witness Floyd and refiled in the next rider.

6. That the Company should, when feasible and not cost prohibitive, incorporate the recommendations made by Public Staff witness Floyd regarding EM&V into future EM&V reports filed with the Commission in subsequent DSM/EE rider proceedings.

7. That DEC should leverage the Collaborative to: (a) continue collaborative working group discussions for low-income, multifamily, manufactured housing and industrial programs, and include a narrative of these discussions in its next rider filing; (b) discuss how DEC's behavioral and lighting programs can be used to encourage and improve cross-participation with other programs; (c) discuss the potential inclusion in DEC's portfolio of any new programs based on best practices from around the country, including strategic energy management for industrial customers, comprehensive whole house retrofit programs, an enhanced multi-family affordable housing program, a multi-family new construction program, a manufactured housing program, and additional low-income residential EE programs, with parties proposing these programs providing sufficient and applicable information for DEC to evaluate the cost-effectiveness of the programs; and (d) continue to discuss how to increase program participation and impacts with an emphasis on increasing the participation of opt-out eligible customers as discussed in the testimony of NC Justice Center and SACE witness Weiss.

8. That the Commission hereby approves and adopts the revisions to the Sub 1032 Mechanism as set out in Maness Exhibit II to be effective January 1, 2018.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of August, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

Former Commissioner Don M. Bailey and present Commissioner Daniel G. Clodfelter did not participate in the issuance of this Order.

DOCKET NO. E-7, SUB 1131

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC,	)	
for Approval of Renewable Energy and Energy	)	ORDER APPROVING REPS AND
Efficiency Portfolio Standard Cost Recovery	)	REPS EMF RIDERS AND
Rider Pursuant to G.S. 62-133.8 and	)	2016 REPS COMPLIANCE REPORT
Commission Rule R8-67	)	

HEARD: Tuesday, June 6, 2017 at 9:30 a.m. in the Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, James G. Patterson and Lyons Gray

APPEARANCES:

For Duke Energy Carolinas, LLC:

Kendrick C. Fentress, Associate General Counsel, Duke Energy Corporation, 410 South Wilmington Street, NCRH 20/P.O. Box 2551, Raleigh, North Carolina 27601

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 & Currin, LLC, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

For North Carolina Sustainable Energy Association:

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

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, NC, 27699

Robert B. Josey, Jr., Staff Attorney, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, NC, 27699

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

BY THE COMMISSION: On March 8, 2017, Duke Energy Carolinas, LLC (DEC or the Company) filed its 2016 REPS Compliance Report and application seeking an adjustment to its North Carolina retail rates and charges pursuant to G.S. 62-133.8(h) and Commission Rule R8-67, which require the Commission to conduct an annual proceeding for the purpose of determining whether a rider should be established to permit the recovery of the incremental costs incurred to comply with the requirements of the Renewable Energy and Energy Efficiency Portfolio Standard (REPS), G.S. 62-133.8(b), (d), (e) and (f), and to true up any under-recovery or over-recovery of compliance costs. DEC's application was accompanied by the testimony and exhibits of Travis Payne, Business Development Manager, and Veronica I. Williams, Rates and Regulatory Strategy Manager. In its application and pre-filed testimony, DEC sought approval of its proposed REPS Rider, which incorporated the Company's proposed adjustments to its North Carolina retail rates.

On March 22, 2017, 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) 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 G.S. 62-15(d) and Commission Rule R1-19(e).

On April 18, 2017, DEC filed supplemental testimony and revised exhibits of witnesses Payne and Williams.

On April 27, 2017, the Commission issued an Order Requiring Additional Public Notice.

On May 19, 2017, DEC filed additional supplemental testimony and revised exhibits of witnesses Payne and Williams.

On May 22, 2017, the Public Staff filed the affidavits of Michelle Boswell and Jay B. Lucas.

On June 1, 2017 and June 2, 2017, DEC filed the required affidavits of publication for the initial and the additional notice of hearing in accordance with the Commission's orders requiring publication of notices.

This matter came on for hearing as scheduled on June 6, 2017. DEC presented the testimony and exhibits of witness Payne and witness Williams, and the Public Staff presented the affidavits of witness Boswell and witness Lucas. All pre-filed testimony, exhibits, and affidavits from the DEC and Public Staff witnesses were received into evidence.

In addition to the foregoing, there were other motions, orders, and filings not specifically mentioned, which are matters of record.

Based upon the foregoing, the testimony, exhibits, and affidavits introduced 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. 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 also an electric power supplier as defined in G.S. 62-133.8(a)(3). DEC is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.8 and Commission Rule R8-67.

2. For calendar year 2016, the Company is required to meet at least 6% 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 (EE) measures. Also in 2016, energy in the amount of at least 0.14% of the previous year's total electric power sold by DEC to its North Carolina retail customers must be supplied by solar energy resources.

3. Beginning in 2012, 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, 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 North Carolina retail sales. In its Order Modifying the Swine Waste Set-Aside Requirement and Providing Other Relief, issued on October 17, 2016, in Docket No. E-100, Sub 113 (October 17 Order), the Commission delayed for one year the swine waste set-aside requirement, directing that the swine waste set-aside requirements will commence in 2017. The Commission also modified the 2016 poultry waste set-aside requirement to remain at the same level as the 2015 requirement and delayed by one year the scheduled increases in the requirement.

4. G.S. 62-133.8(h) authorizes an electric power supplier to recover the "incremental costs" of compliance with the REPS requirements through an annual REPS rider. The "incremental costs," as defined in 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.

5. Under Commission Rule R8-67(e), the total costs reasonably and prudently incurred during the test period to purchase unbundled renewable energy certificates (RECs) constitute incremental costs. The projected costs to purchase such RECs during the billing period constitute forecasted incremental costs.

6. DEC has agreed to provide compliance services, including the procurement of RECs, to the following electric power suppliers, pursuant to G.S. 62 133.8(c)(2)(e): Blue Ridge Electric Membership Corporation (EMC), the City of Concord, the Town of Dallas, the Town of

Forest City, the Town of Highlands, the City of Kings Mountain and Rutherford EMC (collectively the Wholesale Customers).

7. DEC has complied with the 2016 solar set-aside requirements, for itself and the Wholesale Customers for which DEC is providing compliance services, through the procurement or generation of 85,835 RECs from solar electric facilities and metered solar thermal energy facilities. DEC has also complied with the 2016 poultry waste set-aside requirements, for itself and the Wholesale Customers for which DEC is providing compliance services, through the procurement or generation of 73,444 RECs from poultry waste-to-energy facilities, along with 4,000 poultry waste set-asides RECs produced from utilizing 2,000 SB 886 RECs.

8. DEC and the seven electric power suppliers for which DEC is providing compliance services met the 2016 REPS requirements, including the set-aside requirements as modified by the Commission's Orders issued in Docket No. E-100, Sub 113.

9. DEC is uncertain whether or not it will be able to comply with the increased 2017 swine waste resource requirement or the increased 2017 poultry waste resource requirement at this time.

10. For purposes of DEC's annual rider pursuant to G. S. 62-133.8(h), the test period and the billing period for this proceeding are, respectively, the calendar year 2016 and the 12-month period beginning September 1, 2017, and ending August 31, 2018.

11. The research activities incurred 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 in G.S. 62-133.8(h)(1)(b).

12. For purposes of establishing the REPS experience modification factor (EMF) rider in this proceeding, DEC's incremental costs for REPS compliance during the test period were $22,225,765, including the costs incurred for its Wholesale Customers, and these costs were reasonably and prudently incurred. The Company's projected incremental costs for REPS compliance for the billing period total $35,069,965, including the costs incurred for its Wholesale Customers.

13. DEC's sales of RECs reviewed in this proceeding are appropriate, and DEC has accounted for them correctly.

14. DEC appropriately calculated its avoided costs and incremental REPS compliance costs for the test period and/or billing period, including those avoided and incremental costs specifically related both to the Company's Solar Photovoltaic Distributed Generation (Solar DG) 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 Order on Reconsideration, issued May 8, 2009, in Docket No. E-7, Sub 856; (2) Order Transferring Certificate of Public Convenience and Necessity, issued May 16, 2016, in Docket No. E-7, Sub 1079, and (3) Order Transferring Certificate of Public Convenience and Necessity, issued May 16, 2016 in Docket No. E-7, Sub 1098.

15. It is appropriate to approve DEC's request to recover other incremental costs pursuant to G.S. 62-133.8(h)(1)(b) as incremental costs reasonably and prudently incurred to comply with the REPS requirements.

16. DEC complied with Commission's Order in Docket No. E-7, Sub 1106 (Sub 1106) by filing in this proceeding a worksheet detailing its interconnection cost allocation process related to labor and other costs. It is appropriate to require DEC to continue to file a worksheet explaining the discrete costs that DEC includes as "other incremental costs" in all future REPS Rider proceedings.

17. DEC's test period REPS expense (over-) or under-collections were an (over-) collection, including interest, of $(1,984,079) for the residential class, $(1,608,803) for the general service class, and $(133,106) for the industrial class, excluding the North Carolina regulatory fee (regulatory fee).

18. DEC's North Carolina retail prospective billing period expenses for use in this proceeding are $18,785,900, $12,303,695 and $1,019,087, for the residential, general service, and industrial classes, respectively, excluding regulatory fee.

19. The appropriate monthly REPS EMF riders per customer account, excluding regulatory fee, to be credited to customers during the billing period are $(0.10) for residential accounts, $(0.58) for general service accounts, and $(2.39) for industrial accounts.

20. The appropriate monthly prospective REPS riders per customer account, excluding regulatory fee, to be collected during the billing period are $0.93 for residential accounts, $4.28 for general service accounts, and $17.52 for industrial accounts.

21. The combined monthly REPS and REPS EMF rider charges per customer account, excluding the regulatory fee, to be collected during the billing period are $0.83 for residential accounts, $3.70 for general service accounts, and $15.13 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 $0.83 for residential accounts, $3.71 for general service accounts, and $15.15 for industrial accounts.

22. DEC's REPS incremental cost rider, including the regulatory fee, to be charged to each customer account for the billing period is within the annual cost cap established for each class in G.S. 62-133.8(h)(4).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-6

These findings of fact are essentially informational, jurisdictional and procedural in nature and are not contested.

Subsection 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 EE resources which are listed in G.S. 62-133.8(b)(2) as follows: (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 produced from in-State or out-of-state new renewable energy facilities; (f) using electric power that is supplied by a new renewable energy facility or saved due to the implementation of an EE 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 2016, an electric public utility in the state of North Carolina must meet a total REPS requirement equal to 6% of its previous year's North Carolina retail electric sales by a combination of these measures.

Subsection 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 2016 is 0.14%.

Subsections 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. 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 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. 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 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 Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief issued October 17, 2016, in Docket No. E-100, Sub 113, the Commission further delayed for one year the swine waste set-aside requirement; accordingly, the swine waste set-aside requirements will commence in compliance year 2017. The Commission also modified the 2016 poultry waste set-aside requirement to remain at the same level as the 2015 requirement (an aggregate of 170,000 megawatt -hours of electricity generated via poultry waste divided amongst the electric power suppliers), and delayed by one year the scheduled increases in the requirement (the requirement is scheduled to increase to 700,000 megawatt-hours in the aggregate for all electric power suppliers).

Subsection 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 G.S. 62-133.8 though an annual rider. 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 requirement that are in excess of the electric power supplier's avoided costs other than those costs recovered pursuant to 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."

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."

In its 2015 compliance report, DEC stated that it provided renewable energy resources and compliance reporting services for Blue Ridge EMC, the City of Concord, the Town of Dallas, the Town of Forest City, the Town of Highlands, the City of Kings Mountain, and Rutherford EMC, as allowed by G.S. 62-133.8(c)(2)(e).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-9

The evidence supporting these findings of fact is found in the testimony and exhibits of DEC witnesses Payne and Williams and in the affidavit of Public Staff witness Lucas. In addition, the Commission takes judicial notice of the information contained in NC-RETS.

DEC witness Payne testified that DEC submitted its 2016 REPS compliance report as Payne Exhibit No. 1, as revised in DEC's filing on of April 18, 2017 in this docket, and that this report contained all the information required by Commission Rule R8-67(c) in the aggregate for DEC and the Wholesale Customers for which DEC has contracted to provide REPS compliance services.

Witness Payne further testified that DEC has submitted for retirement 3,674,466 RECs to meet its total requirement for 2016. He defined the "total requirement" as DEC's overall REPS requirement. Within this total, the Company submitted for retirement 85,835 RECs to meet the solar set-aside requirement, and 73,444 RECs, along with 2,000 SB 886 RECs (which count as 4,000 poultry waste RECs), to meet the poultry waste set-aside requirement. Witness Payne testified that the billing period for this Application covers two separate compliance reporting periods with different requirements for each period. In 2017, the Company estimates that it will be required to submit for retirement 3,667,343 RECs to meet the requirements of G.S. 62-133.8(b), or its total requirement. Within this total, the Company is also required to retire the following to comply with the requirements of G.S. 62-133.8(d), (e) and (f), respectively: 85,576 solar RECs, 42,790 swine waste RECs, and 318,866 poultry waste RECs. DEC estimates that its 2018 total requirement will be 6,111,027 RECs to be submitted for retirement. Within this total estimate, the Company projects that it will be required to retire approximately 122,224 solar RECs, 42,782 swine waste RECs, and 409,971 poultry waste RECs to meet the requirements set out in G. S. 62-133.8(d), (e), and (f) respectively.

Witness Payne testified that DEC has met its solar set-aside requirement for 2016 by procuring and producing 85,835 solar RECs and that, 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 and the Sub-Accounts of the Wholesale Customers.

Witness Payne further testified that the Company complied with its General Requirement for 2016. Pursuant to the NC-RETS Operating Procedures, the Company submitted for retirement 3,515,187 RECs to meet the General Requirement. Specifically, the RECs to be used for 2016 compliance have been 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.

Public Staff witness Lucas recommended that the Commission approve DEC's 2016 REPS compliance report. Specifically, he testified that for 2016 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 6% of its 2015 North Carolina retail electricity sales and the retail sales of the Wholesale Customers. Witness Lucas stated that additionally, DEC needed to pursue retirement of sufficient solar RECs to match 0.14% of retail sales in 2015 for itself and the Wholesale Customers, and of its pro-rata share of the 170,000 poultry waste RECs required by G. S. 62-133.8(f). The number of poultry waste RECs was determined by the Commission in its October 17, 2016 Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief. The Order also delayed the swine waste requirement, under G.S. 62-133.8(e), for an additional year.

No party disputed that DEC had fully complied with the applicable REPS requirements, or argued that DEC's 2016 REPS compliance report should not be approved.

Based upon the foregoing and the entire record herein, the Commission finds that DEC and the Wholesale Customers have complied with the REPS requirements for 2016, including the set-aside requirements, as modified by the Commission's most recent Order modifying and delaying the poultry and swine waste set-aside requirements issued in Docket No. E-100, Sub 113. Therefore, the Commission concludes that DEC's 2016 REPS compliance report should be approved, and that the RECs and EECs in the related NC-RETS compliance sub-accounts should be permanently retired. Finally, the Commission finds, as witness Payne testified, that at this time DEC is uncertain whether it will be able to comply with the poultry waste and swine waste set-aside requirements for 2017 and that the Company is committed to satisfying these requirements by continuing to reasonably and prudently pursue procurement of these resources.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

This finding of fact is essentially informational and procedural in nature, 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 for DEC in Rule R8-55(c) to be the 12 months ending December 31 of each year. Commission Rule R8-67(e)(5) provides that "[t]he 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." Commission Rule R8-67(e)(4) further provides that the REPS and REPS EMF riders shall be in effect for a fixed period, which "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." In its current fuel charge adjustment proceeding, in Docket No. E-7, Sub 1104, and in this proceeding, DEC proposed that its rate adjustments take effect on September 1, 2016, and remain in effect for a 12-month period. This period is referred to as the "billing period."

The test period and the billing period proposed by DEC were not challenged by any party. The Commission concludes that the test period and billing period appropriate for this proceeding are the calendar year 2016 and the twelve months ending August 31, 2018, respectively.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding of fact is found in the testimony of DEC witnesses Payne and Williams.

Witness Payne sponsored Confidential Payne Exhibit No. 2 as an exhibit to his testimony, wherein he identified the "Research" and "Other Incremental Costs" that the Company has incurred or projects to incur in association with REPS compliance. With respect to research costs, Revised Williams Exhibit No. 1 shows that the research costs are under the $1-million per year cap established in G.S. 62-133.8(h)(1)(b). Consistent with the Commission's orders in past REPS Rider proceedings, witness Payne provided testimony and exhibits addressing the results and status of various studies, the cost of which DEC is including for recovery in its incremental REPS cost for the calendar year 2016 test period. Specifically, his testimony provided detailed information on the following research and development costs incurred by the Company associated with the REPS riders:

- Loyd Ray Farms – The Company partnered with Duke University to develop a pilot-scale, sixty-five kilowatt (kW) swine waste-to-energy facility, which initiated operation and began producing renewable energy in 2011. Payne Exhibit No. 5 summarized the project's progress through December 31, 2016.

- Closed Loop Biomass – The Company continues to support a closed-loop biomass research project to better understand yield potential for various woody crops, including Loblolly Pine, Hybrid Poplar, Hybrid Aspen, Sweetgum, Willow and Cottonwood trees. Crop production levels may take several years to reach full maturity. American Forest Management provides project management support and periodic updates to the Company, as seen in Payne Exhibit No. 6.

- Operational Impacts of Solar at Various Penetration Levels – In 2015 and continuing into 2016, DEC commissioned Pacific Northwest National Laboratory, Power Costs Inc., EnerMod LLC, and Quanta Technology to perform a comprehensive and detailed generation, transmission, and distribution impact/integration study. In this work, the intent was to perform an integrated study of the generation and transmission system, modeling the generating fleet and its connections to the transmission system directly, along with a partially decoupled modeling of the distribution system and the associated impacts of solar. In the generation and transmission study, the modeling of photovoltaic (PV) resource data attempted to account for geographical patterns of actual PV installations that were in service and those in the interconnection queue. The distribution study used a sampled modeling approach in order to estimate the impacts to the thousands of Duke Energy's distribution circuits. This study for the Carolinas was completed in 2016, and the confidential executive summary is shown in Payne Exhibit No. 7. Portions of the summary pertaining to Florida operations have been redacted.

- Distributed Energy Resource – Islanding Detection and Control (DER-IDC) – There is growing consensus in the industry that as DER grows in its penetration levels, the effectiveness of anti-islanding schemes currently in use in inverters and protective relaying schemes will degrade, and that future schemes will likely need to involve some sort of communications. This sentiment has been discussed multiple times at recent Institute for Electrical and Electronics Engineers working group meetings, at which the Company is an active participant. To that end, DEC engaged in an initial study to look at wide-scale communications methods that could be used to solve this growing concern. DEC contracted with Northern Plains Power Technologies (NPPT), an engineering consulting firm, to study data collected from Duke Energy facilities and research potential algorithms and communications methods that would be effective for communications based Islanding Detection and Control methods. In 2016, NPPT helped the Company thoroughly evaluate the feasibility of the first desired communication technology called eLoran. There are further phases planned for this project in 2017. As part of the data collection effort, protection/control/monitoring equipment was purchased and installed at the Company's Marshall, McAlpine, and Rankin R&D sites. This equipment included several satellite clocks and a real-time automation controller. The Company also contracted with Xtensible Solutions, an information technology and service company, to develop the use-case requirements and data model for microgrids. The results of this feasibility study can be found in Payne Confidential Exhibit Nos. 8 a-d. In addition, DEC contracted with Green Energy Corp, which developed the data translator for local access and filtering of streaming phasor measurement unit at distribution measurement equipment back to a phaser data concentrator in the back-office. A status report for this project can be found in Payne Exhibit No. 9.

- Rankin Battery/Aquion Energy – The Company is continuing to advance its knowledge of energy storage. One aspect of energy storage is battery chemistry; specific chemistries are suited to specific use cases. For example, one type of chemistry might be well-suited to "energy battery" energy-shifting applications (charging over many hours in one part of the day and discharging for many hours in another part of the day), whereas other chemistries might work better for "power battery" applications, like being co-located with PV facilities to mitigate intermittent output. To this end, DEC has installed an energy storage facility at its Rankin substation that will utilize a hybrid arrangement that should allow use as both an energy battery and a power battery. DEC successfully installed and commissioned this energy storage system in 2016. Confidential control algorithms were developed for several use cases, and testing of these would begin in 2017.

- ELECT, P.C. – The Company asked the consulting firm of ELECT, P.C. to analyze a fault event that had occurred twice in a two-week period at a large solar generating facility and negatively impacted a nearby industrial customer. Since the Company has limited experience with fault events at solar generating facilities, this analysis confirmed and substantiated other data from Company facilities and helped the Company better understand the nature of fault events at such facilities. The results of this analysis can be found in Payne Confidential Exhibit No. 10.

- Rocky Mountain Institute (RMI) – The Company participates in eLab, a forum sponsored by RMI, composed of a number of North Carolina and nationally based entities, and organized to overcome barriers to economic deployment of distributed energy resources in the U.S. electric sector. Specifically, Duke seeks to gauge customer desires related to distributed resources and provide ideas of potential long-term solutions for distributed energy resources and microgrids.

- Electric Power Research Institute (EPR) – In 2016, the Company subscribed to the following EPRI programs, the costs for which were recovered via the REPS rider: Program 193 – Renewable Generation, which includes Program PS193C – Solar. The Company also supported an EPRI Supplemental Project, P170B, which studied demand response as a flexible resource. EPRI designates such study results as proprietary or as trade secrets and licenses such results to EPRI members, including DEC. As such, DEC may not disclose the information publicly. Non-members may access these studies for a fee. Information regarding access to this information can be found at http://www.epri.com/Pages/Default.aspx. In addition, DEC participated in the EPRI Flexible Demand Response (DR) Project, designed to explore the capability and value of employing DR as a flexible resource in system operations, by leveraging existing technology and infrastructure investments.

- NC State University's Future Renewable Electric Energy Delivery and Management (FREEDM) Systems Center – DEC supports NC State's FREEDM Center through annual membership dues. The FREEDM partnership provides DEC with the ability to influence and focus research on materials, technology, and products that will enable the utility industry to transform the electric grid into a two-way power flow system supporting distributed generation.

- PV Farm Inspection – With an increasing number of utility-scale solar generating facilities connected to the Company's distribution network, it is important to prevent or limit degradation of power quality and/or reliability in service to other utility customers. In April and May 2016, the Company contracted Enerco Energy Services, an asset management services provider, to inspect randomly selected PV farms for the construction quality and code compliance of the medium voltage equipment, including but not limited to overhead distribution lines, underground cable terminations, transformers and transformer connections. The results of these inspections can be found in Payne Exhibit No. 11.

- Mini-DVAR Project – In 2016, the Company started a project to investigate a new technology manufactured by American Superconductor Corporation which makes a device called Mini-DVAR. This device can potentially be used for voltage stability/VAR support for renewable energy applications such as voltage compliance, grid reliability, efficiency, energy savings and grid integration of distributed PV. The project also included engineering design of a protection scheme with Schweitzer Engineering Laboratories, and the procurement of switch gear from ABB. This project will continue in 2017.

- Marshall Solar Site Algorithm – In 2016, the Company worked with University of North Carolina at Charlotte on a project to update the control algorithms that were designed and implemented at Marshall Solar site, with the purpose of improving the cost benefit. The results of this project can be found in Payne Confidential Exhibit No. 12.

- Solar Farm Site Visit Safety Equipment – The Company sees increasing need for sending engineering professionals to the field to support customers. The Company procured safety equipment (fire retardant clothing) for the employees who occasionally need to visit solar farms.

- Other Resources and Subscriptions – The Company subscribes to various renewable energy news and trade publications to gain access to market analyses, including price and supply/demand trends for renewable energy. Such publications are generally proprietary and provided to the Company under confidentiality licenses and, as such, the Company may not disclose the information publicly. Interested parties can obtain copies of such reports and analyses for a fee. The Company subscribes to or has purchased services from Bloomberg New Energy Finance and IHS Global.

By its post-hearing brief and partial proposed order, NCSEA argues that the costs incurred for the studies of operational impacts of solar at various penetration levels and for solar farm site visit safety equipment are not recoverable under G.S. 62-133.8(h)(1)(b). The specific amounts that DEC seeks to recover for these "research costs" are detailed in 2nd Revised Payne Exhibit No. 3, which was filed under seal as confidential trade secret information. Likewise, DEC filed the results of these studies under seal. After NCSEA raised these questions on cross examination, no other party disputed that the costs incurred related to these studies are recoverable as incremental costs pursuant to G.S. 62-133.8(h)(1)(b), nor argued that incurring these was unreasonable and imprudent. No party argued that DEC's requested costs are in excess of the statutory limit of one million dollars per year.

The Commission carefully considered NCSEA's arguments, but is not persuaded that these costs are outside the scope of "incremental costs" recoverable as costs reasonably and prudently incurred to "fund research that encourages the development of renewable energy, energy efficiency, or improved air quality." G.S. 62-133.8(h)(1)(b). DEC witness Payne testified that the studies are used by various departments within the Company, although he could not explain how one specific department, DEC's system operators, might have used the studies. Nonetheless, witness Payne testified that he assumed that these studies are being used by Company employees that are planning with regard to the renewable resources addressed by the studies. Witness Payne's testimony and the Commission's review of the study results establishes a logical connection between the study results and the encouragement of the development of renewable energy and improved air quality because the study informs DEC's ability to integrate renewable energy resources, and specifically solar PV, into its electric system. The logical inference the Commission draws from this evidence is that successfully integrating solar PV into DEC's electric system will encourage development of solar PV, and that this, in turn, displaces electric power generated from fossil-fuel burning electric generation units and encourages improved air quality. Likewise, the Commission draws the logical inference that safety equipment for employees who visit solar PV facilities encourages the development of renewable energy because it supports safely integrating these resources into DEC's electric system. The Commission, therefore, concludes that the research costs NCSEA disputes are sufficiently related to encouraging the development of renewable energy and improved air quality as required by G.S. 62-133.8(h)(1)(b), and, as such, DEC should be allowed to recover these costs through the REPS EMF rider.

Based upon the foregoing, the Commission finds that the research activities described by DEC witness Payne are incremental costs reasonably and prudently incurred by DEC to fund research as allowed by G.S. 62-133.8(h)(1)(b), and that these costs totaling $736,977 in the EMF period are within the $1-million annual limit provided in that statute. The Commission further concludes that, with the addition of the information filed in the testimony and exhibits of DEC's witnesses, the Company has complied with the requirement to file study results or information about how to access study results for research conducted with REPS rider funds. The Company shall continue to include that information in future REPS rider applications.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-15

The evidence supporting these findings of fact is found in the testimony and exhibits of DEC witnesses Payne and Williams and in the affidavits of Public Staff witnesses Boswell and Lucas.

DEC witness Williams testified regarding the calculation of DEC's avoided costs and its incremental costs of compliance with its REPS requirements, based on incurred and projected costs provided by witness Payne. Consistent with Commission Rule R8-67(e)(2), which provides that the cost of an unbundled REC is an incremental cost with no avoided cost component, witness Williams included in incremental costs the total amount of costs incurred during the test period for unbundled REC purchases. Revised Williams Exhibit No. 1 identified total retail and wholesale incremental costs incurred during the test period as $22,225,765, and projected incremental costs for the billing period as $35,069,965. Further, the projected costs of unbundled REC purchases discussed by witness Payne during the billing period are included as estimated billing period incremental costs. Company witness Payne additionally testified the company sold poultry RECs during the test period to other electric suppliers in North Carolina to enable the entire state to comply with the poultry waste set-aside requirements. He stated that the proceeds from the sale of these RECs were credited back to DEC's customers in 2016. DEC witness Payne confirmed that the sales of poultry waste RECs did not negatively impact DEC's compliance.

Witness Williams testified that, consistent with Commission Rule R8-67(a)(2), DEC's approved avoided cost rates are set forth in Rate Schedule PP-N, Purchased Power Non-Hydroelectric, and Rate Schedule PP-H, Purchased Power Hydroelectric (collectively, Schedule PP). For executed purchased power agreements, where the price of the REC and energy are bundled, the Company used annualized combined capacity and energy rates shown on the Company's Exhibit No. 3, filed in Docket No. E-100, Sub 106; Exhibit No. 3 in Docket No. E-100, Sub 117; Exhibit No. 3 in Docket No. E-100, Sub 127; or Exhibit No. 3 in Docket No. E-100, Sub 136 (depending on the effective date of the executed contract). For those purchased power agreements with terms that did not correspond with the durational terms for which rates were established in the avoided cost proceeding (i.e., two, five, ten, or fifteen-year durations), DEC computed avoided cost rates for the particular term of the purchased power agreements using the same inputs and methodology used for the Schedule PP rates approved in Docket No. E-100, Subs 106, 117, 127, or 136, as appropriate. Witness Williams also stated that the estimated avoided cost components of energy and REC purchased power agreements effective during the prospective billing period were calculated in the same manner.

With respect to DEC's Solar DG program, witness Williams testified that DEC determined the avoided cost using a process similar to that described for a purchased power agreement with a non-standard duration. The inputs and methodology used for the Schedule PP rates approved in Docket No. E-100, Sub 117, were used to determine the annualized combined capacity and energy rates for the twenty-year term, corresponding to the expected life of the solar facilities.

Regarding the Company's two other owned solar facilities, orders approving the transfers of Certificates of Public Convenience and Necessity (CPCN) were issued by the Commission on May 16, 2016 for both the Mocksville (Docket No. E-7, Sub 1098) and the Monroe (Docket No. E-7, Sub 1079) facilities (DEC Solar PV Orders). An annual revenue requirement, including capital and operations and maintenance costs, was calculated for each project for all years of the expected service life of the project. The present value of the total project revenue requirement was levelized over the project life to produce a level annual revenue requirement, which was compared to avoided cost to determine any annual incremental cost subject to recovery through the REPS rider. The avoided cost for these projects is determined in similar fashion to the method used to determine avoided cost for the Company's Solar DG program. The total annual revenue requirements per megawatt hour (MWh) for the facilities, computed based on updated tax benefit assumptions and actual completed project costs as available, were greater than the applicable avoided costs per MWh, as was the case when the projects were submitted for approval in the CPCN proceedings. The Commission in its DEC Solar PV Orders, limited cost recovery for these projects in the Company's REPS riders to the equivalent of the standard REC offer price that DEC was offering to qualifying facilities at the time the purchase agreements were executed for the facilities. DEC witness Williams testified that the Company included for cost recovery in this REPS rider, only the percentage of annual levelized cost equivalent to the standard REC offer price as approved by the Commission in its DEC Solar PV Orders.

The DEC Solar PV Orders also required in the appropriate REPS rider and general rate case proceedings, that DEC itemize the actual monetization of all the following tax benefits included in the Company's revenue requirement analysis of each facility:

(a) the federal Section 199 deduction;
(b) the federal Investment Tax Credit ("ITC") of 30% of the cost of eligible property;
(c) the five-year Modified Accelerated Cost Recovery System (MACRS) tax depreciation; and (d) a property tax abatement of 80% on solar property.

Witness Williams testified that at the time the applications for CPCN were made, federal bonus depreciation was not available for these solar projects, but in late 2015 Congress extended bonus depreciation such that both DEC-owned projects now qualify. The Company's ability to utilize favorable federal bonus depreciation related to many of its new assets has contributed to the lack of taxable income for utilization of ITC. In summary, although DEC experienced some delay in realizing ITC, the accelerated benefits of bonus depreciation mitigate the effect of the delay. The Company complies with the Commission's DEC Solar PV Orders, and limits the amounts included for recovery in this REPS rider to the portion of annual levelized cost equivalent to the standard REC offer price established in the CPCN proceedings.

In addition to costs incurred or projected to be incurred for bundled or unbundled RECs, Revised Williams Exhibit No. 1, pages 1-2, identified the "Other Incremental" and "Research" costs that DEC has incurred or projects to incur in association with REPS compliance. Likewise, 2nd Revised Payne Exhibit No. 3 shows "Other Incremental Cost" and "Research Cost" related to REPS compliance. Witness Williams included the other incremental and research costs that were incurred in 2016 in the EMF calculation. She explained that these costs are estimated for the billing period and included in the proposed REPS rider. Witness Payne testified that "Other Incremental Costs" include labor costs associated with REPS compliance activities and non-labor costs associated with administration of REPS compliance. Public Staff witnesses Boswell and Lucas both confirmed that, as part of its investigation, the Public Staff had scrutinized inclusion of these costs in DEC's proposed REPS rider and did not take issue with any of the costs DEC seeks to recover.

No party disputed DEC's methodology for calculating its avoided costs, costs incurred during the test period, or costs projected to be incurred during the billing period, or for accounting for its sales of RECs.

Based upon the foregoing and the entire record herein, the Commission concludes that DEC appropriately calculated its avoided costs and incremental REPS compliance costs for the test period and the billing period, and that DEC's sale of poultry RECs appropriately offset the costs incurred in the EMF period. Accordingly, the Commission further finds that, for purposes of establishing the REPS EMF rider in this proceeding, DEC's costs for REPS compliance during the test period were $22,225,765, including the costs incurred for its Wholesale Customers, and that these costs were reasonably and prudently incurred; and, for purposes of establishing the REPS Rider, that the Company's projected incremental costs for REPS compliance for the billing period totaling $35,069,965, including the costs incurred for its Wholesale Customers, is appropriate. Finally, the Commission finds that DEC appropriately calculated the costs of its Solar SG program and DEC's other owned solar projects for inclusion in the REPS rider.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding of fact is found in the testimony and exhibits of DEC witnesses Payne and Williams.

In the Commission's Order in the Sub 1106 docket, the Commission required DEC to: (1) work with the Public Staff and continue its refinement of its interconnection allocation cost process related to interconnection labor and other costs; (2) to file a worksheet explaining the discrete costs that DEC includes as "other incremental costs" in all future REPS Rider proceedings; and (3) to file testimony and exhibits in its next REPS Rider proceeding regarding its interconnection costs as specified in the Order.

DEC witness Payne testified that Payne Confidential Exhibit No. 3 is a worksheet detailing the "other incremental costs" included in the DEC REPS filing, listing the labor costs by activity, as directed by the Commission in its order issued August 16, 2017, in Docket No. E-7, Sub 1106 (the proceeding on DEC's previous application for REPS cost recovery). He testified that this exhibit does not include specific costs related to interconnection activities because those costs were omitted from DEC's application consistent with the Commission's order issued on January 17, 2017, in Docket E-2, Sub 1109 (Duke Energy Progress' most recent REPS Rider proceeding). DEC witness Williams also testified in her testimony, that DEC removed all interconnection-related labor costs and that these costs are not included in DEC's application for recovery in this proceeding.

Based upon the foregoing and the entire record herein, the Commission finds that DEC complied with Commission's Order in Docket No. E-7, Sub 1106, by filing a worksheet detailing its "other incremental costs," and specifically its interconnection cost allocation process related to labor and other costs. The Commission further finds that it is appropriate for DEC to continue to file similar worksheets explaining the discrete costs that DEC includes as "other incremental costs" in all future REPS Rider proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17-22

The evidence for these findings of fact is found in the testimony and exhibits of DEC witnesses Payne and Williams, and in the affidavits of Public Staff witnesses Boswell and Lucas.

Revised Williams Exhibit No. 2 shows total North Carolina retail test period (over)-collections (including interest) of $(1,984,079) for the residential class, $(1,608,803) for the general service class, and $(133,106) for the industrial class. As reflected on 2nd revised Williams Exhibit No. 4, witness Williams calculated proposed North Carolina retail monthly per-account REPS EMF credits (excluding regulatory fee) of $(0.10) for residential accounts, $(0.58) for general service accounts, and $(2.39) for industrial accounts. Also on 2nd revised Williams Exhibit No. 4, she calculated the projected North Carolina retail REPS costs for the billing period of $18,785,900 for the residential class, $12,303,695 for the general service class, and $1,019,087 for the industrial class, all excluding regulatory fees. 2nd revised Williams Exhibit No. 4 shows that the proposed monthly prospective REPS riders per customer account, excluding the regulatory fee, to be collected during the billing period are $0.93 for residential accounts, $4.28 for general service accounts, and $17.52 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 thus $0.83 for residential accounts, $3.70 for general service accounts, and $15.13 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 $0.83 for residential accounts, $3.71 for general service accounts, and $15.15 for industrial accounts. As further illustrated on 2nd revised Williams Exhibit No. 4, the Company's REPS incremental cost rider to be charged to each customer account for the billing period is within the annual cost cap established for each customer class in 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 recommended that the Company's proposed annual REPS EMF increment/(decrement) amounts and monthly EMF riders for each customer class be approved. Witness Boswell also stated that, excluding the regulatory fee, the annual decrement REPS EMF riders are \$(1.23), \$(6.97) and \$(28.69) and the monthly decrement REPS EMF riders are \$(0.10), \$(0.58), and \$(2.39), per retail customer account, for residential, general service, and industrial customers, respectively.

Public Staff witness Lucas testified that the Public Staff had reviewed the costs that produced the proposed, revised rates and that the Public Staff takes no issue with these costs. He recommended that the Commission approve the Company's proposed prospective monthly REPS rider amounts per customer account, excluding regulatory fee, of \$0.93 for residential accounts, \$4.28 for general service accounts, and \$17.52 for industrial accounts.

Based upon the foregoing and the entire record herein, the Commission finds that DEC's calculations of its over collection during the test period and costs projected to be incurred during the billing period and the resulting REPS EMF and REPS riders charges for each customer class are reasonable and appropriate. The Commission further finds that the total of each of the proposed charges are well below the respective annual per-account cost limits of \$34.00, \$150.00, and \$1,000.00, as established in G.S. 62-133.8(h)(4). Therefore, the Commission concludes that DEC's total over collection amounts incurred during the test period and the costs projected to be incurred during the billing period and the resulting REPS EMF and REPS rider charges should be approved.

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, 2017 and expiring on August 31, 2018;

2. That DEC shall establish an REPS 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, 2017 and expiring on August 31, 2018;

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 (10) days after the date that the Commission issues orders in both this docket and in Docket No. E-7, Sub 1129;

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 No. E-7, Sub 1129, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten (10) days of the date of this order;

5. That DEC's 2016 REPS compliance report shall be, and hereby is, approved, and the RECs in DEC's 2016 compliance sub-accounts in NC-RETS and those of the Wholesale Customers shall be retired;

6. That DEC 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 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 25th day of August, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

Commissioner Don M. Bailey, whose term expired on June 30, 2017, did not participate in this decision.

DOCKET NO. E-2, SUB 1143

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:
Application by Duke Energy Progress, LLC)
for Approval of Joint Agency Asset Rider) ORDER APPROVING
for Recovery of Costs Related to Facilities) JOINT AGENCY
Purchased from Joint Power Agency) ASSET RIDER
Pursuant to G.S. 62-133.14 and Rule R8-70) ADJUSTMENT

HEARD: Tuesday, September 19, 2017 at 10:00 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

BEFORE: Chairman Edward S. Finley, Jr., Presiding; and Commissioner Bryan E. Beatty, Commissioner ToNola D. Brown-Bland, Commissioner Jerry C. Dockham, Commissioner James G. Patterson Commissioner Lyons Gray and Commissioner Daniel G. Clodfelter

APPEARANCES:

For Duke Energy Progress, LLC:

Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation, NCRH 20/Post Office Box 1551, Raleigh, North Carolina 27602-1551

For the Using and Consuming Public:

Dianna Downey, Staff Attorney, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

For the Carolina Utility Customers Association, Inc.:

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

For the Carolina Industrial Group for Fair Utility Rates II:

Adam Olls and Warren Hicks, Bailey & Dixon, LLP, Post Office Box 1351, Raleigh, North Carolina 27602

BY THE COMMISSION: On June 21, 2017, 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 G.S. 62-133.14 and Commission Rule R8-70. DEP's application was accompanied by the testimony and exhibits of LaWanda M. Jiggetts – Rates and Regulatory Strategy Manager. In its application and pre-filed testimony, DEP sought approval of the proposed rider, which incorporated a Company proposed adjustment to its North Carolina retail base rates in its pending general rate case.

On July 6, 2017, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice, in which the Commission, among other things, set this matter for public witness and expert witness hearings, established discovery guidelines, and provided for public notice of the hearings.

On June 30, 2017, Carolina Industrial Group for Fair Utility Rates II (CIGFUR II) filed its petition to intervene. The Commission granted the petition on July 5, 2017. On July 11, 2017, Carolina Utility Customers Association, Inc. (CUCA) filed its petition to intervene. CUCA's petition was granted on July 13, 2017. The intervention and participation by the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On September 7, 2017, the Public Staff filed the testimony of Michael C. Maness, Director of the Accounting Division of the Public Staff.

On September 12, 2017, DEP filed the supplemental testimony and exhibits (including revised exhibits) of witness Jiggetts.

No other party pre-filed testimony in this docket.

On September 13, 2017, DEP filed its affidavits of publication.

On September 13, 2017, DEP and the Public Staff filed a Joint Motion to Excuse All Witnesses from appearing at the hearing. The Commission granted this motion on September 15, 2017.

This matter came on for hearing as scheduled on September 19, 2017. No public witnesses appeared. Because the parties had waived cross-examination of witnesses, DEP asked that the Company's application and the direct and supplemental testimony of witness Jiggetts be copied into the record and that her initial exhibits and revised exhibits be entered into evidence. The Commission granted those requests.

The Public Staff also moved into evidence the testimony of witness Maness. That request was also granted. No other party presented witnesses.

Based upon the foregoing, DEP's verified Application, the testimony, supplemental testimony, initial exhibits, and revised exhibits received into evidence at the hearing, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. DEP is a duly organized corporation existing under the laws of the State of North Carolina, engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina and South Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. DEP is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.14 and Commission Rule R8-70. 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.

2. G.S. 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 information required by Commission Rule R8-55.

3. 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 is January 1, 2016 through December 31, 2016. 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 under-recovery 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 Joint Agency Asset Rider. This cumulative balance will accrue a monthly return as prescribed by the Rule.

4. The annual levelized costs associated with the acquisition of the Joint Units at the time of purchase were $61.772 million. DEP also requested an additional $8.690 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 G.S. 62-133.14(b)(1).

5. DEP requested $7.116 million for the annual amortization of costs incurred during the four-month period after the purchase of the Joint Units (July 31, 2015) but prior to the initial JAAR rates becoming effective (December 1, 2015), which were deferred by the Company. The annual amortization is based on a three-year amortization period. To the extent the costs underlying the $7.116 million are acquisition costs, such costs are deemed reasonable and prudent under G.S. 62-133.14(b)(1). The Commission finds it reasonable for the Company to recover the remainder of the estimated costs during the rate period, subject to true-up through the Joint Agency Asset RRF.

6. DEP requested an additional $9.911 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.

7. DEP estimates the annual non-fuel operating costs from December 1, 2017 to November 30, 2018 to be $71.096 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.

8. DEP originally requested $0.212 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.

9. In its supplemental testimony and exhibits, DEP requested to make a reduction in the total prospective annual revenue requirement by $86.659 million to reflect the reduction in the North Carolina retail jurisdiction's portion of financing and operating costs related to DEP's other used and useful generating facilities owned at the time of the acquisition. This reduction in costs assigned to North Carolina retail customers results from greater costs being assigned to wholesale customers because the Company is now supplying the entire electric requirements of NCEMPA. However, DEP has proposed to make this same reduction in the base rates to be established in DEP's pending general rate case, Docket No. E-2, Sub 1142. DEP proposes that if the adjustment is accepted in the rate case, DEP will immediately file a request to remove the adjustment from its JAAR rates, which would result in a substantial increase in the JAAR rates. The Commission does not accept the Company's proposal to implement the JAAR rates proposed in its supplemental testimony and revised exhibits.

10. In its application and original testimony in this proceeding, DEP requested a total of $151.575 million for the prospective component of its North Carolina retail revenue requirement, for the period December 1, 2017 through November 30, 2018, associated with the acquisition and operating costs of NCEMPA's undivided ownership interest in the Joint Units. The Commission finds the anticipated costs underlying DEP's original proposed prospective total revenue requirement to be reasonable and prudent for purposes of this proceeding, and recovery of this amount to be reasonable and appropriate.

11. In addition to the prospective components, DEP requested $2.891 million in its application and testimony in this proceeding for the Joint Agency Asset RRF component of its North Carolina retail revenue requirement for the period December 1, 2017 through November 30, 2018, related to the under-recovery of financing and non-fuel operating costs through the test year ended December 31, 2016. The Commission finds the actual costs and credits underlying this true-up amount to be reasonable and prudent for purposes of this proceeding, and recovery of this amount to be reasonable and appropriate.

12. DEP's proposed rates consist of a prospective component related to the future billing period December 2017 through November 2018 and a Joint Agency Asset RRF component that accomplishes the true-up of costs incurred through the test year ended December 31, 2016.

13. Under 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 1023, DEP's last 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	0.00467	0.00009	0.00476
Small General Service	SGS, SGS-TOUE	0.00533	0.00009	0.00542
Medium General Service	CH-TOUE, CSE, CSG	0.00424	0.00009	0.00433
Seasonal and Intermittent Service	SI	0.00685	0.00009	0.00694
Traffic Signal Service	TSS, TFS	0.00252	0.00009	0.00261
Outdoor Lighting Service	ALS, SLS, SLR, SFLS	0.00000	0.00000	0.00000
Demand Rate Classes (dollars per kilowatt)				
Medium General Service	MGS, GS-TES, AP-TES, SGS-TOU	1.39	0.03	1.42
Large General Service	LGS, LGS-TOU	1.44	0.03	1.47

*Incremental Rates, shown above, include North Carolina regulatory fee of 0.14%.

14. Commission Rule R8-70(e)(2) requires the Company to file a monthly report containing such information as may be agreed to by the Public Staff and DEP and approved by the Commission. The Company and the Public Staff have worked together to develop the details and procedures for the monthly reporting requirement, the format of which was submitted for approval by the Commission. The report would be filed within 60 days of the end of the subject month. The Commission finds that the format, content and timing of the proposed monthly report is reasonable and acceptable and is approved.

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. 2-3

The evidence for these Findings of Fact can be found in DEP's application, G.S. 62-133.14, and Commission Rule R8-70.

Under 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 equal to the weighted average cost of capital as authorized in the utility's most recent general rate case.

The utility may recover an estimate of operating costs based on the experience of the test period and the costs projected for operation of the Joint Units for the next twelve months, subject to the filing of an annual adjustment including any under or over-recovery, 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 the G.S. 62-133.14 and the Commission Rule R8-70.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-5

The evidence for these Findings of Fact can be found in the testimony and supplemental testimony of DEP witness LaWanda M. Jiggetts and in the testimony of Public Staff witness Michael C. Maness.

Witness Jiggetts' revised exhibits[1] reflect that DEP's annual levelized cost associated with the acquisition price of the Joint Units was $61.772 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

[1] Witness Jiggetts filed a full set of her exhibits with her supplemental testimony, but only certain of them were actually revised and so marked. For purposes of convenience, however, the entire set of exhibits filed with her supplemental testimony will be referred to herein as her "revised exhibits."

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 $8.690 million associated with assets purchased that were not included as part of the levelized costs. In her 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.

Additionally, the Company deferred financing and operating costs related to the purchase of the Joint Units following the acquisition, but prior to the effective date of the JAAR. The annual amortization over a three-year period of these deferred costs is $7.116 million. Witness Jiggetts' revised exhibits reflect a three-year amortization of these costs.

G.S. 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' revised 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 3% North Carolina state income tax rate that became effective January 1, 2017.

In his testimony 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. Additionally, the Public Staff's investigation included the review of responses to written and verbal data requests, as well as discussions with the Company. 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 that except for one item (discussed below in Evidence and Conclusions for Finding of Fact No. 9), 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.

Witness Maness also noted in his testimony that this is the first JAAR proceeding in which the Company has included costs for nuclear fuel dry cask storage. As explained by the Company in response to a Public Staff data request, the Company inadvertently left out these costs in its initial calculations of incremental costs. However, the Company noted that as invoices for dry cask storage were paid from August 1, 2015 forward, there was an incremental rate base amount on the books that corresponded to the amount that would have been reimbursed by NCEMPA if the acquisition of the undivided ownership interests had not taken place. Witness Maness testified that the Public Staff reviewed these costs and believes it is appropriate to include them in the JAAR.

Based on the evidence on the record, the Commission concludes that, pursuant to 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 $61.772 million annually, the annual amount of $8.690 million of financing and operating costs associated with acquisition costs that are not levelized, and $7.116 million annually reflecting a three-year amortization of deferred costs including a return on the deferred costs over this amortization period. To the extent the costs underlying these amounts are acquisition costs, such costs are deemed reasonable and prudent under 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. 6-7

The evidence for these Findings of Fact can be found in DEP's Application, the testimony and supplemental testimony of DEP witness LaWanda M. Jiggetts and the testimony of Public Staff witness Michael C. Maness.

The Company requested annual costs of $9.911 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, 2017 through November 30, 2018, and an estimated $71.096 million for annual non-fuel operating costs over the period December 1, 2017 to November 30, 2018. Under 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 testimony filed in this proceeding, and stated that the Public Staff recommended approval of the Company's revised 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. 8

The evidence for this Finding of Fact can be found in the testimony of DEP witness Lawanda M. Jiggetts.

Witness Jiggetts' original exhibits reflected a regulatory fee amount equal to $0.212 million based on the estimated JAAR costs for the period December 1, 2017 through November 30, 2018. The Commission concludes that the calculation of the regulatory fee is just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 9-10

The evidence for these Findings of Fact can be found in DEP's application and the testimony and supplemental testimony of DEP witness LaWanda M. Jiggetts, as well as the testimony of Public Staff witness Michael C. Maness.

Under 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 in the Company's filing, the annual revenue reduction to North Carolina retail revenue requirements for the test period January 2016 through December 2016 totaled $87 million. For the prospective period December 2017 through November, 2018, the reduction is $7 million. Witness Jiggetts testified that the reduction was due to the Company's base rate request filed in Docket No. E-2, Sub 1142. The reallocation between retail and wholesale jurisdictions is reflected in the rates proposed as a part of that filing and as such the annual revenue reduction was not included in the JAAR revenue requirements beyond December 2017.

Public Staff witness Maness did not oppose the recovery of this revenue requirement component in his testimony filed in this proceeding. However, witness Maness proposed an adjustment to the Company's allocation adjustment as it was originally filed. He testified that the prospective JAAR annual revenue requirement in the current proceeding of $151,575,000 is an increase of approximately $77.3 million above the $74,274,000 of costs estimated for the most recent JAAR rate period of December 2016 through November 2017. Public Staff witness Maness testified that the increase was largely due to DEP's exclusion of the large majority of the amount representing the jurisdictional allocation credit in G.S. 62-144.14(b)(4) from the JAAR revenue requirement, because the Company has reflected the credit in the base rates it has proposed in its pending general rate case proceeding in Docket No. E-2, Sub 1142. He testified that the proposed inclusion of the allocation credit in base rates is reflected in the Company's filing in Sub 1142 and has not yet been approved by the Commission. The Commission's order approving rates in Sub 1142 is expected to be issued prior to February 1, 2018; the proposed JAAR rates are scheduled to go into effect on December 1, 2017. Witness Maness reasoned that making an assumption in the JAAR proceeding that the Company's proposed base rate treatment of the allocation credit will be approved is somewhat premature. Instead, it would be reasonable to keep the full annual allocation credit in the JAAR prospective revenue requirement calculation for purposes of determining the JAAR rates to go into effect on December 1, 2017. He also recommended that should the Commission approve, in Sub 1142, the transfer of the allocation credit to base rates, the Commission should also provide for an immediate filing of a proposed revised set of JAAR rates that will conform to the Sub 1142 filing. Any under-collection of JAAR revenue requirements during the interim between December 1, 2017 and the approval of revised

JAAR rates in the first part of 2018 could be included in the regular true-up of JAAR revenue requirements for the applicable months, whenever those months are trued up in a future JAAR annual proceeding.

On September 12, 2017, DEP filed the supplemental testimony and exhibits of witness Jiggetts. She testified that the Company is agreeable to the approach recommended by the Public Staff to reflect the full jurisdictional reallocation credit of $86.659 million in the revenue requirement and rate calculations in this proceeding, and revised rates that reflect the full jurisdictional reallocation credit for the prospective billing period were submitted for approval in the supplemental filing. Consequently, the revised prospective JAAR annual revenue requirement based on the revised exhibits filed by witness Jiggetts of $72,026,000 reflects a decrease of approximately $2.2 million compared to the $74,274,000 of costs estimated for the most recent JAAR rate period of December 2016 through November 2017.

The Commission has two options in this docket. The first option is to approve the JAAR rates initially proposed by DEP, which rates were not challenged or opposed by any party. DEP initially excluded the vast majority of the allocation credit from its proposed JAAR rates. As a result, DEP's initially proposed rates were substantially higher than the JAAR rates presently in effect. For example, the present residential rate is $0.00223/kWh, and DEP's initial proposed residential JAAR rate was $0.00476/kWh. Thus, the initial proposed JAAR rate would result in an increase of $2.53 per month in the bill of a residential customer using 1,000 kWh. Increases of a similar proportion would be made in the JAAR rates of other customer classes. The Public Notice approved by the Commission in this docket and published by DEP gave customers notice of the specific JAAR rates initially proposed by DEP. If the Commission in DEP's general rate case accepts the allocation credit as a component of base rates, as recommended by DEP and agreed to by the Public Staff[1], then DEP's JAAR rates as initially proposed should not require adjustment untl the next annual JAAR proeeding, since the vast majority of the allocation credit was not included by DEP in the calculation of its initially proposed JAAR rates.

The Commission's second option is to approve the revised JAAR rates proposed by DEP. DEP's revised position is to include the vast majority of the allocation credit in the computation of its JAAR rates. If approved, the result would be a significant decrease in the JAAR rates that would go into effect on December 1, 2017. For example, DEP's revised proposed residential JAAR rate is $0.00231/kWh, only $0.0008/kWh higher than the current residential JAAR rate. Thus, instead of an increase of $2.53 per month per 1,000 kWh, as initially proposed by DEP, a residential customer would see an increase of only $0.08 per month per 1,000 kWh. Increases of similarly small proportions would be made in the JAAR rates of other customer classes. However, if the Commission in DEP's general rate case accepts the allocation credit as a component of base rates, as recommended by DEP and agreed to by the Public Staff, then the Commission would have to remove the vast majority of the allocation credit from DEP's JAAR rates and make a substantial upward adjustment to those rates, essentially bringing DEP's JAAR rates back to the levels initially proposed by DEP in this docket. In order to make those changes, which would be made sometime in early 2018, the Commission would have to reopen this docket, schedule another

[1] Pre-Filed Direct Testimony of Michael C. Maness in Docket No. E-2, Sub 1142, at pp. 33-35.

hearing, and require DEP to publish notice of the hearing and the proposed upward adjustment to its JAAR rates. As a result, DEP's customers would receive a notice of changes in their JAAR rates in December 2017, a notice of a proposed change in their JAAR rates in early 2018, and a notice of another change in their JAAR rates sometime around May or June 2018.

The Commission concludes that the first option, approval of the JAAR rates initially proposed by DEP, is the most appropriate and reasonable course of action. Under that course of action, if the Commission in DEP's rate case accepts the allocation credit as a component of base rates, then DEP's JAAR rates should not require adjustment until the next annual JAAR proceeding. If the Commission rejects or adjusts the allocation credit as a component of base rates, any adjustment for over or under-recovery of JAAR rates by DEP during the intervening months could be made in DEP's 2018 JAAR proceeding as a part of the RRF, thereby avoiding the procedural quagmire and confusion to ratepayers that could occur under option two.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this Finding of Fact can be found in DEP's application, the testimony and supplemental testimony of DEP witness LaWanda M. Jiggetts, DEP's exhibits to the JAAR, and the testimony of Public Staff witness Michael C. Maness.

The Company requested a Joint Agency Asset RRF adjustment of $2.891 million related to the under-recovery of costs incurred through test year ended December 31, 2016. 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 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 recovery of this rate component in his testimony filed in this proceeding. The Commission finds the actual costs and credits underlying this true-up amount to be reasonable and prudent, and that recovery of this amount is reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-14

The evidence for these Findings of Fact can be found in DEP's application, the testimony and supplemental testimony of DEP witness LaWanda M. Jiggetts, DEP's revised exhibits to the JAAR, and the testimony of Public Staff witness Michael C. Maness.

Pursuant to 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 1023. Witness Jiggetts testified that DEP allocated the original JAAR revenue requirement, excluding the vast majority of the allocation credit, based on the methodology consistent with its last general rate case to produce the rates reflected for each rate class as shown below.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

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	0.00467	0.00009	0.00476
Small General Service	SGS, SGS-TOUE	0.00533	0.00009	0.00542
Medium General Service	CH-TOUE, CSE, CSG	0.00424	0.00009	0.00433
Seasonal and Intermittent Service	SI	0.00685	0.00009	0.00694
Traffic Signal Service	TSS, TFS	0.00252	0.00009	0.00261
Outdoor Lighting Service	ALS, SLS, SLR, SFLS	0.00000	0.00000	0.00000
Demand Rate Classes (dollars per kilowatt)				
Medium General Service	MGS, GS-TES, AP-TES, SGS-TOU	1.39	0.03	1.42
Large General Service	LGS, LGS-TOU	1.44	0.03	1.47

*Incremental Rates, shown above, include North Carolina regulatory fee of 0.14%.

As discussed above, the Commission concludes that DEP's new JAAR rates should be those initially proposed by DEP, excluding the vast majority of the allocation credit.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence for this Finding of Fact can be found in DEP's application, the testimony and supplemental testimony of DEP witness LaWanda M. Jiggetts, DEP's initially filed exhibits to the JAAR, and the testimony of Public Staff witness Michael C. Maness.

The Company submitted the proposed monthly report format as Exhibit M in its initially filed exhibits. The format consists of four schedules (and various sub-schedules) that will summarize the components of the revenue requirement for the applicable test year. Public Staff witness Maness testified that the Public Staff believes that this reporting format will provide the data necessary to keep the Commission informed regarding the costs applicable to the JAAR that are being incurred on an ongoing basis and will be a beneficial resource to the Public Staff and any other parties that wish to examine such costs during any particular time period. The Public Staff recommended approval of the proposed format and that the Commission require the Company to begin filing the report on a monthly basis as soon as practicable. The Commission finds and concludes that the proposed monthly reporting format as proposed by DEP and the Public Staff is reasonable and is approved. DEP shall file such monthly reports with the Commission within sixty (60) days of the end of the subject month.

IT IS, THEREFORE, ORDERED as follows:

1. That DEP shall be allowed to charge in a rider $154.466 million 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 initial testimony of DEP witness Jiggetts;

3. That the revised rates reflected in the Schedule listed in Finding of Fact No. 13 of this Order shall be, and are hereby, approved effective for service rendered on and after December 1, 2017;

4. That DEP shall work with the Public Staff to jointly prepare a proposed notice to customers of the rate adjustments ordered by the Commission in Docket Nos. E-2, Subs 1143, 1144 and 1146 and the Company shall file the proposed notice to customers for approval as soon as practicable; and

5. That DEP shall commence filing the monthly report using the agreed upon format as soon as practicable.

ISSUED BY THE ORDER OF THE COMMISSION.
This the 17th day of November, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

DOCKET NO. E-2, SUB 1145

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC, for	)	
Approval of Demand-Side Management and	)	ORDER APPROVING DSM/EE
Energy Efficiency Cost Recovery Rider Pursuant	)	RIDER AND REQUIRING FILING
to G.S. 62-133.9 and Commission Rule R8-69	)	OF CUSTOMER NOTICE

HEARD: Tuesday, September 19, 2017, at 9:53 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding, Chairman Edward S. Finley, Jr., and Commissioners Bryan E. Beatty, Jerry C. Dockham, James G. Patterson, Lyons Gray, and Daniel G. Clodfelter

APPEARANCES:

For Duke Energy Progress, LLC:
Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation, Post Office Box 1551, Raleigh, North Carolina 27602

For Carolina Industrial Group for Fair Utility Rates II:
Adam Olls and Warren K. Hicks, Bailey & Dixon, LLP, Post Office Box 1351, Raleigh, North Carolina 27602

For North Carolina Sustainable Energy Association:
Peter H. Ledford, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For Carolina Utility Customers Association, Inc.:
Robert F. Page, Crisp & Page, LLP, 4010 Barrett Drive, Suite 205, Raleigh, NC 27609

For Southern Alliance for Clean Energy and North Carolina Justice Center:
Nadia Luhr, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For the Using and Consuming Public:
David T. Drooz, Chief Counsel, 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: 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 to recover all reasonable and prudent costs incurred for the adoption and implementation of new demand-side management (DSM) and energy efficiency (EE) programs. The Commission is also authorized to award incentives to electric utilities for adopting and implementing new DSM/EE programs, including rewards based on the sharing of savings achieved by the programs. 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 the reasonable and prudent costs incurred for adopting and implementing new DSM/EE measures previously approved by the Commission pursuant to Commission Rule R8-68. Under Commission Rule R8-69, such rider consists of the utility's forecasted costs during the rate period, similarly forecasted performance incentives (including net lost revenues (NLR)) as allowed by the Commission, and an experience modification factor (EMF) rider to collect the difference between the utility's actual reasonable and prudent costs and incentives incurred and earned during the test period and the actual revenues realized during the test period under the DSM/EE rider (based on previous forecasts) then in effect.

Docket No. E-2, Sub 1145

On June 21, 2017, Duke Energy Progress, LLC (DEP or the Company), filed an application for approval of its annual DSM/EE cost recovery rider (Application) pursuant to G.S. 62-133.9 and Commission Rule R8-69. Along with the Application, DEP filed the associated testimony and exhibits of Carolyn T. Miller and Robert P. Evans (Initial Filing) in support of recovery of DSM/EE costs and utility incentives forecasted for the rate period of January 1, 2018, through December 31, 2018, including program expenses, amortizations and carrying costs associated with deferred prior period costs, Distribution System Demand Response (DSDR) depreciation and capital costs, NLR, and program and portfolio performance incentives (PPI). In addition, DEP asked for approval of an EMF component of its DSM/EE rider to true-up an under-recovery of its actual DSM/EE costs and utility incentives during the test period of January 1, 2016, through December 31, 2016.

On July 6, 2017, the Commission issued an Order scheduling a public hearing in this matter for September 19, 2017, immediately following the 9:30 a.m. hearings in Docket No. E-2, Subs 1146 and 1144, establishing discovery guidelines, providing for intervention and testimony by other parties, and requiring public notice.

The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On June 30, 2017, the Carolina Industrial Group for Fair Utility Rates II (CIGFUR II) filed a petition to intervene, which was granted by Commission order on July 5, 2017.

On July 6, 2017, the North Carolina Sustainable Energy Association (NCSEA) filed a petition to intervene, which was granted by Commission order on July 10, 2017.

On July 11, 2017, the Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene, which was granted by Commission order on July 13, 2017.

On September 1, 2017, the Southern Alliance for Clean Energy (SACE) and North Carolina Justice Center (NC Justice Center) filed a petition to intervene, which was granted by Commission order on September 8, 2017.

On September 5, 2017, SACE and NC Justice Center filed the testimony and exhibit of James Grevatt. Also on September 5, 2017, the Public Staff filed the affidavit and exhibits of Michael C. Maness, the testimony and exhibit of David M. Williamson, a public version of the testimony of John R. Hinton, and a confidential version of witness Hinton's testimony.

On September 12, 2017, DEP filed the Supplemental Testimony of witness Timothy J. Duff, Supplemental Testimony of witness Miller, Supplemental Miller Exhibits 1, 2, and 3, and Supplemental Evans Exhibits 1, 2, and 9 (Supplemental Filing).

On September 13, 2017, DEP filed a joint motion on behalf of itself, the Public Staff, SACE, and NC Justice Center requesting that these parties' witnesses be excused from appearing at the hearing and that their prefiled testimony, exhibits, and affidavits be received into the record. On September 15, 2017, the Commission granted that motion.

On September 13, 2017, DEP filed its affidavits of publication indicating that the Company had provided notice in newspapers of general circulation as required by the Commission's July 6, 2017 Order.

On September 19, 2017, the hearing was held as scheduled. No public witnesses appeared at the hearing.

On September 21, 2017, DEP filed the Affidavit of witness Evans authenticating Supplemental Evans Exhibit 9.

On October 24, 2017, DEP and the Public Staff filed a Joint Proposed Order.

Also on October 24, 2017, SACE and NC Justice Center filed its post-hearing 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 that Order, the Commission approved, with certain modifications, an Agreement and Stipulation of Partial Settlement (Stipulation) between DEP, the Public Staff, and 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 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 (Reconsideration Order). The Original Mechanism as approved after reconsideration 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

G.S. 62-133.9, Commission Rules R8-68 and R8-69, and the additional principles set forth in the 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. In that Order, the Commission approved an agreement between DEP, the Public Staff, the 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 G.S. 62-133.9, Commission Rules R8-68 and R8-69, and the additional principles set forth in the Revised Mechanism.

In the present proceeding, based upon DEP's verified application, the affidavits, testimony, and exhibits received into evidence, and the record as a whole, the Commission makes the following

FINDINGS OF FACT

1. DEP is a duly organized limited liability company (LLC) 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 G.S. 62-133.9 and Commission Rule R8-69.

2. The test period for purposes of this proceeding extends from January 1, 2016, through December 31, 2016.

3. The rate period for purposes of this proceeding extends from January 1, 2018, through December 31, 2018.

4. DEP has requested approval for the recovery of costs, and utility incentives where applicable, related to the following DSM/EE programs:

<u>Residential</u>

- Appliance Recycling
- Energy Education Program
- Multi-Family EE
- My Home Energy Report (MyHER) (formerly, EE Benchmarking)
- Neighborhood Energy Saver (Low Income)
- Home Energy Improvement
- New Construction
- EnergyWise (Load Control)
- Save Energy and Water Kit
- Energy Assessment

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
- Business Energy Report pilot
- EnergyWise for Business (Load Control)

Residential and Non-Residential

- DSDR
- EE Lighting

These programs are eligible for cost and utility incentive recovery, where applicable.

5. The Appliance Recycling Program should be canceled as of December 31, 2017.

6. For purposes of inclusion in this DSM/EE rider, the Company's portfolio of DSM and EE programs is cost-effective.

7. In its next rider application, DEP should address the continuing cost-effectiveness of the Smart $aver Performance (Custom) Program, the Smart $aver Performance (Prescriptive) Program, the Smart $aver Performance Incentive Program, and the Home Energy Improvement Program[1]. With respect to the Smart $aver Performance (Custom) Program and the Smart $aver Performance (Prescriptive) Program, the Company should include a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program(s).

8. DEP shall file updated cost-effectiveness scores for DSDR in each of DEP's DSM/EE rider proceedings.

9. The evaluation, measurement, and verification (EM&V) reports filed as Evans Exhibits A, B, and C are acceptable for purposes of this proceeding and should be considered complete for purposes of calculating program impacts. DEP has appropriately incorporated the results of these EM&V reports into the DSM/EE rider calculations.

[1] Modifications to the Home Energy Improvement Program were approved by the Commission on September 11, 2017, in Docket No. E-2, Sub 936. The modifications are projected to make the program cost-effective.

10. The EM&V reports for the Small Business Energy Saver Program (Evans Exhibit D) and the Multi-Family EE Program (Evans Exhibit E) should be revised as discussed by Public Staff witness Williamson and refiled in the next rider proceeding and in their respective program dockets.

11. The EM&V recommendations concerning future EM&V reports contained in the testimony of Public Staff witness Williamson are appropriate for inclusion in future EM&V reports for the applicable EE programs, when feasible and not cost prohibitive, including certain program vintages that remain to be verified and trued up.

12. In its Initial Filing, DEP requested the recovery of NLR in the amount of $40,782,610 and PPI in the amount of $16,807,898 through the EMF component of the total DSM/EE rider, and NLR of $20,774,677 and PPI of $22,371,330 for recovery in the forward-looking, or prospective component of the total rider. As a result of additional analysis performed by DEP and provided to the Public Staff during the course of the proceeding, the Company corrected its EMF NLR amount to $40,220,166, as reflected in its Supplemental Filing. In addition, by agreement between DEP and the Public Staff, and the Company reduced its projected PPI estimate by $2,100,000 to $20,271,330, as reflected in its Supplemental Filing. The Public Staff agreed with these adjustments. DEP's proposed recovery of NLR and PPI, as adjusted by the Supplemental Filing, is consistent with the Original Mechanism and Revised Mechanism, and is appropriate, subject to further review to the extent allowed in the Mechanisms.

13. 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 $157,162,423, and this is the appropriate amount to use to develop the forward-looking DSM/EE revenue requirement. This amount is the total of the $159,262,423 proposed in DEP's Initial Filing and the total prospective PPI adjustment of $(2,100,000) reflected in DEP's Supplemental Filing.

14. 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 $145,464,161. This amount is the total of the $146,026,605 proposed in DEP's Initial Filing and the total NLR EMF adjustment of $(562,444) reflected in DEP's Supplemental Filing. The reasonable and appropriate 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 $143,996,006. Therefore, the test period revenue requirement, minus the test period revenues collected and miscellaneous adjustments, leaves $1,468,155 as the test period under-collection that is appropriate to use as the DSM/EE EMF revenue requirement in this proceeding.

15. After assignment or allocation to customer classes in accordance with 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	$92,848,553
General Service EE	58,058,006
General Service DSM	5,860,403
Lighting	395,461
Total	$157,162,423

DSM/EE EMF:

Residential	$2,399,583
General Service EE	771,258
General Service DSM	(1,697,547)
Lighting	(5,139)
Total	$1,468,155

16. 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	15,679,350,211
General Service EE	10,123,944,285
General Service DSM	10,075,669,299
Lighting	370,385,092

17. The appropriate DSM/EE EMF billing factors, excluding NCRF, are increments of: 0.016 cents per kWh for the Residential class; 0.008 cents per kWh for the EE component of the General Service classes; and decrements of (0.017) cents per kWh for the DSM component of the General Service classes, and (0.001) cents per kWh for the Lighting class. These DSM/EE EMF billing factors do not change when the NCRF of 0.140% is included.

18. The appropriate forward-looking DSM/EE rates to be charged by DEP during the rate period, excluding NCRF, are increments of: 0.593 cents per kWh for the Residential class; 0.573 cents per kWh for the EE component of the General Service classes; 0.058 cents per kWh for the DSM component of the General Service classes; and 0.107 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 of 0.140%, are increments of: 0.594 cents per kWh for the Residential class;

0.574 cents per kWh for the EE component of the General Service classes; 0.058 cents per kWh for the DSM component of the General Service classes; and 0.107 cents per kWh for the Lighting class.

19. The agreement between the Company and Public Staff to adjust the Vintage Year 2018 Portfolio Performance Incentive (PPI) by $2.1 million is reasonable and should be approved.

20. 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. No change in the allocation ratio applicable to capacitors was necessary for 2017. The allocation ratio applied to regulators was reduced from 79.45% to 77.79% for 2017. Annual review of the allocation ratios will continue, will be reported to the Public Staff each year, and any changes will be addressed in future rider proceedings.

21. Based on the recommendations of SACE and NC Justice Center witness Grevatt, the Commission finds that DEP should continue to utilize its Collaborative to discuss and consider the following: (a) the potential for comprehensive program approaches with longer measure lives, such as home retrofits and HVAC system improvements; (b) maximization of cross-program marketing in behavior, audit, and kit programs; (c) opportunities to save more energy in multi-family housing, including in common areas and for commonly-metered systems; (d) expansion of the Company's low income program offerings; (e) ways to continue to promote adoption of a greater range of measures through the Company's Small Business Energy Saver Program; (f) ways to encourage participation of non-residential customers who are eligible to opt out, including making sure that the available programs meet these customers' needs and by providing personalized outreach to engage them; and (g) if DEP launches a large-scale deployment of Advanced Metering Infrastructure (AMI), it should use the AMI capabilities to drive more EE and DSM for DEP customers.

22. The revisions to the Revised Mechanism as set out in Maness Exhibit II are reasonable and should be approved effective January 1, 2018.

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 consistent with the Revised Mechanism approved by the Commission. The proposed rate period and test period are reasonable.

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 Miller and Evans, the testimony of Public Staff witness Williamson, and various Commission orders in program approval dockets.

DEP witness Miller's testimony shows the portfolio of DSM/EE programs that is associated with the Company's request for approval of this rider. 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. Those programs are:

Residential

- Appliance Recycling
- EE Education Program
- Multi-Family EE
- My Home Energy Report
- Neighborhood Energy Saver (Low Income)
- Home Energy Improvement
- New Construction
- EnergyWise (Load Control)
- Save Energy and Water Kit
- Energy Assessment

Non-Residential

- Smart $aver Energy Efficient Products and Assessment
- Smart $aver Performance Incentive
- Small Business Energy Saver
- CIG Demand Response Automation
- Business Energy Report pilot[1]
- EnergyWise for Business (Load Control)

Residential and Non-Residential

- DSDR
- EE Lighting

In his testimony, Public Staff witness Williamson also listed the DSM/EE programs and pilots for which the Company seeks cost recovery and noted that each of these programs and pilots has received approval as a new DSM or EE program and is eligible for cost recovery in this proceeding under G.S. 62-133.9.

[1] The Business Energy Report Pilot was terminated effective June 30, 2017 by Commission Order dated July 25, 2017, in Docket No. E-2, Sub 1072.

Thus, the Commission finds and concludes that each of the programs and pilots listed by witnesses Evans and Williamson has received Commission approval as a new DSM or EE program or pilot and is, therefore, eligible for cost recovery in this proceeding under G.S. 62-133.9.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence in support of this finding can be found in the testimony and exhibits of DEP witness Evans and the testimony of Public Staff witness Williamson.

Evans Exhibit 3 indicates that DEP did not incur expenses in 2016 related to the Appliance Recycling Program. DEP witness Evans testified that the Appliance Recycling Program, which is currently suspended, produced only 5 percent of forecasted energy savings largely due to the bankruptcy of the program vendor and DEP's inability to replace this vendor.

Public Staff witness Williamson testified that given the bankruptcy of the program vendor and DEP's lack of success in finding a replacement vendor, this program should be canceled as of December 31, 2017. He recommended that the Company should continue to pursue potential refunds and other relief from accrued liabilities associated with vendor bankruptcy, and any refunds or relief obtained should be flowed through in future DSM/EE or DSM/EE EMF billing factors, as appropriate.

SACE/NC Justice Center witness Grevatt recommended that DEP should immediately procure an alternate vendor for its Appliance Recycling Program. Though SACE and the NC Justice Center are parties to the Joint Proposed Order, they do not concur with Public Staff witness Williamson's recommendation that the Appliance Recycling Program should be canceled as of December 31, 2017. On October 24, 2017, SACE and the NC Justice Center filed a separate post-hearing brief outlining their position on the Appliance Recycling Program.

The Commission concludes that the Appliance Recycling program should be canceled as of December 31, 2017.

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

The evidence for these findings can be found in the testimony and exhibits of Company witness Evans and the testimony and exhibits of Public Staff witness Williamson.

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 2018 period, the results of which are incorporated in Evans Exhibit No. 7. The analysis did not include any values for DEP's Appliance Recycling Program, as no costs for this Program were included in Vintage 2018 due to its current suspension. DEP's calculations indicate that, with the exception of the Neighborhood Energy Saver (Low Income) Program (which was not cost-effective at the time it was approved by the Commission), the Home Energy Improvement Program, and the Smart $aver Performance Incentive Program (which was implemented on January 1, 2017), all of Company's DSM/EE programs pass both the Total Resource Cost (TRC) and Utility Cost (UC) test. The aggregate portfolio continues to project cost-effectiveness.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

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 UC, TRC, Participant, and Ratepayer Impact Measure (RIM) tests. Witness Williamson explained that the Public Staff places the greatest emphasis on the TRC and UC tests. He indicated that each of the Company's programs was cost-effective under both the TRC and UC tests, with the exception of the Home Energy Improvement Program (TRC of 0.67 and a UC of 0.91), Neighborhood Energy Saver Program (UC of 0.57), Smart $aver Performance (Custom) Program (TRC of 0.98), and Smart $aver Performance Incentive (TRC of 0.40 and a UC of 0.54). Witness Williamson stated that his review indicated that the portfolio as a whole remains cost-effective under the UC, TRC, and Participant tests. Public Staff witness Williamson noted that several programs remain cost-effective, but have TRC scores that have decreased since the 2016 DSM/EE rider proceeding; similarly, several programs have increased in cost-effectiveness since the 2016 proceeding.

Witness Williamson noted that the Company did not provide a cost-effectiveness score for the DSDR program in this proceeding, and the last cost-effectiveness score for the DSDR program was filed on March 30, 2016. He recommended that the Commission specify in its order in this proceeding that, going forward, DEP shall file updated cost-effectiveness scores for all programs within its portfolio, including DSDR, with each of DEP's DSM/EE rider proceedings.

Public Staff witness Williamson testified that the Public Staff and DEP had differing interpretations of Paragraph 70 of the Revised Mechanism as to the appropriate avoided costs to be used in calculations of cost-effectiveness. Paragraph 70 of the Mechanism requires DEP to update both the avoided capacity and avoided energy costs if the current avoided capacity cost rates have changed by 15% or more or the avoided energy cost rates changed by 20% or more. Witness Williamson stated that DEP made its filing in this proceeding in accordance with its belief that neither the 15% or 20% change had occurred; while the Public Staff believed that there had been a change in the rates to require an update of avoided costs. The Public Staff and DEP resolved this issue by agreeing to a monetary adjustment to the Vintage Year 2018 PPI, revisions to the language of Paragraph 70, and other minor changes to the Revised Mechanism. The resolution also provided specific recommendations regarding four programs that appear to be marginal or not cost-effective if avoided costs had been updated: the Smart $aver Performance (Custom) Program, Smart $aver Performance (Prescriptive), Smart $aver Performance Incentive program, and the Home Energy Improvement Program.

Witness Williamson explained that this is the first proceeding where the Company separately calculated the cost-effectiveness of the Smart $aver Performance (Custom) and the Smart $aver Performance (Prescriptive) programs. Both of these programs have been and continue to be part of the Non-Residential Smart $aver EE Products and Assessment program. As indicated in Evans Exhibit 7, the Smart $aver Performance (Custom) program has a TRC of 0.98. While the Smart $aver Performance (Prescriptive) program is shown to have a TRC greater than 1.0 in Evans Exhibit 7, Witness Williamson indicated that it appears that this program would not cost-effective under the updated avoided cost rates. Therefore, consistent with the proposed revisions to the Revised Mechanism, Witness Williamson recommended that the Company monitor the performance of both the Smart $aver Performance (Custom) program and the Smart $aver Performance (Prescriptive) program and 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(s).

The third program Public Staff witness Williamson discussed that would be marginal or not cost-effective if avoided costs were updated was the Smart $aver Performance Incentive program, which was approved in the fall of 2016 and launched in January 2017. He did not recommend any action at this time as it is difficult to assess the actual cost-effectiveness of the program at such an early stage. He noted that by the time of the 2018 rider filing, the program will have matured and its cost-effectiveness could better be assessed.

With respect to the fourth program, the Home Energy Improvement Program, witness Williamson noted that DEP has expressed a strong desire to the Public Staff to continue offering this program. He agreed that such a program is a fundamental EE program for any utility's EE portfolio. He explained that the Company's request to modify the program is expected to improve the program's cost-effectiveness, and that if this request for modification is granted, the program will continue to be eligible for cost recovery pursuant to the Revised Mechanism. On September 11, 2017, the Commission approved the modifications to this program in Docket No. E-2, Sub 936.

DEP has indicated that it agrees with the Public Staff's recommendations with respect to these programs.

The Commission therefore concludes that DEP's portfolio of DSM and EE programs is cost-effective and eligible for inclusion in the Company's DSM/EE rider. Additionally, the Commission concludes that in its next rider application, DEP should address the continuing cost-effectiveness of the Smart $aver Performance (Custom) program, the Smart $aver Performance (Prescriptive) program, the Smart $aver Performance Incentive program, and the Home Energy Improvement program. With respect to the Smart $aver Performance (Custom) Program and the Smart $aver Performance (Prescriptive) Program, the Company should include a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program(s). In addition, if the Commission-approved modifications to the Home Energy Improvement Program do not maintain or improve the program's cost-effectiveness by the Company's next DSM/EE rider proceeding, the program should be terminated at the end of 2018. Finally, DEP shall file updated cost-effectiveness scores for DSDR with each of DEP's DSM/EE rider proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 9-11

The evidence for these findings 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. 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. In addition, actual participation and evaluated load impacts are used prospectively to update estimated NLR. In this proceeding, the Company submitted, as exhibits to witness Evans' testimony, detailed completed EM&V reports or updates for the following programs:

- EnergyWise Program – Winter 2015/2016 (Evans Exhibit A)
- Neighborhood Energy Saver Program – 2015 (Evans Exhibit B)
- EE Lighting Program – 2015 (Evans Exhibit C)
- Small Business Energy Saver Program – 2015 (Evans Exhibit D)
- Multi-Family EE Program – 2014 & 2015 (Evans Exhibit E)

In his testimony, Public Staff witness Williamson testified that with respect to program vintages for which EM&V reports were filed in this proceeding, he does not recommend any adjustment to the impacts at this time. He also testified that he had confirmed through sampling that the updated EM&V data properly flowed into the calculations of net present values (NPV) that serve as the basis for the NLR and PPI calculations. He tracked the data derived from EM&V as they were incorporated into the database, the NPV calculations and, ultimately, the rider calculation. Witness Williamson stated his belief that DEP was appropriately incorporating the results of EM&V into the DSM/EE rider calculations.

In addition, witness Williamson stated that DEP had adopted his EM&V-related recommendations made in the 2017 DSM/EE rider proceeding, Docket No. E-2, Sub 1108, to the extent these recommendations are applicable to the EM&V reports filed in this proceeding. He noted that it was his understanding that DEP's EM&V evaluator intended to incorporate these recommendations in future EM&V reports. Witness Williamson also provided recommendations concerning the content of future EM&V studies for particular EE programs, noting that DEP's implementation of these recommendations would be subject to the consideration of whether the recommendation would be cost prohibitive. Public Staff witness Williamson recommended that:

1. Future evaluations of the Multi-Family EE Program should include a billing analysis and more specific data on bulbs being replaced. However, if it is not feasible to do so, then the evaluator should address what limitations in program design or evaluation resources would prevent a billing analysis from being conducted;[1]

2. Future evaluations of the Small Business Energy Saver Program should (a) incorporate HVAC interactive effects and update the coincidence factors for lighting measures, and (b) begin tracking the heating and cooling types of participants to improve estimates of the HVAC interaction factors;

3. Future evaluations of the Neighborhood Energy Saver Program, and similar programs, should consider utilizing state-level specific data in its evaluations when providing estimates in the program's EM&V review, unless cost-prohibitive; and

[1] Witness Williamson noted that in response to a Public Staff data request, DEP indicated that it had already implemented the Public Staff's recommendation concerning the removed bulbs beginning in 2016.

4. Future DEP evaluation reports should include a discussion of key methodological differences between past and present evaluations, including differences in methodologies across multiple programs that offer similar or identical measures. If changes to the methodological approaches are warranted, the Public Staff recommends that the EM&V reports should also describe key methodological changes or differences between past and present studies. This information would help clarify the EM&V reports and address any concerns the Public Staff may have with the changes to methodologies or changes to the program attributes that may result.

Witness Williamson concluded that, with the exception of the Small Business Energy Saver Program EM&V Report (Evans Exhibit D) and the EM&V Report for the Multi-Family EE Program (Evans Exhibit E), the EM&V of the vintages of the measures covered by the remaining reports filed in this proceeding should be considered complete. He recommended that the Small Business Energy Saver Program EM&V Report be revised to correct an error, which would affect Vintages 2016 through 2018. With respect to the Multi-Family EE Program EM&V Report, witness Williamson discussed three issues the Public Staff had found with calculations, and recommended that the evaluator address these issues and that DEP file a revised report. Witness Williamson explained that any revisions would affect Vintages 2016 through 2018.

With the exception of those EM&V-related recommendations made by Public Staff witness Williamson for revisions to Evans Exhibits D and E and regarding future EM&V (none of which were disputed by DEP), 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, and C are acceptable for purposes of this proceeding and should be considered complete for purposes of calculating program impacts; that the EM&V reports for Small Business Energy Saver Program (Evans Exhibit D) and the Multi-Family EE Program (Evans Exhibit D) should be revised as discussed by Public Staff witness Williamson and refiled in the next rider and in their respective program approval dockets; and that the EM&V recommendations concerning future EM&V reports contained in the testimony of Public Staff witness Williamson should be approved and applied in future EM&V reports for the applicable EE programs, when feasible and not cost prohibitive, including certain program vintages that remain to be verified and trued up.

Based upon the testimony and evidence cited above, the Commission finds that 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 FINDINGS OF FACT NOS. 12-19

The evidence for these findings of fact can be found in the Initial Testimony and Exhibits of DEP witnesses Miller and Evans, the Supplemental Filing, and the affidavit and exhibits of Public Staff witness Maness.

In her Initial Testimony, as revised by the Supplemental Filing, DEP witness Miller calculated proposed North Carolina retail NLR in the amount of $40,782,610 and a PPI in the amount of $16,807,898 for the EMF component of the total DSM/EE Rider, and North Carolina retail NLR of $20,774,677 and a PPI of $22,371,330 for the forward-looking, or prospective component of the total Rider. Public Staff witness Maness and Company witness Miller (in the Supplemental Filing) indicated that as a result of additional analysis performed by DEP and the agreement reached between DEP and the Public Staff, the Company adjusted its NLR and PPI amounts. The revised exhibits of witness Miller included in the Supplemental Filing indicated that the EMF NLR and PPI amounts were adjusted to $40,220,166 and $16,807,898, respectively, and the prospective NLR and PPI estimates were adjusted to $20,774,677 and $20,271,330, respectively. During the September 19, 2017, hearing, the Public Staff indicated that they agreed with the Company's adjustments in the Supplemental Filing.

In her exhibits filed as part of the Supplemental Filing, DEP witness Miller calculated DEP's total North Carolina retail adjusted test period costs and utility incentives, consisting of its amortized DSM/EE O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI to be $145,464,161. Witness Miller'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 $143,996,006. Therefore, the aggregate DSM/EE under-recovery recommended by DEP for purposes of this proceeding is $1,468,155, as reflected in the Supplemental Filing.

Witness Miller also calculated DEP's estimate of its 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 A&G costs, carrying charges, NLR, and PPI, as $157,162,423.

According to the revised exhibits of DEP witness Miller as filed in the Supplemental Filing, after assignment or allocation to customer classes in accordance with 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	$92,848,553
General Service EE	58,058,006
General Service DSM	5,860,403
Lighting	395,461
Total	$157,162,423

DSM/EE EMF:

Residential	$2,399,583
General Service EE	771,258
General Service DSM	(1,697,547)
Lighting	(5,139)
Total	$1,468,155

Witness Miller'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. The adjusted sales amounts are as follows: Residential class – 15,679,350,211 kWh; General Service EE class – 10,123,944,285 kWh; General Service DSM – 10,075,669,299 class; and Lighting class – 370,385,092 kWh.

According to her revised exhibits filed as part of the Supplemental Filing, witness Miller calculated the DSM/EE billing factors without NCRF as follows:

DSM/EE PROSPECTIVE BILLING FACTORS (cents/kWh):

Residential	0.593
General Service EE	0.573
General Service DSM	0.058
Lighting	0.107

DSM/EE EMF BILLING FACTORS (cents/kWh):

Residential	0.016
General Service EE	0.008
General Service DSM	(0.017)
Lighting	(0.001)

Including the NCRF, the factors calculated by witness Miller are as follows:

DSM/EE PROSPECTIVE BILLING FACTORS (cents/kWh):

Residential	0.594
General Service EE	0.574
General Service DSM	0.058
Lighting	0.107

DSM/EE EMF BILLING FACTORS (cents/kWh):

Residential	0.016
General Service EE	0.008
General Service DSM	(0.017)
Lighting	(0.001)

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 Original and Revised Mechanisms, as applicable, and otherwise adhered to sound ratemaking concepts and principles. The Public Staff's investigation included a review of the Company's 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).

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. None of these topics and issues necessitates an adjustment to the Company's billing factor calculations. With the exception of the items discussed below, which were subsequently corrected by DEP's Supplemental Filing or will be addressed in the Company's next DSM/EE rider filing, witness Maness testified that he believes that the Company has calculated its proposed prospective DSM/EE and DSM/EE EMF billing factors in a manner consistent with 62-133.9, Commission Rule R8-69, and the Original and Revised Mechanisms.

During the course of the Public Staff's review of samples of Vintage Year 2016 program costs, the Public Staff and DEP discovered an exception related to DSM/EE advertising expenses. When these marketing expenses were initially recorded, 35% of the total expense ($70,000) was allocated to DEP's DSM/EE programs. Upon review based on a Public Staff data request, the Company concluded that it had over-allocated costs to DEP's DSM/EE programs, and also not accurately recognized other value received from the vendor. As a result of this conclusion, the Company has indicated it would record an entry in its 2017 DSM/EE program expenses to reduce the 2016 $70,000 allocation by $52,540, to $17,460. The credit correction will be passed through to ratepayers in next year's DSM/EE rider proceeding. Public Staff witness Maness agreed with this correction and the Company's plan for recording it.

The Company also discovered certain errors involving Vintage 2015 NLR related to three programs. The Supplemental Filing sets forth these corrections and revises the Company's proposed billing rates accordingly. At the hearing, the Public Staff indicated that they had reviewed the Supplemental Filing and had no issues with that Supplemental Filing.

Witness Maness noted that in last year's DEP DSM/EE proceeding (Docket No. E-2, Sub 1108) he recommended that the Company be eligible to recover NLR associated with DSDR incurred only up to June 30, 2017, unless such recovery is curtailed earlier by an event such as a general rate case. In this year's proceeding, the Company has requested recovery of approximately $262,000 of Vintage 2016 North Carolina retail NLR associated with DSDR, but none for 2017 (because 2017 is not yet being trued up). Witness Maness indicated that the Public Staff will continue to monitor DSDR NLR in next year's filing.

In the Commission's Sub 1108 Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice, issued on November 15, 2016, Finding of Fact No. 21 states, "It is appropriate for the Public Staff and the Company to make recommendations in the Company's 2017 DSM/EE rider proceeding on the question of whether DEP's 2015 outdoor lighting activities constitute the equivalent of 'net found revenues.' " Public Staff witness Maness noted that during the course of this proceeding, the Company has provided him with workpapers that calculate a net found revenue amount for 2015 of approximately $16,000 (net of negative found revenues). Witness Maness indicated that the Public Staff does not believe that any adjustment to the Company's rates for 2015 net found revenues will be necessary, due to the immateriality of the amount.

As discussed by Public Staff witnesses Williamson and Maness, the Public Staff and DEP had differing interpretations as to the appropriate avoided costs to be used in calculating DEP's DSM/EE rider pursuant to Paragraph 70 of the Revised Mechanism. Paragraphs 69 and 70 of the Revised Mechanism read as follows:

> 69. For the PPI for Vintage Year 2016, the per kW avoided capacity costs used to calculate avoided cost savings shall be the avoided capacity cost rates approved by the Commission for DEP in the most recent biennial avoided cost proceeding as of the date of the filing of the 2015 DSM/EE cost and incentive recovery proceeding. The per kWh avoided energy costs shall be those reflected in or underlying the most recently filed integrated resource plan (IRP).
>
> 70. For the PPI for Vintage Years after 2016, the presumptive per kW avoided capacity costs and per kWh avoided energy costs used to calculate avoided cost savings shall be those determined pursuant to Paragraph 69 above. However, if at the time of initial estimation of the PPI for each vintage year after 2016, either (a) the Company's per kWh avoided energy costs calculated for the purposes of the Company's annual IRP or resource plan update filings have increased or decreased by 20% or more or (b) the Company's per kW avoided capacity costs reflected in the rates approved in the biennial avoided cost proceedings have increased or

decreased by 15% or more, the avoided costs (both energy and capacity) will be updated for purposes of the DSM/EE rider proceeding.

Witness Maness testified that the Public Staff believed that the "ratchet" that would cause avoided capacity and energy costs to be updated for purposes of the DSM/EE rider proceeding had been triggered for purposes of the PPI to be calculated for Vintage Year 2018. The Company's interpretation caused it to believe that the ratchet had not been triggered. Had new avoided cost rates been updated in a manner consistent with the Public Staff's interpretation of Paragraph 70, the Vintage Year 2018 PPI would have been reduced by approximately $3.3 million (approximately 21% of the total estimated 2018 PPI), based on calculations performed by the Company.

Witness Maness indicated that the Public Staff and DEP had reached a comprehensive agreement that resolved their differences regarding Vintage Year 2018 and would change the method used to determine avoided capacity and energy costs on a going forward basis. Pursuant to this agreement, the Company reduced its proposed Vintage Year 2018 PPI by $2,100,000. This reduction to the Vintage 2018 PPI was incorporated in the Supplemental Filing, and was reviewed by the Public Staff as indicated by its statement at the hearing. This same monetary reduction will also be applied to the eventual true-up of the Vintage Year 2018 PPI in future rider proceedings.

With respect to DEP's proposed adjustments to NLR and PPI, the Commission notes that no party opposed such recovery. The Commission finds that such proposed recovery is consistent with the Commission's Orders in Docket No. E-2, Sub 931, and that NLR and PPI are appropriate for recovery in this proceeding, with the prospective rate period costs subject to further review in DEP's future annual DSM/EE rider proceedings. The Commission concludes that DEP has complied with G.S. 133.9, Commission Rule R8-69, and the Commission's Orders in Docket No, E-2, Sub 931, with regard to calculating costs and utility incentives for the test and rate periods at issue in this proceeding. The Commission further concludes that the agreement between the Company and Public Staff to reduce its proposed Vintage Year 2018 PPI by $2,100,000, and to apply this same monetary reduction to the eventual true-up of the Vintage Year 2018 PPI in future rider proceedings, is reasonable and appropriate, and should be approved.

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 $145,464,161. 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 $143,996,006. Therefore, the aggregate DSM/EE under-recovery for purposes of this proceeding is $1,468,155.

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, after incorporation of the NLR and PPI adjustments reflected in the Company's Supplemental Filing and recommended by the Public Staff, is $157,162,423, and this is the appropriate amount to use to develop the DSM/EE revenue requirement.

With regard to the revenue requirements per class, the Commission concludes that after assignment or allocation to customer classes in accordance with 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	$92,848,553
General Service EE	58,058,006
General Service DSM	5,860,403
Lighting	395,461
Total	$157,162,424
DSM/EE EMF:	
Residential	$2,399,583
General Service EE	771,258
General Service DSM	(1,697,547)
Lighting	(5,139)
Total	$1,468,155

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 – 15,679,350,211; General Service Class EE – 10,123,944,285 General Service class DSM – 10,075,669,299; and Lighting class – 370,385,092.

Based on the testimony and exhibits of witnesses Miller and Evans, the affidavit and exhibits of witness Maness, and the entire record in this proceeding, the Commission finds and concludes that the forward-looking DSM/EE rates as proposed by DEP in the Supplemental Filing to be charged during the rate period for the Residential, General Service, and Lighting rate schedules are appropriate. The Commission further concludes that the DSM/EE EMF billing factors as proposed by DEP in the Supplemental Filing are appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

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 on November 16, 2015, in Docket No. E-2, Sub 1070, provided that DEP shall 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 a review of 2015 units showed that no change in the allocation ratio applicable to capacitors was necessary for 2017. The allocation ratio applied to regulators was reduced from 79.45% to 77.79% for 2017. He stated that 2016 units would be reviewed and any changes would be communicated to the Public Staff and implemented on January 1, 2018. The Commission concludes that DEP should 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. 21

The evidence for this finding of fact can be found in the testimony of SACE/NC Justice Center witness Grevatt.

SACE and NC Justice Center witness Grevatt discussed DEP's 2016 energy savings and outlined opportunities for DEP to increase its cost-effective energy savings from both the residential and non-residential sector. In his testimony, witness Grevatt made several recommendations related to enhancement of DSM/EE programs. The Commission concludes that DEP's Collaborative is an appropriate forum for discussion of those recommendations. In particular, the Commission finds that DEP should continue to utilize its Collaborative to discuss and consider the following: (a) the potential for comprehensive program approaches with longer measure lives, such as home retrofits and HVAC system improvements; (b) maximization of cross-program marketing in behavior, audit, and kit programs; (c) opportunities to save more energy in multi-family housing, including in common areas and for commonly-metered systems; (d) expansion of the Company's low income program offerings; (e) ways to continue to promote adoption of a greater range of measures through the Company's Small Business Energy Saver Program; (f) ways to encourage participation of non-residential customers who are eligible to opt out, including making sure that the available programs meet these customers' needs and by providing personalized outreach to engage them; and (g) use of Advanced Metering Infrastructure (AMI) technology to drive greater efficiency for DEP customers.

Witness Grevatt also noted in his testimony that DEP's 2016 energy savings fell short of the system-wide EE savings target that DEP agreed to in a settlement agreement with SACE, the South Carolina Coastal Conservation League, and the Environmental Defense Fund in connection with the then-proposed merger of Duke Energy and Progress Energy. In addition, he noted that DEP's projected energy savings for 2017 and 2018 are also expected to fall below the EE savings targets, remaining flat in 2017 and declining in 2018. Based on the testimony of SACE and NC Justice Center witness Grevatt, the Commission finds that DEP should continue to utilize its

Collaborative to discuss and consider ways in which it can meet the target of annual energy savings of at least 1% of prior-year retail sales[1] and cumulative savings of at least 7% over the period from 2014 through 2018.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence in support of this finding and conclusion can be found in the testimony of DEP witnesses Evans and Duff and Public Staff witnesses Hinton and Williamson, and the affidavit of Public Staff witness Maness.

As discussed previously, Public Staff witness Maness testified that following the filing of DEP's application in this docket, the Public Staff and DEP reached a comprehensive agreement regarding the amount of the PPI for this proceeding, as well as proposed revisions to the Revised Mechanism dealing with how applicable avoided costs will be determined on a going-forward basis. These recommended revisions are set out in Maness Exhibit II.

Revision to Mechanism Paragraph 70

Public Staff witness Maness stated that the first proposed revision was to Paragraph 70 of the Mechanism, which sets out how the avoided costs are determined for purposes of calculating the PPI. Under current Paragraph 70, avoided energy costs are derived from those calculated for the purposes of the Company's annual integrated resource plan (IRP) or resource plan update filings. Witness Maness noted that avoided capacity costs for PPI calculation are derived from the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases. As discussed previously, changes in the avoided costs used for PPI purposes occur only when certain ratchets have been tripped. Under the recommended revised language of Paragraph 70, 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 will be used to derive both the PPI-focused avoided capacity and energy costs (hereinafter, the "PURPA method") effective for Vintage Year 2019 and thereafter. However, Public Staff witness Maness explained that DEP and the Public Staff have also agreed that the Public Staff may propose further revisions to the Mechanism related to the use of the PURPA method of determining avoided costs should the methodologies adopted to determine avoided costs in the Biennial proceedings

[1] As the Commission noted in its Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice issued August 25, 2016, in Docket No. E-7, Sub 1105, to the extent that non-residential customers opt out of the Company's programs and implement their own DSM/EE programs, that does not count toward achievement of the aspirational targets. Thus, while the retail electricity sales that the 1% goal is based upon include sales to customers who have opted out of paying the DSM/EE rider, the level of savings the Company is able to achieve is negatively impacted by the ability of certain non-residential customers to opt out of the DSM/EE rider.

change in a manner that conflicts with their use in the DSM/EE context, including possibly the adoption of the "two-year refresh" proposal of the Company in Docket No. E-100, Sub 148. In regard to the two-year refresh, witness Hinton testified that two-year fixed avoided energy rates would add a degree of uncertainty and risk to the planning and development of new DSM/EE programs.[1]

Public Staff witness Hinton's testimony provided a history of the percentage changes in the Company's IRP-based avoided costs, which had triggered an update of DEP's avoided costs pursuant to Paragraph 70 in its current form. Witness Hinton also discussed the differences between using IRP-based avoided costs, as required under Paragraph 70 in its current form, and PURPA-based costs, as proposed in the revision to Paragraph 70. He explained that the IRP incorporates a System Optimizer capacity planning model that develops least cost integrated plans while satisfying reserve criteria, while PURPA proceedings incorporate the PROSYM model, an hourly chronological production cost model that incorporates more detailed generating unit characteristics such as the costs to start and shut down units, unit ramp rates, and unit minimum up and down times. A second significant difference in the two methodologies is that the cost of carbon emissions is included in IRP avoided costs and excluded from PURPA avoided costs. Witness Hinton noted that a third difference is that the IRP is mainly a planning tool, while the PURPA proceeding is a where the cost inputs are more closely scrutinized. Finally, he advocated the use of PURPA-based avoided costs in the DSM/EE Mechanism because it would link the savings and financial incentives afforded the Company for its DSM/EE programs with the rates it pays QFs for avoided energy and avoided capacity. He stated his belief that the use of PURPA-based avoided energy and capacity costs would lead to better estimates of the costs avoided by the Company's DSM/EE programs and provide a more accurate view of the value of DSM and EE. For illustrative purposes, Public Staff witness Hinton also provided a graph of DEP's 2015 and 2016 IRP-based avoided energy costs along with DEP's 2014 PURPA-based avoided energy costs and recommended that the Commission approve the future use of PURPA-based avoided energy costs.

Witness Hinton further testified that the Company's avoided transmission and distribution (T&D) cost is appropriate for this proceeding; however, the costs should be updated for the 2019 DSM/EE rider proceeding.

[1] On October 11, 2017, in its Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued in Docket No. E-100, Sub 148, the Commission declined to adopt the Company's "two-year refresh" proposal.

Revision to Mechanism Paragraph 18

Public Staff witness Maness testified that the second proposed revision to the Mechanism would specify the avoided costs to be used for purposes of program approval. The current Mechanism does not specify which avoided costs should be used, but the Company has typically used the avoided costs it used in the most recent annual DSM/EE Rider filing. He explained that DEP and the Public Staff have agreed to revise Revised Mechanism Paragraph 18 to specifically require use of the "PURPA method" for the purpose of program approval filings. The specific Biennial Determination used for each program approval filing would be the one most recently approved by the Commission as of the date of the program approval filing.

Public Staff witness Williamson testified that the approach to cost-effectiveness for program approval should be consistent with the approach employed for ongoing cost-effectiveness evaluated in annual DSM/EE rider proceedings. He explained that the evaluation for program approval is typically based on a short-term projection of costs and participation, as there is greater uncertainty in the projections beyond five years. However, the evaluations incorporate the savings impacts of the measures over the life of the measure, which could be well beyond five years. Witness Williamson stated that the Public Staff believes that it is reasonable for the avoided costs used for a program approval to come from the most recent approved avoided cost proceeding.

Revision to Paragraph 22 and Addition of Paragraphs 22A-D

Witness Maness stated that the third revision to the Mechanism proposed by the Public Staff and DEP was 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 22 of the Mechanism, each year the Company files an analysis of the current cost-effectiveness of each of its DSM/EE programs as part of the DSM/EE Rider filing. Consistent with the revisions recommended for Paragraph 70, DEP and the Public Staff propose a new Paragraph 22A to require the use of the "PURPA method" for determining the avoided costs used in the determination of continued cost-effectiveness for each program. Also like Paragraph 70, Paragraph 22A specifies that the PPI-focused avoided capacity and energy costs will be derived from the avoided costs underlying 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.

Witness Maness indicated that new Paragraphs 22B through 22D address the steps that will be taken if specific DSM/EE programs continue to produce Total Resource Cost Test results less than 1.00 for an extended period. Previously, provisions of this type have been handled solely on a case-by-case basis.

Public Staff witness Williamson explained that the proposed revisions to Paragraph 22 and the addition of Paragraphs 22A-D set out a process that provides timeframes for DEP to either modify or close programs that are not cost-effective. For any program that initially demonstrates a TRC of less than 1.00, the Company will 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. Witness Williamson testified that if a program demonstrates a prospective TRC of less than 1.00 in a third DSM/EE rider proceeding, the Company would terminate the program effective at the end of the year following the DSM/EE rider order, unless otherwise ordered by the Commission.

Reservation of Right to Address PPI Percentage in Later Proceeding

Finally, witness Maness testified that the comprehensive agreement reached by the Public Staff and DEP allowed the Public Staff to reserve the right to potentially address any changes to the PPI percentage in a future proceeding. Pursuant to Paragraph 67 of the Mechanism, the PPI for each vintage year is calculated by multiplying the present value of the estimated net dollar savings associated with the DSM/EE portfolio installed in that vintage year by a factor of 11.75%. Witness Maness explained that this percentage should remain subject to periodic change to ensure that the bonus incentive it provides to the utility remains fair and reasonable. While the Public Staff is not proposing a change in the PPI percentage in this proceeding, DEP has agreed to recognize the Public Staff's reservation of the right to propose changes to the percentage in a future proceeding. Witness Maness noted that the Public Staff and the Company expect that filings on mechanism revisions will be made in late 2018 or early 2019, with any changes effective starting with Vintage Year 2020.

DEP witness Duff testified that the comprehensive agreement reached by DEP and the Public Staff improves upon the methodology used to calculate avoided costs under the Revised Mechanism and is good for customers because it will reduce the potential for the avoided costs used to assess program cost-effectiveness and establish DEP's PPI from becoming dated, while still allowing DEP enough certainty to effectively plan its portfolio of programs. He noted that under the current Revised Mechanism, if the trigger thresholds were not hit, avoided cost rates could potentially remain unchanged for years. Under the proposed modifications to the Mechanism, DSM and EE programs will be evaluated for cost-effectiveness using Commission-approved avoided cost rates that are generally updated every two years. Another benefit to customers is that it aligns the avoided energy and avoided capacity costs used for DSM/EE with those approved in the Company's biennial avoided cost proceeding, avoiding a potential mismatch that could undermine the validity of the cost-effectiveness evaluation. DEP witness Duff also pointed out that the proposed revisions created a clear protocol for the Company to address programs that are struggling to maintain cost-effectiveness, giving the Company time to manage the program and improve its cost-effectiveness, if possible, while also creating a specific timeline to ensure that a non-cost-effective program that does not have the potential to improve does not continue to unnecessarily add costs to the DSM/EE rider. Finally, he noted that the proposed DEP revisions are the same in all material respects to the revisions to Duke Energy Carolinas, LLC's (DEC) DSM/EE cost recovery mechanism that were proposed by the Public Staff and DEC, and approved by the Commission, in Docket No. E-7, Sub 1130. He explained that approval of the requested revisions thus would further the goal of aligning the two companies' cost recovery mechanisms and would make the Commission's and other parties' reviews of the companies' annual rider filings more streamlined. Witness Duff concluded that the agreement is in the public interest and should be accepted by the Commission as a fair and reasonable resolution of the issues in this proceeding.

The Commission further concludes that the revisions to the Revised Mechanism proposed by the Public Staff and DEP are appropriate and in the public interest, and should be adopted. First, the revision to Paragraph 70 removes any ambiguity regarding the proper avoided costs to be used for calculating the PPI. The Commission finds that the revision to Paragraph 70 better links the savings and financial incentives for DEP's DSM/EE programs with the rates it pays QFs for avoided energy and avoided capacity, and provides for regular updating to prevent stale or outdated rates. Further, the Commission finds that the revision to Paragraph 18, which specifies the avoided costs to be used in calculating cost-effectiveness in program approvals, is appropriate and should be adopted. Likewise, the revisions to Paragraph 22 and the proposed Paragraphs 22A-D are appropriate for specifying the avoided costs to be used in calculating ongoing cost-effectiveness, as well as setting out a procedure for modification or closure of programs that are no longer cost-effective. Finally, the Commission recognizes the right of any party to propose further modifications to the Revised Mechanism in future proceedings, including the Public Staff's right to revisit the PPI percentage. Therefore, the Commission adopts the revisions to the Mechanism as set out in Maness Exhibit II to be effective January 1, 2018.

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 increments of: 0.016 cents per kWh for the Residential class; 0.008 cents per kWh for the EE component of General Service classes; decrements of (0.017) cents per kWh for the DSM component of General Service classes, and (0.001) cents per kWh for the Lighting class. These DSM/EE EMF billing factors do not change when the NCRF is 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 increments of 0.593 cents per kWh for the Residential class; 0.573 cents per kWh for the EE component of General Service classes; 0.058 cents per kWh for the DSM component of General Service classes; and 0.107 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 of 0.140%, are increments of: 0.594 cents per kWh for the Residential class; 0.574 cents per kWh for the EE component of the General Service classes; 0.058 cents per kWh for the DSM component of the General Service classes; and 0.107 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 of 0.140%) for the Residential, General Service, and Lighting rate classes are increments of 0.610 cents per kWh for the Residential class, 0.582 cents per kWh for the EE portion of the General Service classes, 0.041 cents per kWh for the DSM portion of the General Service classes, and 0.106 cents per kWh for the Lighting class.

4. That DEP shall file appropriate rate schedules and riders with the Commission in order to implement these adjustments as soon as practicable. Such rates are to be effective for service rendered on or after January 1, 2018.

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 Commission hereby approves and adopts the revisions to the Revised Mechanism as set out in Maness Exhibit II to be effective January 1, 2018.

7. That the Company will provide an update to its avoided T&D costs for the 2019 DSM/EE rider proceeding.

8. That the Appliance Recycling Program shall be canceled as of December 31, 2017.

9. That in its next DSM/EE rider filing, DEP should address the continuing cost-effectiveness of the Smart $aver Performance (Custom) Program, Smart $aver Performance (Prescriptive) Program, the Smart $aver Performance Incentive Program and the Home Energy Improvement Program.

10. That with respect to the Smart $aver Performance (Custom) Program and the Smart $aver Performance (Prescriptive) Program, the Company should include a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program(s) in its next DSM/EE rider filing.

11. That if the Commission-approved modifications to the Residential Home Energy Improvement Program do not maintain or improve the program's cost-effectiveness by the Company's next DSM/EE rider proceeding, the program should be terminated at the end of 2018.

12. That the EM&V reports for the Small Business Energy Saver Program (Evans Exhibit D) and the Multi-Family EE Program (Evans Exhibit E) should be revised as discussed by Public Staff witness Williamson and refiled in the next rider proceeding and their respective program approval dockets.

13. That the Company should, when feasible and not cost prohibitive, incorporate the recommendations made by Public Staff witness Williamson regarding EM&V into future EM&V reports filed with the Commission in subsequent DSM/EE rider proceedings.

14. That the issues raised in witness Grevatt's testimony shall be discussed in the DEP Collaborative as addressed herein, and the results of such discussions shall be reported in the Company's application in the next DSM/EE rider proceeding.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of November, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

ONE-HUNDRED SEVENTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

Volume II

ISSUED FROM
JANUARY 1, 2017 THROUGH DECEMBER 31, 2017

ONE-HUNDRED SEVENTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2017, through December 31, 2017

Edward S. Finley, Jr., Chairman

Bryan E. Beatty, Commissioner

ToNola D. Brown-Bland, Commissioner

* Don M. Bailey, Commissioner

Jerry C. Dockham, Commissioner

James G. Patterson, Commissioner

Lyons Gray, Commissioner

* Daniel G. Clodfelter, Commissioner

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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.

* Daniel G. Clodfelter, appointed July 1, 2017, replacing Don M. Bailey

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DOCKET NO. EMP-92, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of NTE Carolinas II, LLC, for a Certificate of Public Convenience and Necessity to Construct a 500-MW Natural Gas-Fueled Merchant Power Plant in Rockingham County, North Carolina	)))))	ORDER GRANTING CERTIFICATE WITH CONDITIONS

HEARD ON: Tuesday, October 25, 2016, at 7:00 p.m., at the Rockingham County Courthouse, Superior Courtroom A, 170 Highway 65, Reidsville, North Carolina, and

Wednesday, November 2, 2016, 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; Commissioner Bryan E. Beatty and Commissioner James G. Patterson

APPEARANCES:

For NTE Carolinas II, LLC:

M. Gray Styers, Jr., Smith Moore Leatherwood, LLP, 434 Fayetteville Street, Suite 2800, Raleigh, North Carolina 27601

For North Carolina Waste Reduction and Awareness Network:

John D. Runkle, 2121 Damascus Church Road, Chapel Hill, North Carolina 27516

For the Using and Consuming Public:

Dianna W. Downey, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On July 29, 2016, NTE Carolinas II, LLC (NTE), a wholly-owned first-tier subsidiary of NTE Carolinas II Holdings, LLC, and an affiliate of NTE Energy, LLC (NTE Energy), filed an application pursuant to G.S. 62-110.1(a) and Commission Rule R8-63 for a certificate of public convenience and necessity (CPCN or certificate) authorizing the construction and operation of an approximately 500-megawatt (MW) natural gas-fueled generating facility in Rockingham County, North Carolina, to be known as the Reidsville Energy Center (Facility). On the same date, NTE pre-filed the direct testimony of Michael C. Green, Vice-President, in support of the application.

On August 10, 2016, the Public Staff-North Carolina Utilities Commission filed a Notice of Completeness stating that the Public Staff had reviewed the application, as required by Commission Rule R8-63(d), and that the Public Staff considered the application to be complete. In addition, the Public Staff requested that the Commission issue a procedural order setting the application for hearing, requiring public notice pursuant to G.S. 62-82, and addressing other procedural matters.

On August 16, 2016, the Commission issued an order setting the application for hearing, requiring NTE to provide appropriate public notice, establishing deadlines for the filing of petitions to intervene, intervenor testimony, and rebuttal testimony, and requiring the parties to comply with certain discovery guidelines.

On September 21, 2016, NTE filed a letter amending the application to add approximately eighty (80) acres of property as a part of the project site. In addition, NTE filed an updated map showing the new acreage. By Order dated September 23, 2016, the Commission amended the Public Notice to reflect the additional acreage of the project site and required that the amendment to the application be submitted 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 amended application.

On September 30, 2016, the Clearinghouse Coordinator of the Office of Policy and Planning of the Department of Administration filed comments with the Commission concerning the original application stating that because of the nature of the comments, no further review is needed by the Commission to determine compliance with the North Carolina Environmental Policy Act.

On October 5, 2016, the North Carolina Waste Awareness and Reduction Network (NC WARN) filed a motion to intervene, which was granted by Order issued on October 7, 2016. On October 11, 2016, NTE filed a motion asking the Commission to reconsider its Order granting NC WARN's motion to intervene and objected to the intervention of NC WARN.

On October 17, 2016, the Commission disposed of NTE's motion for reconsideration by treating it as a timely objection to the motion to intervene and denied NTE's objection to NC WARN's intervention.

On October 18, 2016, the Public Staff filed the testimony of Dustin R. Metz, an engineer in the Electric Division of the Public Staff. On October 19, 2016, NC WARN filed the testimony of William E. Powers, the principal of Powers Engineering in San Diego, California.

On October 25, 2016, the Commission conducted a public witness hearing at the Rockingham County Courthouse in Reidsville, North Carolina, as provided in the Commission's August 16, 2016 Order and in the published notice, for the purpose of receiving public witness testimony regarding NTE's application. Sixteen public witnesses spoke at the hearing.

On October 26, 2016, NTE filed a motion to strike certain portions of witness Powers' testimony and a motion in limine requesting that testimony, arguments, and cross-examination be limited to relevant issues. These motions were denied by Order issued November 1, 2016.

On October 27, 2016, an Affidavit of Publication prepared by the Rockingham County Advertising Sales Manager of the Greensboro News & Record was filed on behalf of NTE indicating that NTE had caused publication of public notice as required by the Commission's August 16, 2016 and September 23, 2016 Orders. On the same date, NTE filed the rebuttal testimony of Michael C. Green.

On November 1, 2016, the State Clearinghouse filed a response to the amended application stating that because of the nature of the comments, no further review is needed by the Commission to determine compliance with the North Carolina Environmental Policy Act.

Also on November 1, 2016, NTE filed the affidavit of Michael C. Green responding to issues raised at the public witness hearing on October 25, 2016.

On November 2, 2016, the Commission held the expert witness hearing as scheduled for the purpose of receiving the expert testimony of the parties.

On December 1, 2016, NTE filed two late-filed exhibits, as requested by the Commission at the expert witness hearing.

On December 22, 2016, NC WARN filed a post-hearing brief.

Also on December 22, 2016, NTE and the Public Staff filed a joint proposed order.

Based on the testimony presented at the hearings and the entire record of this proceeding, including matters of which judicial notice has been taken, the Commission makes the following:

FINDINGS OF FACT

1. NTE is organized under the laws of the State of Delaware with its principal place of business in St. Augustine, Florida, and it is authorized to do business in North Carolina.

2. NTE's affiliate, NTE Energy, plans to develop, construct, own, acquire, and operate independent power plants in the competitive wholesale markets in the United States. NTE Energy companies recently closed financing and began construction on two projects totaling 950 MW of capacity and involving approximately $1.25 billion in financing. One of those projects is the 475-MW Kings Mountain Energy Center, the construction of which was approved by the Commission's issuance of a CPCN in Docket No. EMP-76, Sub 0 on October 28, 2014.

3. In compliance with G.S. 62-110.1(a) and Commission Rule R8-63, NTE properly filed with the Commission an application for a CPCN authorizing the construction and operation of an approximately 500-MW natural gas-fueled electric generation plant to be located in Rockingham County, North Carolina.

4. The proposed Facility will be located on approximately 20 acres of an approximately 170-acre site in Rockingham County, with the majority of the site being bounded by North Carolina Highway 65 to the east and New Lebanon Church Road to the west.

5. The Facility will be constructed as a one-on-one combined cycle electric generating facility and will consist of one combustion turbine generator; one heat recovery steam generator; and one steam turbine generator. Natural gas will be the only fuel burned by the combined cycle unit, consuming about 95,000 MMBtu/Day to operate at full output.

6. Construction of the Facility is anticipated to begin in the first quarter of 2018, with commercial operation scheduled to begin as early as the fourth quarter of 2020, with an expected service life of 30 years.

7. Commission Rule R8-63(e) provides that a certificate shall be subject to revocation if any of the federal, state, or local licenses or permits required for construction and operation of the generating facility are not obtained or, having been obtained, are revoked.

8. In accordance with Commission Rule R8-63(b)(2)(v), NTE's application included a Table of Permits and Approvals, which listed the federal, State, and local permits and approvals required for the Facility and the status of those permits and approvals.

9. The granting of the CPCN in this proceeding should be conditioned upon the requirement that the Facility shall be constructed and operated in strict accordance with applicable laws and regulations, including any local zoning and environmental permitting requirements.

10. The CPCN should also be conditioned upon NTE's abstaining from attempting to exercise any power of eminent domain under North Carolina law related to the Facility and NTE's application.

11. In addition, the grant of a CPCN in this docket should be conditioned upon the requirement that the CPCN holder, and all future holders of the CPCN, will obtain the approval of the Commission before selling, transferring, or assigning the CPCN and/or generating facility to an unaffiliated third-party. Any other planned sale, transfer, or assignment of the CPCN and/or generating facility is subject to Commission action as appropriate pursuant to Commission Rule R8-63(e)(4).

12. The required regulatory permits and approvals and conditions imposed by the Commission for the construction of the Facility are sufficient to ensure that the environmental concerns raised by NC WARN and members of the public are satisfied.

13. NTE has made a sufficient showing of need for the proposed Facility. Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP), each show a need for approximately 5,000 MW of additional generating capacity due to load growth and planned retirements over the next 15 years. In addition, based on NTE's assessments and investigation of market activity by regional load-serving entities, NTE has identified specific wholesale customers interested in purchasing the output of the proposed Facility.

14. NTE's proposed merchant plant will be financed by private companies, rather than ratepayers. Under this approach, if assets become stranded, the owner will face the financial consequences, not captive North Carolina retail electric customers. Thus, the construction costs of the Facility will not qualify for inclusion in, and will not be considered in a future determination of the rate base of a public utility pursuant to G.S. 62-133, and construction of the Facility creates no financial risk to North Carolina retail electric customers.

15. It is reasonable, appropriate and serves the public interest to grant the requested CPCN to NTE, as conditioned herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

These findings of fact are essentially informational, procedural, or jurisdictional in nature, pertain to the identity of the applicant, and are not in dispute. They are supported by the application and the exhibits thereto and the pre-filed testimony of NTE witness Green and public witness Nick Hendricks.

NTE's verified application stated that NTE's affiliate, NTE Energy, plans to develop, construct, own, acquire, and operate independent power plants in the competitive wholesale markets in the United States. NTE Energy companies recently closed financing and began construction on two projects totaling 950 MW of capacity and involving approximately $1.25 billion in financing. One of these is the 475-MW Kings Mountain Energy Center (KMEC) in Kings Mountain, North Carolina, for which the Commission issued a CPCN to NTE Carolinas, LLC, in Docket No. EMP-76, Sub 0, on October 28, 2014. The other is a 475-MW natural gas-fueled combined cycle facility in Middletown, Ohio.

NTE Witness Green testified that the KMEC site is under construction, and the construction is on schedule. All piles have been installed, the heat recovery steam generator (HRSG) and exhaust stack foundations have been placed, the combustion turbine generator (CTG), and steam turbine generator (STG) foundations are being formed, and rebar has been installed. Concrete placement for the CTG foundation has recently begun. Excavation for underground water, fuel gas, instrument air, drain piping, and the duct bank is ongoing. The fabrication, installation and backfilling of equipment for the process water, fuel gas, fire water, and raw water pipes, as well as the oily water drains, and the pipe systems for instrument air and hydrogen are ongoing. Mitsubishi Hitachi Power Systems Americas, Inc., has begun fabrication of the CTG, Toshiba America Energy Systems Corporation has begun fabrication of the STG, and Vogt Power International, Inc. has begun fabrication of the HRSG.

At the public witness hearing, Mr. Nick Hendricks, the Assistant City Manager of the City of Kings Mountain, testified regarding his experiences with NTE and its Kings Mountain facility over the past three years. He stated that NTE has worked diligently with the city and county to address issues arising from that facility, and stated that "we are very impressed with what we have seen so far." (T Vol.1, p. 34) He also noted that NTE has been heavily involved in the community and is a good corporate citizen of Kings Mountain. Witness Green testified that the same management team for the Kings Mountain facility would be involved in the development and construction of the Rockingham County Facility.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-6

These findings are supported by the application and the testimony of NTE witness Green and Public Staff witness Metz.

North Carolina General Statute 62-110.1 and Commission Rule R8-63 provide that no person may begin construction of a facility for the generation of electricity to be directly or indirectly used for furnishing public utility service without first obtaining from the Commission a certificate that the public convenience and necessity requires or will require such construction. The Public Staff notified the Commission on August 10, 2016, that it considered the application of NTE to be complete. An examination of the application, the exhibits attached thereto, and the testimony of the witnesses confirms that NTE has complied with all filing requirements of the statute and the Commission's merchant plant certificate rule.

According to the application and the testimony of witness Green, the CPCN application in this docket, similar to the approved facility in Kings Mountain, is for an approximately 500-MW natural gas-fueled electric generation plant to be located in Rockingham County, North Carolina. The Facility will be located on approximately 20 acres of an approximately 170-acre site in Rockingham County. As proposed, the Facility will be constructed as a one-on-one combined cycle electric generating facility and will consist of one combustion turbine generator; one heat recovery steam generator; and one steam turbine generator. Construction is anticipated to begin in the first quarter of 2018, with commercial operation scheduled to begin as early as the fourth quarter of 2020, with an expected service life of 30 years.

Natural gas will be the only fuel burned by the Facility, requiring up to 95,000 MMBtu/Day to operate at full output. Transcontinental Gas Pipe Line Company, LLC (Transco), has existing interstate pipelines crossing the Facility site to which the Facility will be connected via an approximately 650 feet long lateral. NTE anticipates that Piedmont Natural Gas Company, Inc., the local distribution company serving Rockingham County, will construct, own, maintain, and be responsible for compliance testing on the lateral under a special purpose tariff.

Witness Metz testified that NTE had complied with the Commission's filing requirements, noting that the Public Staff had notified the Commission to that effect by its filing on August 10, 2016.

Based upon the foregoing, the Commission finds and concludes that NTE has filed a complete and sufficient application for a CPCN in accordance with the requirements of G.S. 62-110.1(a) and Commission Rule R8-63.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-12

The evidence supporting these findings is found in the application, the testimony of Public Staff witness Metz, the witnesses testifying at the public hearing, the testimony of NTE witness Green, the affidavit of NTE witness Green filed on November 1, 2016 (Green Affidavit), the testimony of NC WARN witness Powers, and the record as a whole.

As required by Commission Rule R8-63(b)(2)(v), Attachment 6 of NTE's application contained a list of all federal, State, and local permits and approvals related to the Facility and the status of the permits and approvals. As noted in the Green Affidavit, the electric generation facility proposed by NTE in this docket is subject to the regulatory jurisdiction of many local, state, and federal agencies and bodies, each of which has requirements and or permits applicable to various aspects of the Facility. NTE must comply with all of those regulations in order to develop, finance, construct, and operate the Facility. Each of the governmental agencies and bodies has specific areas and issues that it regulates. Commission Rule R8-63(e) states that a certificate shall be subject to revocation if federal, state, or local licenses or permits are not obtained or are revoked, and Commission Rule R8-63(f) requires annual reports, which should include the status of necessary licenses or permits.

In the Green Affidavit, witness Green stated under oath that at the local level, NTE was required to obtain a Special Use Permit from Rockingham County in order to comply with local zoning requirements. On July 11, 2016, the Rockingham County Planning Board conducted a quasi-judicial public hearing on the requested Special Use Permit for the Facility (Special Use Permit Case #2016-006). During the course of that hearing, it was noted that the Facility will be located next to an existing 874-MW power plant (the Duke Rockingham plant) that has been there for about 20 years, and that there is a large compressor station on the Williams Gas Pipeline approximately one mile to the north of NTE's proposed Facility. As required by the Rockingham County Unified Development Ordinance, the Planning Board made the following findings, based upon the competent, material, and substantial evidence presented under oath at that hearing on the Special Use Permit: (a) That the use or development is located, designed, and proposed to be operated so as to maintain or promote the public health, safety, and general welfare; (b) That the use or development complies with all required regulations and standards of this ordinance [Rockingham County Unified Development Ordinance] and with all other applicable regulations; (c) That the use or development is located, designed, and proposed to be operated so as to maintain or enhance the value of contiguous property; and (d) That the use or development conforms with the general plans for the land use and development of Rockingham County as embodied in the Unified Development Ordinance and in the Rockingham County Land Use Plan. A motion to approve the permit specifically recited these four findings of fact as the basis of approval, and the permit was approved unanimously by the seven-member Rockingham County Planning Board.

The findings of the local government planning board are informative to the Commission's deliberations of public convenience and necessity. In addition to the granting of the Public Use Permit, local governmental support of the Facility is demonstrated by the testimony of Mr. Ken Allen, Business and Economic Developer for Rockingham County, who spoke in favor of the project, noting that the Facility will significantly increase the County's tax base, create approximately 15 to 20 full-time jobs after construction, and approximately 200 to 300 construction jobs. Mr. Ronnie Tate, Director of Engineering and Public Utilities for Rockingham County, also testified that his department supported both the Facility and a mutually beneficial agreement between NTE and the County allowing for the expansion of county services.

The Commission received public witness testimony at the public hearing in the Rockingham County Courthouse on October 25, 2016. Sixteen persons made direct statements, some for and some against the proposed project. The majority of individuals spoke against the proposed project stating concerns regarding the need for the project, property values, noise and water issues. NC WARN emphasized the concerns expressed at the public hearing in its post-hearing Brief filed on December 22, 2016. In addition, thirty seven consumer statements of position were filed with the Commission. The statements generally dealt with the same concerns expressed in the public hearing. The Commission is sensitive to the issues expressed by the public witnesses and in the consumer statements of position. However, the Commission finds that these issues were directly addressed by the necessary findings of the Rockingham County Planning Board in its determination granting the required Special Use Permit. The Special Use Permit, filed in this docket as Appendix B to the Green Affidavit, also contains specific conditions to ensure development in accordance with the site plan, compliance with all required permits and approvals, approval by the North Carolina Department of Transportation of the driveway permit, and that all applicable local ordinance requirements for public utility facilities are met.

While some concerns were expressed about the quantity of water to be used by the Facility, it was undisputed, and confirmed by a letter from Mr. Ronnie Tate (attached as Appendix A to the Green Affidavit), that the County will permit, own, operate and maintain the new water infrastructure that includes both the supply lines that bring water from the Dan River to NTE's Facility and the discharge lines returning water from the Facility to the river, as well as the intake and discharge structures. As stated in the Green Affidavit, the County will be required to comply with all federal, state, and local permitting requirements to ensure that the locations of the intake and discharge structures are compatible with the river, that the route of the piping is acceptable, and that the intake structure pumps will comply with the County noise ordinance. Specifically, the design of the intake structure, intake flows, discharge structure and discharge flows will have to meet all requirements of sections 316(b), 401, and 404 of Title 40, Code of Federal Regulations (40 CFR), as reviewed and administered by the North Carolina Department of Environmental Quality and the United States Army Corps of Engineers.

With respect to public witness concerns about noise levels at the Facility, witness Green stated in his Affidavit that NTE will meet the requirements of all applicable Rockingham County noise ordinances. He further noted that NTE recently obtained an option to acquire an additional 74 acres, bringing the project site to a total of 170 acres. Witness Green further stated that the Facility's power block will be located on about 20 acres within the 170 acres total, which NTE believes will ensure that the Facility has a minimal impact on ambient noise levels. Finally, witness Green stated that NTE is willing to meet with interested residents to discuss their concerns about the Facility's effects on residents. The Commission views NTE's acquisition of additional buffer property and its willingness to meet with residents to be important commitments that demonstrate NTE's intent to be a responsible neighbor.

In response to public witness concerns about potential impact on historic sites, witness Green stated in his Affidavit that NTE hired expert consultants who have already performed archeological, historical and cultural resource reviews and field surveys. Those results were provided to the State Historic Preservation Office (SHPO) for review. The site was recommended as ineligible for inclusion on the National Register of Historic Places (NRHP), and no further work was recommended. SHPO concurred with these recommendations and further agreed that no sites deemed eligible for the NRHP would be impacted by the proposed undertaking.

NC WARN stated in its post-hearing Brief that one of the reasons the Commission should deny the NTE application is NTE's natural gas plant will contribute to climate change from methane leakage and venting throughout the natural gas production and distribution cycle at a greater rate than DEC's systemwide methane impacts. Witness Powers testified about his concerns about the environmental impacts of the Facility. He testified that natural gas-fired power generation has a substantially greater greenhouse gas (GHG) emission footprint than previously understood. He also opined that when methane leakage emissions associated with natural gas production and transport are included, the total GHG footprint of the combined cycle plant increases substantially. The total GHG footprint of DEC grid power increases at a much more modest rate when methane emissions are included, as natural gas combustion accounts for only 11 percent of DEC's 2015 power mix. He further testified that under any methane leakage scenario, the total GHG footprint from the NTE Facility will be substantially above the total GHG footprint of DEC grid power. In support of his assertions, witness Powers provided Attachment A to his testimony, which contained calculations and the assumptions underlying his assertions. However, on cross-examination, witness Powers admitted that he did not use any specific characteristics of the Facility in preparing Attachment A and had not reviewed the air permit application filed with the State's Department of Environmental Quality.

The Commission gives little weight to witness Powers' testimony that the proposed NTE Facility would have a GHG footprint (lb/MWh) greater than the total GHG footprint of DEC's grid power. The sources of base load energy to the DEC grid are primarily nuclear and coal. Nuclear energy results in a GHG footprint that is considerably less than that of natural gas. The Commission understands that the proposed Facility may enter into contracts to serve existing DEC wholesale customers and, therefore, displace generation from existing DEC plants (coal and natural gas, but not nuclear). Therefore, there could be some additional GHGs released in the first few years of the proposed plant's operation compared to DEC's footprint without the plant in service. The Commission concludes, however, that there is no substantial evidence that granting the CPCN is likely to impact, in any measurable degree, methane emissions from natural gas wells or transmission facilities.

In addition, the Commission gives substantial weight to the results filed herein by the State Clearinghouse. The State Clearinghouse provided its comments in review of the original application and the amended application. In both instances, the Clearinghouse determined that no further State Clearinghouse review action is needed for compliance with the North Carolina Environmental Policy Act.

Further, witness Metz testified that the Public Staff does not have particular expertise in the area of the impacts of electric generation on the environment. He testified that 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 plants. To that end, he recommended that the CPCN be granted subject to the following conditions: (1) the Facility shall be constructed and operated in strict accordance with applicable laws and regulations, including any environmental permitting requirements; (2) NTE will not assert that issuance of the CPCN in any way constitutes authority to exercise the power of eminent domain, and it will abstain from attempting exercise such power; and (3) the CPCN shall be subject to Commission Rule R8-63(e) and all orders, rules and regulations as are now or may hereafter be lawfully made by the Commission.

The Commission finds and concludes that the conditions recommended by witness Metz should be adopted and that they are sufficient to address the concerns raised by NC WARN. Witness Metz recommended that the CPCN granted to NTE be subject to a requirement that the Facility be constructed and operated in strict accordance with all applicable laws and regulations, including any environmental permitting requirements. In addition, the Rockingham County Planning Board has conducted a public hearing for NTE's requested special use permit for the Facility and approved the zoning permit, making specific findings of fact and placing certain conditions on the permit. Other issues, such as water use and archaeological concerns, will be dealt with by permitting requirements that apply to the Facility. The Commission has considered the testimony of witness Powers but concludes that environmental concerns regarding the Facility are appropriately addressed by the imposition of the conditions recommended by the Public Staff. In addition, the required regulatory approvals and conditions for the Facility are sufficient to address the environmental concerns raised by NC WARN and members of the public.

With respect to the other conditions recommended by Public Staff witness Metz in addition to the environmental protection conditions, the Commission concludes that these conditions also should be imposed. Accordingly, the Commission concludes that any CPCN approved in this docket should be conditioned upon NTE's abstaining from attempting to exercise any power of eminent domain under North Carolina law related to the Facility. This conclusion also incorporates the provisions of Commission Rule R8-83, which requires, among other things, that the CPCN shall be subject to revocation under specified circumstances, the CPCN must be renewed if construction is not timely commenced, and that the CPCN holder, and all future holders of the CPCN, will obtain the approval of the Commission before selling, transferring, or assigning the CPCN and/or generating facility to an unaffiliated third-party. Any other planned sale, transfer, or assignment of the CPCN and/or generating facility is subject to Commission action as appropriate pursuant to Commission Rule R8-63(e)(4).

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

The evidence supporting these findings is found in the application, the exhibits attached thereto, and the testimony of NTE witness Green, NC WARN witness Powers, and Public Staff witness Metz.

NTE witness Green testified that the need for new generation in North Carolina is demonstrated in the Integrated Resource Plans (IRPs) filed by DEC and DEP in 2015. Taking into consideration projected load growth, the contributions of demand-side management and energy efficiency programs, and the planned retirements of older, less efficient plants, DEC's and DEP's 2015 IRPs concluded that 5,711 MW and 5,292 MW, respectively, of firm generating capacity would be needed to support system reliability through 2030. Collectively, the two IRPs projected a combined need for firm generating resources of over 11,000 MW through 2030.

Public Staff witness Metz testified that DEC and DEP filed more recent IRPs in September 2016, which reduced slightly some of the wholesale and retail load growth projections, but still concluded that a significant amount of firm generating capacity was needed in the Carolinas to maintain system reliability through 2031. DEC's 2016 IRP identifies a 5,002 MW need, and DEP's IRP identifies a 5,453 need, for a combined total need of 10,455 MW of additional, firm generating capacity.

The Commission takes notice that a number of public witnesses, and consumers filing statements outside of the public hearing, suggested that the NTE plant is not needed in their respective counties. The Commission notes that the output of the proposed plant is not intended to provide retail electric service to these customers. Further, the electricity produced by the facility may be purchased by a wholesale purchaser for use outside the region of Rockingham County. As NTE stated in its application, "The output of the Facility in Rockingham County likewise will be sold at wholesale and not to any end-user or retail customers in North Carolina." Witness Green also testified that "The exact location of that combined cycle capacity, as long as it can tie into the transmission grid, is pretty - - it's indifferent as to where as long as it gets into the transmission grid." (T Vol. 2, pp. 43-44) The Commission acknowledges the concern of the public witnesses that the electricity produced by the Facility may not be needed in Rockingham County. However, the Commission's responsibility is to determine the need on a much broader basis, that being whether the Facility is needed "in the state and/or region." Commission Rule R8-63(b)(3).

Based on its assessments and its investigation of market activity by regional load-serving entities, NTE identified specific wholesale customers who are interested in purchasing the output of its proposed Facility and is currently negotiating power supply agreements with them. NTE witness Green concluded that this interest further demonstrates that there is a need for the Facility. Without it, the Facility could not be financed and would not be built. He stated that an additional benefit of the Facility is that it will be developed and financed by private companies, rather than ratepayers. Witness Green noted that a public utility's cost to construct a generating plant becomes a part of the utility's rate base, on which the utility earns an allowed rate of return. On the other hand, NTE's Facility will be privately financed. Thus, the financial risks will be borne by private investors, not by utility ratepayers, because the construction costs of the Facility will not be considered in a future determination of the rate base of any public utility under Chapter 62 of the North Carolina statutes.

On cross-examination by NC WARN, witness Green was asked a number of questions about DEC's 2010 withdrawal of a CPCN application that DEC filed in 2008 and a statement in DEC's 2008 IRP that it did not need the power. Witness Green responded that combined cycle generation is needed now in North and South Carolina, as expressed by DEC and DEP in their IRPs and as expressed by the interests of the wholesale customers with which NTE is currently negotiating. NC WARN stated in its post-hearing Brief filed December 22, 2016, that DEC's application in 2008 for a certificate to add a baseload 677-MW natural gas plant at the Rockingham County CT Station is "highly relevant" to the present certificate case. NC WARN goes on to note that just two years after filing its application, DEC determined an additional baseload plant was not needed in the Reidsville area and summarily withdrew its application.[1]

[1] Rockingham Combustion Turbine Expansion Project Certificate of Public Convenience and Necessity, Docket No. E-7, Sub 861.

Further, on redirect witness Green testified about the increase in economic activity in the State and growth of the State's population since 2010. (See NTE Redirect Green Exhibit 1, which is a population overview prepared for the North Carolina Office of State Budget Management).[1] The State has been growing by about 500,000 people every five years, approximately one percent per year generally, and that rate of growth is projected to continue into the future. (T Vol.2, pp. 63-65, Redirect Green Exhibit 1) Witness Green further testified about the recession being at its height between 2008 and 2010 with no employment growth. In addition, he testified about the extensive plant closings that DEC and DEP had undertaken in the past several years, concluding that the need for supply side resources in the State of North Carolina was very different in 2016 than it was in 2008.

In response to NTE Redirect Exhibit Green No. 2, a copy of the Commission's 2015 Annual Report Regarding Long Range Needs for Expansion of Electric Generation Facilities for Service in North Carolina (2015 Annual Report), witness Green further testified that the 2015 Annual Report indicates significant increases in the peak loads for both Progress and Duke from 2012 through 2014.

The Commission is not persuaded on the present record that the decision of DEC in 2010 to withdraw its application for construction of a Rockingham County plant has any relevance to the current docket. The decision made by DEC in 2010 was unique to its IRP process and the prevailing economic conditions at that time.

NC WARN witness Powers testified in opposition to the requested CPCN, stating that there is no evidence of actual growth in peak demand or annual electricity usage in DEC's or DEP's service territories in the last decade. He further testified that the IRP peak demand forecasts relied upon by NTE witness Green are in conflict with actual DEC and DEP peak demand trends over the last decade. In addition, he testified that DEC and DEP reported anomalously high actual increases in winter peak loads in 2013 and 2014, reaching levels greater than forecast in the 2012 IRPs prepared by each utility. He stated that these have been described as polar vortex events and that there is no reason to build baseload capacity to meet a once-in-a-generation condition.

Witness Powers further testified that there was no increase in retail electricity consumption between 2007 and 2015 for DEC and no increase between 2006 and 2015 for DEP. The only area of electricity sales growth for DEC and DEP has been wholesale power sales. He stated that DEC's and DEP's forecasted load growth projections for 2016 through 2030, as set forth in their IRPs and relied upon by NTE witness Green, are wrong, and that there is no load growth for the proposed plant to meet.

On cross-examination, however, witness Powers acknowledged he undertook no independent modeling, no independent analysis of key economic factors, such as income, electricity prices, and industrial production indices, and no independent analysis or modeling of weather projections. He only looked at the last ten years of actual loads reported by DEC and DEP. He also testified on cross-examination that he did not consider population growth to be necessarily

[1] A sequence of webpages demonstrating the source of this exhibit was filed on December 1, 2016, by NTE as Late-Filed Redirect Green Exhibit 1A.

connected to load growth and that he made no assumptions about manufacturing output in North Carolina over the next 20 years.

Witness Powers further testified that the need for 500 MW of capacity of the proposed Facility can be met with existing available regional hydro or combined cycle capacity. He specifically cited the following: (1) four Smoky Mountain Hydro units near the North Carolina-Tennessee border that have a capacity of 378 MW and are connected to DEP West by a single 161-kV line from TVA to the substation at the Walters Hydro Plant in DEP West; (2) the underutilized 523-MW combined cycle merchant plant owned by Columbia Energy outside of Columbia, South Carolina; and (3) the 940-MW Tenaska combined cycle merchant plant located in Virginia, which on average has 350 to 400 MW of unused capacity.

Witness Powers presented these as examples of regionally available capacity, while admitting that he had not conducted an exhaustive investigation of available capacity in the Carolinas or neighboring states or the cost of power from these resources relative to a new combined cycle plant in Rockingham County. He nevertheless opined that he was reasonably certain that the cost of power from existing available hydro and combined cycle units would be lower than the cost of power from a new combined cycle plant serving the same load.

On cross-examination, witness Powers conceded that he had little information about the availability of these plants, their heat rates, or their cost of natural gas. In addition, he admitted that he had not evaluated whether sufficient transmission existed to import enough power from these plants into North Carolina, or what the wheeling costs would be if transmission capacity was available. He also conceded that he had not spoken to load-serving entities in Virginia, Tennessee or South Carolina about how the three examples of plants outside of North Carolina are depended upon for their own native system reliability and that he did not know if the energy and capacity from his proposed alternatives had been marketed to the customers that signed contracts with NTE for its Kings Mountain facility.

With regard to battery storage, witness Powers testified that such storage has been identified in at least one utilities commission proceeding in another state as the preferred resource over combustion turbine capacity to meet peak demand. He further stated that battery storage has the necessary characteristics to maximize the value of renewable energy resources as North Carolina transitions to higher levels of renewable power.

Public Staff witness Metz testified that with respect to the required showing of need, NTE's projection of need was based upon the IRPs of DEC and DEP, both of which show a need for additional capacity due to load growth and planned plant retirements. Given the future need for generation resources by DEC and DEP, witness Metz testified that the proposed Facility will assist in meeting the need. He also noted that one of the benefits of NTE's proposed merchant plant is that it will be financed by private companies, rather than ratepayers, and that its construction costs will not be a component of rate base for any North Carolina electric public utility.

On cross-examination by NTE's counsel, witness Metz agreed that in its comments in Docket No. E-100, Sub 141, filed on March 2, 2015, the Public Staff found that at the time of very high winter demand on January 7, 2014, DEP's available operating reserves fell to 0.19% at the time of its actual peak, and DEC's available operating reserves fell to 0.24% at the time of its actual peak.

On rebuttal, NTE witness Green stated that NTE has identified a clear need for additional power generation in the Carolinas in the years ahead that can be met in part by NTE's proposed Facility. The identified need is consistent with the peak demand forecasts filed by DEC and DEP in their approved IRPs and in their most recent 2016 IRP filings.

Witness Green further testified that witness Powers' testimony on behalf of NC WARN is incorrect or irrelevant in a number of respects. One of these is his improper focus on electricity consumption as opposed to peak demand and the need for capacity. The NC WARN approach is fundamentally incorrect in its failure to distinguish between "capacity" and "energy," how load forecasts are prepared for, and approved by, the Commission, and how the reliability of electricity systems during peak times is assured. He further stated that the IRPs address both peak demand growth and energy usage patterns, but the focus of the IRP process is to anticipate peak demand for both summer and winter seasons and then to make sure there is adequate firm generating capacity to meet those peaks with adequate reserve margins to ensure system reliability.

In addition, witness Green testified that accurate forecasting of peak demand and the availability of firm demand-side and supply-side resources to meet that demand are critical in maintaining system reliability. Available firm generation capacity – not energy usage over specified time periods as witness Powers analyzes – determines the ability of transmission balancing areas to satisfy fluctuating loads and meet peak demand requirements (at the times of the highest demand) without interruption and with prudent reserves in the system.

Witness Green further stated that, to the extent NC WARN and witness Powers are challenging the load forecasts, reserve margins, and other aspects of the currently-approved IRPs, those challenges have already been reviewed – and litigated – by the utilities, Public Staff, and Intervenors (including NC WARN) before the Commission. The Commission expressly rejected NC WARN's load forecast arguments in its Order Approving Integrated Resource Plans and REPS Compliance Plans, issued June 26, 2015, in Docket No. E-100, Sub 141 (2015 IRP Order). Thus, witness Green testified that it is appropriate for NTE to utilize those IRPs in this proceeding and unpersuasive for witness Powers to argue that DEC's and DEP's forecasts and analyses are wrong.

The Commission asked witness Green a number of questions related to NTE's analysis of need for the Facility. Witness Green testified that in addition to the IRP, NTE is in direct conversations with specific wholesale buying entities that are currently buying wholesale power from other parties and have the opportunity to look at other methods to service their needs. He testified that these specific four or five customers are the ones that are really guiding NTE's determination of need. Witness Green also testified to the fact that the process by which NTE is identifying specific wholesale customers who are interested in purchasing the output of the proposed Facility is similar to the process that NTE went through that resulted in the contracts for the Kings Mountain Energy Center. He testified that as long as they are not bound by some existing contract, any cooperative or municipal power agency in North Carolina is a potential wholesale customer for the proposed Facility. Witness Green also testified that he depends more on what the willing customers want, in terms of capacity and energy, than he does on what Duke projects will be statewide or system-wide the growth in retail demand. In addressing the issue of need for the proposed Facility, the Commission gives substantial weight to this testimony. However, the Commission gives no weight to the testimony of witness Green relative to his focus on peak demand only. Rather, the Commission is of the opinion that all components of the IRP planning process, including energy forecasts, are important to decisions made for the benefit of wholesale and retail customers in North Carolina.

In rebuttal testimony, witness Green re-emphasized that the risks associated with a merchant plant, such as the one NTE has proposed, differ from the risks associated with the construction of a utility-owned, rate-based power plant. Specifically, the costs incurred by a utility to construct power plants become part of the utility's rate base, on which the utility earns an allowed rate of return. In contrast, a merchant plant is privately financed, and the financial risks are borne by private investors, not by utility ratepayers. NTE assumes the risk involved in obtaining sufficient wholesale purchasers for its proposed Facility and, if it does not obtain those purchasers, then NTE and its investors bear the consequences. In response to a Commission question, witness Metz confirmed that, whatever happens in terms of the business of this Facility, it has no impact on the ratepayers.

It is reasonable for the Commission to require substantial evidence of the need for the Facility in the state and/or region, as required by Rule R8-63(b)(3). Prior to the adoption of the new Rule, there was no Commission rule specifically addressing the filing requirements for merchant plants. The Commission's Order Adopting Rule in Docket No. E-100, Sub 85 discusses development of the "Statement of Need" component of the new rule. The Order states:

> [T]he issue of what must be shown to establish the need for a merchant plant is one of the main concerns that prompted this proceeding to streamline certification procedures.
>
> The Public Staff's proposed Rule R8-63(b)(1) would require that applications for certificates for merchant plants include a showing of need as follows: "A description of the need for the facility in the state and/or region, with supporting documentation. This documentation shall include, as appropriate, either (i) contracts or preliminary agreements for the output of the facility, or (ii) information demonstrating that there is a need for the applicant's power in its intended market."
>
> [I]t is the Commission's intent to facilitate, and not frustrate, merchant plant development. Given the present statutory framework, the Commission is not in a position to abandon any showing of need or to create a presumption of need. However, the Commission believes that a flexible standard for the showing of need is appropriate. The Commission adopts the first sentence of the Public Staff's recommendation but will not adopt the second sentence.[1]

In weighing the evidence regarding the need for the NTE Facility, the Commission is guided by three main factors: (1) the standard of need for a merchant plant is different from the standard of need for a public utility electric generation facility; (2) DEC's and DEP's IRPs project the need for significant electric load growth in the Carolinas; and (3) NTE has demonstrated

[1] In the Matter of Investigation of Certification Requirements for New Generating Capacity in North Carolina, Docket No. E-100, Sub 85, Order Adopting Rule, at pp. 6-7 (May 21, 2001).

expertise in accurately evaluating wholesale market needs and negotiating with wholesale buyers to meet those needs.

With respect to the applicable standard of need, G.S. 62-110.1 is intended to provide for the orderly expansion of electric generating capacity in order to create a reliable and economical power supply and to avoid the costly overbuilding of generation resources. State ex rel. Utils. Comm'n v. High Rock Lake Ass'n, 37 N.C. App. 138, 141, 245 S.E.2d 787, 790, disc. rev. denied, 295 N.C. 646, 248 S.E.2d 257 (1978). One of the main purposes of avoiding overbuilding is to protect retail ratepayers from paying for unneeded electric generating capacity. In addition, the Commission is concerned about other potential adverse consequences of overbuilding. For example, the Commission is not going to certificate a facility that is likely to sit idle, litter the landscape and create unnecessary environmental impacts. One of the protections from such consequences of overbuilding is the need assessment conducted by the Commission. Further, the Commission must keep in mind that "The standard of public convenience and necessity is relative or elastic, rather than abstract or absolute, and the facts of each case must be considered. State ex rel. Utils. Comm'n v. Casey, 245 N.C. 297, 302, 96 S.E.2d 8, 13 (1957).

In its post-hearing Brief, NC WARN relies on the High Rock Lake case to argue that the Commission should deny NTE's application because NTE "is clearly overbuilding a redundant and unneeded plant that will be unreasonably costly to ratepayers." NC WARN's Brief, at p. 4. In addition, NC WARN asserts that DEC's ratepayers will in all likelihood be forced to pay for more unneeded generation for backup power to NTE.

Public Staff witness Metz testified that the construction costs of the Facility will not be a component of rate base for any North Carolina electric public utility. Commissioner Patterson asked witness Metz "Whatever happens in terms of the business of this plant being proposed, it has no impact on the ratepayers of North Carolina, does it?" Witness Metz responded "It has no impact on the ratepayers." (T Vol. 2, p. 177-178) NC WARN stated in its Brief that witness Metz did not provide the evidentiary basis for his conclusory statement or any detail as to why he thought ratepayers would not have to pay for additional generation to back up the NTE plant during normal maintenance outages or emergency outages. The Commission, however, accepts the testimony of witness Green that NTE through its energy manager will be responsible for fulfilling the contract requirements associated with the proposed Facility, not DEC or DEP. Further, the Commission notes that there is no evidence that DEC would have a contractual or legal obligation to provide backup power to the Facility. In addition, if DEC enters into a contract to provide backup power to the Facility, DEC's retail ratepayers will be protected from potential adverse consequences of the contract by two main factors. First, the contract would be at DEC's incremental costs to serve the Facility, thus avoiding any subsidization of the contract costs by DEC's retail ratepayers.[1] Second, DEC would be required to ensure that it has reliable power to serve its retail ratepayers before providing backup power to the Facility.[2] Therefore, the Commission agrees with witness

[1] Order on Advance Notice and Joint Petition for Declaratory Ruling, Docket No. E-7, Sub 858 (March 30, 2009).

[2] Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, Regulatory Condition No. 3.6(b), Docket Nos. E-2, Sub 1095, E-7, Sub 1100 and G-9, Sub 682 (September 29, 2016).

Metz's position that there is no rate impact, risk of service degradation, or risk of overbuilding being assumed by North Carolina's retail ratepayers.

In addition, as NC WARN acknowledges in its Brief, one of the Facility's goals is to sell power to current DEC, and possibly DEP, wholesale customers at a lower cost than those wholesale customers can get from DEC or DEP. One of the purposes of Commission Rule R8-63 is to streamline the CPCN process for merchant plants so that merchant plants will provide wholesale power alternatives that boost wholesale competition. The Commission expects that if an existing DEC wholesale customer enters into a contract with NTE, then that customer has indeed identified benefits associated with purchasing its power from the proposed Facility. In that circumstance, the goal of wholesale competition is advanced.

With respect to DEC's and DEP's IRPs, the Commission gives substantial weight to the testimony of Public Staff witness Metz that the IRPs demonstrate the need for a significant amount of firm generating capacity in the Carolinas to maintain system reliability through 2031. Witness Metz noted that DEC's 2016 IRP identifies a 5,002 MW need, and DEP's identifies a 5,453 need, for a combined total need of 10,455 MW of additional, firm generating capacity.

Finally, the Commission gives substantial weight to NTE's evidence, based on its assessments and its investigation of market activity by regional load-serving entities, that NTE has identified specific wholesale customers in the Carolinas who are interested in purchasing the output of its proposed Facility. NTE is currently negotiating power sale agreements with them. Further, the Commission gives some weight to the testimony of NTE witness Green that without agreements, the Facility cannot be financed and will not be built. In addition, the Commission gives significant weight to the testimony of NTE witness Green concerning NTE's success in obtaining wholesale buyers for the electricity to be produced at its Kings Mountain Energy Center. This record of success is some indication of NTE's ability to accurately forecast need and to negotiate wholesale contracts to meet that need. The Commission concludes that the market interest evidenced by witness Green's testimony, along with the capacity needs demonstrated by DEC's and DEP's IRPs, is sufficient to establish that there is a need for the Facility. Further, the Commission's assessment of the need for this Facility is made in the context of the Facility as a merchant plant, developed and financed by private companies, rather than ratepayers, and that the construction costs of the Facility will not be considered in a future determination of the rate base of any public utility. Unlike a public utility, NTE is a wholesale generator, has no captive customers, and has no authorized rate of return.

NC WARN's evidence as to alternative merchant plants is unpersuasive, as it is based upon general observations about availability, without specific inquiry or analysis. In contrast, witness Green testified that, based on his personal conversations with the wholesale customers of the Kings Mountain Energy Center and the prospective customers of the Facility, the wholesale customers are fully aware of other merchant facilities in the region. Obviously, if such alternative facilities had adequate uncommitted capacity, favorable economic pricing, and their electricity could be wheeled with reliable transmission interconnection, these customers would not be interested in NTE's proposed project.

Similarly, NC WARN's evidence as to the availability of battery storage as an alternative is not substantial or persuasive.

Based on the evidence, the Commission concludes that NTE has made a sufficient showing of need for its proposed 500-MW merchant electric generating plant in Rockingham County. The Commission also concludes that the proposed Facility will likely provide electric reliability benefits that further support the grant of the CPCN in this proceeding. Therefore, the Commission finds and concludes that the public convenience and necessity will be served by granting NTE a CPCN for construction of the proposed combined cycle generating Facility, subject to the conditions set forth herein.

IT IS, THEREFORE, ORDERED as follows:

1. That a certificate of public convenience and necessity shall be, and is hereby, issued to NTE Carolinas II, LLC, for the construction of a 500-MW natural gas-fueled combined cycle merchant plant generating facility, associated equipment, and ancillary transmission facilities.

2. That Appendix A hereto shall constitute the certificate of public convenience and necessity issued for the Facility.

3. That the certificate of public convenience and necessity is conditioned upon the requirement that the Facility be constructed and operated in strict accordance with applicable laws and regulations, including any local zoning and environmental permitting requirements.

4. That the certificate of public convenience and necessity does not and is not intended to confer the power of eminent domain under North Carolina law for the construction of the approximately 500-MW natural gas-fueled combined cycle generating facility certified herein, and NTE and its successors shall abstain from attempting to exercise eminent domain under North Carolina law in relation to the generating facility authorized by this certificate.

5. That the certificate of public convenience and necessity is conditioned upon a requirement that the certificate holder, including all future holders of the certificate, obtain the approval of the Commission before selling, transferring, or assigning the certificate and/or generating facility to an unaffiliated third-party, and that any other planned sale, transfer, or assignment of the certificate and/or generating facility shall be subject to Commission action as appropriate pursuant to Commission Rule R8-63(e)(4).

6. That the certificate of public convenience and necessity is subject to the conditions set forth in Commission Rule R8-63(e) and (f) as stated in the express language of the attached certificate.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of January, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. EMP-92, SUB 0

NTE Carolinas II, LLC
24 Cathedral Place, Suite 300
St. Augustine, Florida 32084

is hereby issued this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
PURSUANT TO G.S. 62-110.1

for construction of a 500-MW natural gas-fueled combined cycle merchant plant generating facility to be commenced within three years of this Certificate, consisting of one combustion turbine, one heat recovery steam generator, and one steam turbine generator and ancillary transmission facilities

located
in Rockingham County, North Carolina, between Highway 65 to the east and New Lebanon Church Road to the west,

subject to the following conditions: (a) NTE Carolinas, II, LLC, will construct and operate the generating facility in strict accordance with applicable laws and regulations, including any local zoning and environmental permitting requirements; (b) NTE Carolinas, II, LLC will not assert that the issuance of the certificate in any way constitutes authority to exercise any power of eminent domain, and it will abstain from attempting to exercise such power; (c) NTE Carolinas II, LLC, will obtain approval of the Commission before selling, transferring, or assigning the certificate and/or generating facility; (d) this certificate is subject to Commission Rule R8-63 and all orders, rules, regulations and conditions as are now or may hereafter be lawfully made by the Commission.

ISSUED BY ORDER OF THE COMMISSION
This the 19th day of January, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

DOCKET NO. EMP-93, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Wilkinson Solar LLC for a Certificate of Public Convenience and Necessity to Construct a 74-MW Solar Facility in Beaufort County, North Carolina	))))	ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

HEARD ON: Wednesday, May 17, 2017, at 7:00 p.m., at the Beaufort County Courthouse, District Courtroom, 112 W. Second Street, Washington, North Carolina; and

Monday, May 22, 2017, at 2:00 p.m., and Tuesday, May 23, 2017, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Commissioners James G. Patterson and Lyons Gray

APPEARANCES:

For Wilkinson Solar, LLC:

Henry C. Campen, Jr., and E. Merrick Parrott, Parker Poe Adams & Bernstein, LLP, 301 Fayetteville Street, Suite 1400, Raleigh, North Carolina 27601

For Mr. David Butcher:

Brady W. Allen, and Dwight Allen, The Allen Law Offices, PLLC, 1514 Glenwood Ave. Suite 200, Raleigh, NC 27608

For the Using and Consuming Public:

Dianna Downey, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, NC 27699

BY THE COMMISSION: On March 13, 2017, Wilkinson Solar LLC (Applicant or Wilkinson) filed an application pursuant to G.S. 62-110.1 and Commission Rule R8-63 for a certificate of public convenience and necessity (CPCN) to construct a 74-MW_{AC} solar photovoltaic (PV) electric generating facility in Beaufort County, North Carolina, to be operated as a merchant plant. On the same date, the Applicant pre-filed the direct testimony of April Montgomery and Meghan Schultz in support of the application.

On March 24, 2017, the Public Staff filed a Notice of Completeness, stating that it has reviewed the application as required by Commission Rule R8-63(d) and that it considers the application to be complete. In addition, the Public Staff requested that the Commission issue a procedural order setting the application for hearing, requiring public notice pursuant to G.S. 62-82, and addressing other procedural matters.

On March 27, 2017, the Commission issued an order setting the application for hearing, requiring the Applicant to provide appropriate public notice, establishing deadlines for the filing of petitions to intervene, intervenor testimony, and rebuttal testimony, and requiring the parties to comply with certain discovery deadlines.

Subsequently, on or after April 26, 2017, more than 60 consumer statements of position were filed in this docket.

Also on April 26, 2017, as supplemented on May 4, 2017, Alan Meijer filed a petition to intervene, not for himself but on behalf of the Terra Ceia Christian School Society, and David Butcher filed a petition to intervene, pro se. On May 15, 2017, the Commission issued an Order granting Mr. Butcher's petition. On May 17, 2017, the day of the scheduled public witness hearing, the Commission issued an Order denying Mr. Meijer's petition because, although the Commission's General Counsel had advised Mr. Meijer that only a licensed attorney could represent the Terra Ceia Christian School (the School), neither Mr. Meijer nor the School had caused an attorney authorized to practice law in this State to enter an appearance on behalf of the School, a corporate entity.[1] On May 19, 2017, after the public witness hearing, counsel for Mr. Butcher filed a notice of appearance on his behalf with the Commission.

On May 2, 2017, the State Environmental Review Clearinghouse of the North Carolina Department of Administration filed comments with the Commission concerning the application, stating that, because of the nature of the comments, no further review action is needed by the Commission to determine compliance with the North Carolina Environmental Policy Act.

On May 4, 2017, the Public Staff filed the direct testimony of Evan D. Lawrence, an engineer in the Electric Division of the Public Staff.

On May 5, 2017, the Applicant filed an Affidavit of Publication prepared by an employee of the Washington Daily News, stating that the Applicant had caused publication of public notice as required by the Commission's March 27, 2017 Order.

On May 9, 2017, the State Environmental Review Clearinghouse filed additional comments, again stating that, because of the nature of the comments, no further review action is needed by the Commission to determine compliance with the North Carolina Environmental Policy Act.

On May 12, 2017, the Applicant filed the supplemental testimony of April Montgomery and Paul Thienpont.

On May 17, 2017, the Commission conducted a public hearing at the Beaufort County Courthouse in Washington, North Carolina, as provided in the Commission's March 27, 2017

[1] While withholding its ultimate ruling on Mr. Meijer's petition to intervene, the Commission noted in its May 15, 2017 Order on Motion Regarding Hearing Procedure that Mr. Meijer was not an attorney and would not be allowed to represent the School.

Order, for the purpose of receiving public witness testimony. Sixteen public witnesses testified at the hearing: Stacy Jones, Rita Lee, Alan Meijer, Myra Beasley, Jennifer Skvarla, Josh Allen, Jeanne van Staalduinen, William van Staalduinen, Brian Bowen, Eddie Ewell, Catherine Meijer, Patricia Dorn, Vern Parsons, Macon Respess, Daren Hubers, and Kenneth Leys. The concerns expressed by the public witnesses primarily related to (1) the proximity of the proposed facility to the School and the potential for harm to students and the School's property that might result from the proximity to the facility, and (2) the potential harm to the future existence of the School, including the concerns that the aesthetics of the adjoining solar PV facility, a perceived incompatibility of use of the site for solar PV facility adjacent to the School, and a perceived impact on public health could negatively impact future enrollment at the School.

On May 22, 2017, the Commission resumed the hearing, as scheduled, for the purpose of receiving the expert testimony of the parties. At the hearing, just prior to the receiving of evidence, Mr. Charles Lollar noted his appearance and represented that he was appearing as counsel on behalf of the School. He moved that the Commission reconsider the School's motion to intervene. The Applicant objected to the motion and both the Applicant and Mr. Lollar, on behalf of the School, were heard on the motion. The School's motion for reconsideration was denied, but Mr. Lollar was permitted to remain at counsel table where he could and did consult with intervenor Butcher's counsel; the School's objection to denial of the motion for reconsideration was noted for the record.

On May 26, 2017, and June 20, 2017, the Applicant filed late-filed exhibits, as requested by the Commission, comprised of a revised organizational chart for the Applicant reflecting an updated upstream ownership structure, a site layout annotated to include the names of the record owners of parcels within and adjacent to the proposed facility, and confidential copies of the most recent audited balance sheet and income statement of Invenergy Wind LLC (renamed on May 24, 2017, to Invenergy Renewables LLC).

Proposed orders and briefs were filed by the Applicant and Mr. Butcher on June 22, 2017.

On August 3, 2017, noting the Presiding Commissioner's comments at the close of the hearing encouraging all parties, persons, and entities with an interest in this matter to meet and discuss the possibility of resolving this matter amicably, the Commission issued an Order Requiring Additional Post-Hearing Filings, directing the parties to submit appropriate additional filings addressing the status of negotiations and providing a forecast of the likelihood of a compromise.

On August 30, 2017, the Applicant, Mr. Butcher, and the School made a Joint Post-Hearing Filing as required by the Commission's Order stating that, after extensive, good faith negotiations, the Applicant, Mr. Butcher, and the School had reached an agreement whereby Mr. Butcher, the School, Harlene Van Staalduinen, and Stuart Ricks agreed to withdraw any and all objections and complaints against the facility proposed by the Applicant in this docket. A confidential term sheet summarizing the agreed-upon terms was attached to the joint filing. Also on August 30, 2017, the Applicant filed on behalf of Mr. Butcher, Harlene Van Staalduinen, Gertrude Respess, Stuart Ricks, and William Van Staalduinen (on behalf of the School as President of its Board of Directors) the referenced notices of withdrawal of all objections or complaints regarding the proposed facility.

On September 11, 2017, the Applicant filed a letter confirming execution of the ancillary agreements necessary to consummate the provisions of the previously filed confidential term sheet regarding the settlement in this proceeding.

On September 22, 2017, Advanced Energy Corporation filed a letter responding to others' comments and opining that the expected capacity factor for the proposed facility is within the range expected of a modern, large-scale system built in North Carolina.

On October 9, 2017, the Applicant filed an amended site layout reflecting that, although not modifying the original project boundary, it is no longer requesting to place solar panels on the property adjoining the School and that it is moving the substation and potential future battery storage facility to the southwestern portion of the project footprint.

Based upon the foregoing, including the testimony presented at the hearing and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. The Applicant is organized under the laws of the State of Delaware with its principal place of business in Chicago, Illinois, and it is authorized to do business in North Carolina. The Applicant is a subsidiary of Invenergy Renewables LLC, which is an affiliate of Invenergy LLC (Invenergy).

2. In compliance with G.S. 62-110.1 and Commission Rule R8-63, the Applicant properly filed with the Commission an application for a CPCN authorizing the construction and operation of a solar photovoltaic (PV) electric generating facility with a generating capacity up to 74-MW_{AC} to be located in Beaufort County, North Carolina.

3. The application states that the proposed facility will be located on approximately 600 acres on the south side of Terra Ceia Road, between Vreugdenhil Road and Christian School Road, and the north side of Terra Ceia Road, east of Christian School Road, in the Terra Ceia community in Beaufort County, North Carolina.

4. The facility will consist of solar PV panels affixed to ground mounted racks supported on driven piles, inverters, and a substation. The facility may also include a battery system, which would be interconnected to the substation. The facility will be interconnected to the electric transmission system owned and operated by Virginia Electric and Power Company d/b/a Dominion Energy.

5. Construction of the facility is anticipated to begin on January 1, 2018, with commercial operation scheduled to begin as early as December 31, 2018. The facility has an expected useful life of at least 25 years.

6. The Applicant is financially fit and operationally able to undertake the construction and operation of the facility as a merchant plant, financed by private companies rather than ratepayers. If assets become stranded, the facility owner will face the financial consequences, not captive North Carolina retail electric customers. Under the proposed ownership structure, the construction costs of the facility will not qualify for inclusion in, and will not be considered in a

future determination of the rate base of a public utility pursuant to G.S. 62-133.Thus, construction of the proposed facility creates no financial risk to North Carolina retail electric customers.

7. The granting of the CPCN in this proceeding should be subject to the following conditions:

a. That the Applicant construct and operate the facility in strict accordance with applicable laws and regulations, including any local zoning and environmental permitting requirements;

b. That the Applicant or any successor certificate holder will not assert that issuance of the CPCN in any way constitutes authority to exercise a power of eminent domain, and it will abstain from attempting to exercise such power; and

c. That the CPCN shall be subject to Commission Rule R8-63(e) and all orders, rules and regulations as are now or may hereafter be lawfully made by the Commission.

8. The Applicant demonstrated that the proposed facility, as amended, is consistent with the public convenience based on the public benefits of solar-powered electric generation and the investment in the local economy. Mr. Butcher and the School have withdrawn their objections to the proposed facility, and the required regulatory permits and approvals, and the conditions imposed by the Commission for the construction of the facility, are sufficient to ensure that the remaining concerns expressed by the public witnesses are appropriately addressed. In addition, the Applicant committed to decommission the facility and to construct and operate the facility in compliance with state and federal laws.

9. The Applicant demonstrated the need for the proposed facility based on the public benefits of solar-powered electric generation and state and federal law and programs promoting the development of renewable energy resources and merchant power plants. In addition, the Applicant demonstrated that Dominion Energy and the PJM Interconnection show a need for the electric output from the facility over the next 15 years, based upon projected load growth and requirements for procurement of renewable energy in Dominion Energy's North Carolina service territory and in the PJM region.

10. The Applicant is in discussions with potential buyers for the electric output of the facility and the renewable energy credits (RECs) earned by the facility. The facility's electric output can be used by Dominion Energy and/or by retail electric providers within the PJM Interconnection to meet growing demand for electricity. The RECs earned by the facility can be used by North Carolina electric power suppliers to meet the requirements of the North Carolina Renewable Energy Portfolio Standard (REPS), or sold to electric providers in the PJM Interconnection region to meet the requirements of other states' renewable energy portfolio standard requirements or goals.

11. It is reasonable, appropriate, and serves the public interest to grant the requested CPCN to the Applicant, as conditioned herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-5

These findings of fact are essentially informational, procedural, and jurisdictional in nature, and are not in dispute. The evidence supporting these findings is found in the application, as amended, and in the testimony of the Applicant's witnesses Montgomery and Schultz, and the Public Staff's witness Lawrence. A copy of the Certificate of Authority issued by the Secretary of State of North Carolina, establishing the authority of Wilkinson to do business in this State, was filed in this docket on April 7, 2017, as a supplemental exhibit to the application.

According to the application, and as witness Montgomery testified, the facility will be located on approximately 600 acres in Beaufort County, North Carolina, in the Terra Ceia community. The facility will be located on the south side of Terra Ceia Road, between Vreugdenhil Road and Christian School Road, and on the north side of Terra Ceia Road, east of Christian School Road. A map of the proposed Project Area is included as an exhibit with the application, and an annotated map was filed on May 26, 2017, as a late-filed exhibit as requested by the Commission. An amended site map was filed by the Applicant on October 9, 2017, indicating that, without modifying the original project boundary, it no longer intends to place solar panels on the property adjoining the School and that it is moving the substation and potential future battery storage facility to the southwestern portion of the project footprint, on the south side of Terra Ceia Road.

As described in the application, a three-breaker ring bus interconnection substation will be located within the boundaries of the property under the Applicant's control, and a short generator tie line will be used to connect the facility to Dominion Energy's transmission line adjacent to the site. The facility will generate RECs that can be used to meet the requirements of the REPS or renewable energy goals or mandates of other states within the PJM Interconnection. Witness Montgomery's testimony included reference to a PJM Renewable Integration Study, which she cites to show that as of March 31, 2014, every jurisdiction in the PJM footprint, except Kentucky and Tennessee, has requirements or goals for production of electricity from facilities fueled by renewable or alternative resources.

Witness Montgomery also testified that the facility may incorporate a "large-scale advanced battery system." She stated that the battery system would complement the electric output of the facility by regulating frequency, balancing variations in solar production, energy shifting, digital peaking, and/or transmission and distribution deferral. According to witness Montgomery, the battery system would consist of lithium-ion battery racks housed in a custom building or prefabricated shipping containers, and would prolong the maximum discharge period of the facility, but not increase its maximum discharge capability. Finally, with regard to the facility components, witness Montgomery testified that the facility will include a substation that will be constructed adjacent to Dominion Energy's 115-kV transmission line that runs through the site. Witness Montgomery made reference to addendum 6 to the application, stating that the facility will be interconnected to that transmission line between Dominion Energy's Pantego and Five Points substations.

Witness Montgomery further testified that construction of the facility is expected to occur throughout 2018, with a projected commercial operation date as early as December 31, 2018. The expected service life of the facility is at least 25 years. Witness Montgomery also testified that the nameplate generating capacity of the facility will be up to 74-MW_{AC}, the anticipated annual gross output of the facility is 209,850.997 MWh, and the anticipated net output is 175,376.816 MWh per year.

Witness Lawrence testified as to the Applicant's description of the facility as contained in the application. Based upon his review, witness Lawrence testified that the Applicant complied with the Commission's filing requirements. Therefore, he notes, that on March 24, 2017, the Public Staff notified the Commission that the Public Staff considered the application to be complete and requested that the Commission issue a procedural order setting this matter for hearing. Further, witness Lawrence recommended that the application for the CPCN be approved subject to conditions discussed further below.

An examination of the application, as amended, and the testimony and exhibits of the Applicant's witnesses confirms that the Applicant has complied with the filing requirements associated with applying for a certificate to construct a merchant plant in North Carolina. No party asserted that the application for CPCN failed to include information required by the Commission's rules, nor that the filing was deficient in any manner. Therefore, the Commission finds that the Applicant has demonstrated that it is properly organized and authorized to do business in this state, and that the application was properly filed as required by G.S. 62-110.1 and the relevant Commission rules.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 6

The evidence supporting this finding of fact is found in the application, as amended, and in the testimony of the Applicant's witnesses Montgomery and Schultz, and the Public Staff's witness Lawrence.

The Applicant is a subsidiary of Invenergy Renewables LLC, which is an affiliate of Invenergy LLC (Invenergy). The Applicant was organized to facilitate development of the facility. Financial statements of Invenergy Clean Power LLC, the original upstream owner of the Applicant, were provided as exhibits to the application. Witness Schultz testified that, after a corporate reorganization, the Applicant became a second tier subsidiary of Invenergy Renewables LLC, and on May 26, 2017, the Applicant filed an updated organizational chart reflecting the reorganization. The Applicant also filed financial statements for Invenergy Renewables LLC under seal, as a late-filed exhibit on June 20, 2017. Witness Schultz testified in detail as to Invenergy Renewables LLC's capability to arrange adequate assurances, guarantees, financing, and insurance for the Applicant's development, construction, and operation of the facility. As stated in the Application, the Invenergy-affiliated companies develop, own, and operate large-scale wind energy, solar energy, advanced energy storage, and natural gas-fueled electric generation assets in North America, Latin America, Japan, and Europe.

Witnesses Schultz and Montgomery testified to the Applicant's financial and operational ability to construct and operate the proposed facility and to the Applicant's ability to market the electrical output of the facility. Witness Schultz testified that Invenergy Renewables LLC will arrange the financing of the facility, which will include a construction loan plus equity provided by Invenergy. Witness Montgomery further testified to the financial structure of this project, which will involve a combination of third-party debt and equity to finance construction of the facility and the addition of a tax-equity partner once the facility is operational.

Witness Schultz further testified that Invenergy, the parent entity, structures and arranges project financings through a dedicated in-house staff of finance professionals. Witnesses Montgomery and Schultz testified that Invenergy has raised more than $23 billion of financing since 2001 and has worked with more than 60 financial institutions worldwide. Witness Montgomery also testified to the Invenergy companies' experience in raising financing for energy projects in the U.S. and abroad, stating that Invenergy is an experienced operator of renewable and thermal energy facilities through its wholly owned subsidiary, Invenergy Services. Invenergy Services currently operates more than 6,700 MW of thermal and renewable energy generation projects in North America. Invenergy was recognized in 2011 and 2017 for its strong operations and maintenance capabilities with the American Wind Energy Association award for Operational Excellence. Witness Schultz further testified that Invenergy has been awarded multiple awards related to its financing capabilities, including Power, Finance & Risk magazine's 2012 and 2013 Project Finance Borrower of the Year for the breadth, diversity, and volume of deals brought to market and successfully financed by Invenergy. Finally, the Commission notes that the Applicant filed in this docket additional supportive and detailed financial information under seal as confidential trade secret information.

No party disputed the Applicant's testimony with regard to its financial fitness and operational ability to undertake construction and operation of the facility as a merchant plant.

Witness Montgomery also testified that a significant benefit of this project is that it will be privately financed and constructed and will not affect ratepayers. Further, she testified that any risk of default is on private financiers and not North Carolina retail electric customers. Public Staff witness Lawrence agreed with the Applicant's witness on these two points.

The absence of an impact on North Carolina ratepayers and the financial and operational abilities of an applicant for CPCN are factors that the Commission has traditionally relied upon in determining whether to issue a CPCN for a merchant power plant. For example, in its Order Granting Certificate with Conditions, issued on January 19, 2017, in Docket No. EMP-92, Sub 0, the Commission relied on similar evidence that there would be "no financial risk to North Carolina retail electric customers" and evidence of the applicant's financial and operational abilities to successfully construct and operate the facility and market the electrical output of the facility to buyers. See Order Granting Certificate with Conditions, Docket No. EMP-92, Sub 0, January 19, 2017, at 17-18.

Based on the foregoing and the entire record herein, the Commission finds that the Applicant and its affiliated corporate entities have significant experience in the financing, construction, and operational control of renewable energy facilities, and that this sufficiently demonstrates that the Applicant is financially fit and operationally able to undertake the construction and operation of the facility as a merchant plant and to market the electrical output to potential buyers. The Commission further finds that as a merchant plant the facility will be financed by private companies rather than ratepayers, and, thus, if assets become stranded, the owner will face the financial consequences, not captive North Carolina retail electric customers. As such, under the proposed ownership structure, the construction costs of the facility will not qualify for inclusion in, and will not be considered in a future determination of, the rate base of a public utility pursuant to G.S. 62-133, and construction of the facility creates no financial risk to

North Carolina retail electric customers. The Commission concludes that this evidence supports issuance of the CPCN.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7 AND 8

The evidence supporting these findings of fact is found in the application, as amended, and the testimony and exhibits of the Applicant's witnesses Montgomery and Thienpont, the Public Staff's witness Lawrence, Mr. Butcher, and the witnesses testifying at the public hearing.

The Applicant's evidence in support of its argument that the construction and operation of the facility is consistent with the public convenience is found in the application, as amended, and the supporting testimony and exhibits of witnesses Montgomery and Thienpont. In addition to the facility's contribution to meeting energy needs in the state and region and achieving state and federal requirements and goals, as discussed below, witness Montgomery testified that the facility represents an investment of tens of millions of dollars in the Beaufort County community, realizing annual property tax revenue to the County of approximately $55,000. Applicant Montgomery Hearing Exhibit 1 provides that the "project will supply over 70 [MW] of emissions-free electricity, enough to power over 16,000 homes." In addition, the "project will create over 250 jobs during the construction process, as well as numerous opportunities for local vendors, from restaurants and hotels to contractors and inspectors."

As required by Commission Rule R8-63(b)(2)(v), Exhibit 2 of the application contains a list of all needed federal, state, and local approvals related to the facility and site. Witness Montgomery testified that the facility may need a wetlands permit from the Army Corps of Engineers, although that determination has not yet been made. She further testified that the Applicant provided the results of a Solar Glare Hazard Analysis Tool to the Department of Defense, and on April 20, 2017, the Applicant received a letter from Camp Lejuene that states "no installation member of the North Carolina Commanders Council has raised any concerns over the project as proposed."

With regard to State approvals, witness Montgomery testified that the facility will require a) a stormwater management permit from North Carolina Department of Environmental Quality (NCDEQ); b) an erosion and sedimentation and control plan and stormwater general permit coverage for construction-related activities, which would also be filed with or issued by NCDEQ; and c) driveway permits from North Carolina Department of Transportation. With regard to the local approvals, witness Montgomery testified that the facility has obtained or will be required to obtain the following permits from Beaufort County: a solar development permit, a building permit, and an electrical permit. By its application and the testimony of its witnesses, the Applicant committed to construct and operate the facility in compliance with all applicable permits and regulations.

Mr. Butcher and several of the public witnesses expressed concerns about the proposed facility that relate to the appropriateness of use of the site for a solar PV facility because the surrounding land uses are residential, agricultural, and educational. The public witnesses also expressed concerns about the environmental impacts of the proposed facility, such as water runoff to and flooding of nearby properties and leachate of chemicals from the solar panels to the ground or surface waters. Still other concerns of the public witnesses centered on public health and safety issues; for example, concern that the battery component of the facility might explode or ignite, and concerns and questions about the proximity of the School to an electric generating facility, which, some public witnesses feared could endanger the health of the students and staff of the School.

Public Staff witness Lawrence testified that the public witnesses' concerns related to the siting of the proposed facility and environmental impacts are more appropriately addressed through the local permitting process and the environmental permitting process. Witness Lawrence noted that the Commission discussed local authority over the siting of facilities in its Order issued on April 24, 2008, in Docket No. SP-231, Sub 0, stating, "such decisions are, in most instances, best to the local community through the exercise of its zoning authority rather than made by the Commission." Further, witness Lawrence stated that the Public Staff does not have particular expertise in the area of the impacts of electric generation on the environment. Therefore, he testified that those issues should be left to the purview of environmental regulators who have expertise in this area and who are responsible for issuing specific environmental permits for electric generating facilities. Accordingly, witness Lawrence recommended that the Commission require compliance with applicable laws and regulations, including any environmental permitting requirements, as a condition to issuance of the permit. Witness Lawrence also testified that during discovery, the Applicant indicated that it has obtained legal control over all of the Project Area except for one parcel, and, therefore, the Public Staff recommended that the Commission additionally condition the granting of the CPCN in this matter on obtaining all necessary documents representing legal control over all of the Project Area. Finally, the Public Staff recommended that the application be approved subject to two further conditions: 1) that the Applicant will not assert that issuance of the CPCN in any way constitutes authority to exercise a power of eminent domain and that the Applicant will abstain from attempting to exercise such power; and 2) that the CPCN should be subject to Commission Rule R8-63(e) and all orders, rules, and regulations as are now or may hereafter be lawfully made by the Commission.

The post-hearing filings in this proceeding demonstrate that the Applicant, Mr. Butcher and the School came together to discuss and resolve many, if not all, of the concerns about the proposed facility expressed in this proceeding, particularly with regard to the impact on the School and its students and faculty. As a result, Mr. Butcher and the School's objections have been withdrawn. The amended site map filed by the Applicant on October 9, 2017, indicates that, without modifying the original project boundary, the Applicant no longer intends to place solar panels on the property adjoining the School and that it is moving the substation and potential future battery storage facility to the southwestern portion of the project footprint, on the south side of Terra Ceia Road. The Commission has carefully considered the remaining concerns raised by the public witnesses who appeared at the public hearing and by the consumer statements of position filed in this docket.

With regard to concerns about hazardous substances, witness Thienpont testified that solar panel technologies have been in use for more than 50 years, and that they pose no health or safety risk. Further, he testified that the modern silicon-based panels pass the Environmental Protection Agency's toxic leaching characteristic procedure test, which classifies the panels as non-hazardous waste and shows that the panels do not pose a threat to health, ground water, or well water. With regard to the potential incorporation of a battery at the facility site, witness Thienpont testified that the battery storage components will be contained within a structure that isolates the batteries from the external environment and will include safety and monitoring equipment.

As to concerns about flooding and electrocution, witness Thienpont testified that the facility would be designed around historic flood levels to ensure protection of any equipment, and that the facility would be safely designed and properly grounded consistent with the National Electric Safety Code. The Applicant's witnesses further testified that the Applicant would be required to obtain permits that mandate measures to mitigate or eliminate water runoff and soil erosion, and that the facility would be constructed and operated in compliance with these permits and other regulations for protection of the environment.

With regard to concerns about flying debris, witness Thienpont testified that the Applicant will obtain a building permit from Beaufort County and that the permit review process incorporates wind load testing. The county permit review will require that the facility be designed to withstand the wind loads associated with the North Carolina Wind Zone Map, and the engineering of the site will assess the pile sizing, spacing, and embedment depth to ensure that the system can structurally withstand the wind loads associated with the design criteria wind speeds. Thus, in response to specific questions from the Commission at the hearing, witness Thienpont answered that assurances that the facility would be sufficient to withstand wind speeds applicable to the area "would be handled throughout the building permit process."

Finally, witness Thienpont addressed the concerns that glare from the facility would create a hazard. He testified that the Applicant has conducted three glare studies using a tool developed by Sandia National Laboratories that evaluates the potential for glare at various viewpoints, including flight paths, observation points, and surfaces, based upon the project design and equipment used at the actual site through a simulation of every hour of the day for all seasons based on the sun angle in a clear sky. These studies, about which witness Thienpont testified and a summary of results was introduced at the hearing as Applicant Thienpont Hearing Exhibit 1, have yielded no potential for any hazard due to glare for flight paths and observation points from the school, the church, nearby residences, and along the roads bordering the site. Further, he testified that the panels will utilize lightly textured glass with an anti-reflective coating designed to minimize glare and maximize the amount of sunlight incident on the solar cells.

With regard to concerns about the reduction in farmland, witness Montgomery noted that the 600 acres proposed to be used for the Applicant's facility accounts for only about 0.4% of Beaufort County farmland. Further, and in response to concerns regarding the decommissioning of the facility and the long-term effects of the presence of a solar PV facility, she and witness Thienpont testified that at the end of the facility's useful life, the facility will be decommissioned as is required by the Beaufort County ordinance regulating solar PV facilities and the contracts for lease of the facility site, and the land can be returned to agricultural production. In response to other concerns, including aesthetics, witness Montgomery and public witness Jones testified that the Applicant has proposed a larger buffer between the facility and the adjoining residences to mitigate the concern related to negative impact on property values.

The Commission finds that the Applicant has adequately responded to the concerns raised by the public witnesses in this proceeding and further agrees with the Applicant and the Public Staff that these issues are better addressed by agencies with expertise and regulatory authority in the areas of environmental and natural resource protection, and public health and safety, and through the local zoning process.

The Commission agrees with the Applicant and the Public Staff that it is appropriate to issue the CPCN subject to the Public Staff's recommended conditions, modified as proposed and agreed to by the Applicant. The Commission concludes that these conditions are appropriate as the Applicant's ongoing duty to comply with the conditions related to protection of the environment and public health and safety sufficiently address the concerns expressed by the public witnesses. These conditions ensure that the facility is operated in a manner that protects the environment and natural resources, and mitigates or eliminates potential harm to the public health and safety – at least to the extent that federal, state, and local policymakers have determined is appropriate. Additionally, the imposed agreed-upon conditions are consistent with past considerations and determinations of the Commission when granting applications for CPCNs, particularly in the context of merchant generating plants.

Therefore, based upon the foregoing and the entire record herein, the Commission finds that the granting of the requested CPCN should be subject to the conditions detailed in this order and that these conditions are sufficient to ensure that the environmental and public health and safety concerns expressed by Mr. Butcher and the public witnesses are appropriately addressed.

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

The evidence supporting these findings of fact is found in the application, as amended, and the testimony of the Applicant's witness Montgomery and the Public Staff's witness Lawrence. Mr. Butcher, as noted earlier, withdrew any objections previously raised regarding the need for the proposed facility.

The application and witness Montgomery's testimony support the required showing of need for the facility. First, she testified that the facility can provide RECs to North Carolina utilities that can be used to comply with the requirements of the REPS, estimating that the facility is expected to earn approximately 175,377 RECs annually. Second, she testified that the facility will generate RECs that can be used to comply with renewable energy requirements in other states within the PJM, stating that every state in the PJM region, with the exception of Kentucky and Tennessee, have such requirements or goals. Third, she testified that the facility will help meet increases in peak energy requirements forecasted in DNCP's most recent Integrated Resource Plan. Fourth, she testified that the facility will contribute to meeting increases in peak load growth forecasted for PJM.

Public Staff witness Lawrence testified that based upon his review of the application, the Applicant has shown a need for the proposed facility. In addressing the need, witness Lawrence first noted that the Applicant anticipates the facility to earn 175,377 RECs annually, contributing to electric power suppliers' compliance with the REPS. He further notes that the Applicant demonstrated, based on Dominion Energy's IRP, that Dominion Energy estimates its energy requirements will grow approximately 1.5% annually through the 15-year planning period, and that wholesale and retail energy sales will grow at an annual rate of 0.6% and 1.7%, respectively. Based upon this showing, and his review of the Applicant's other evidence, witness Lawrence recommended that the Commission approve the application.

Based upon the foregoing and the entire record herein, the Commission finds that the Applicant demonstrated the need for the proposed facility sufficient to meet the requirements of G.S. 62-110.1 and Commission Rule R8-63 based on projected load growth and generation asset retirements in North Carolina and in the region, the state and federal policy promoting enhanced competition in the wholesale electric power generation market, and the requirements for procurement of renewable energy in North Carolina and the PJM region. Therefore, the Commission concludes that this evidence supports issuance of the requested CPCN.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this finding is found in the application, as amended, and the testimony of the Applicant's witnesses Schultz, Montgomery, and Thienpont; and the Public Staff's witness Lawrence.

Based upon the foregoing and the entire record in this proceeding, and consistent with the foregoing findings of fact and supporting evidence and conclusions, the Commission finds good cause to grant the requested CPCN, subject to the conditions set forth herein. The amended site map filed by the Applicant on October 9, 2017, indicates that, without modifying the original project boundary, the Applicant no longer intends to place solar panels on the property adjoining the School and that it is moving the substation and potential future battery storage facility to the southwestern portion of the project footprint, on the south side of Terra Ceia Road. The Commission notes that the placement of solar panels or other equipment on property other than that identified in the application, as amended, filed and approved herein will require a further amendment of the CPCN and approval by the Commission.

IT IS, THEREFORE, ORDERED as follows:

1. That a certificate of public convenience and necessity shall be, and is hereby, issued to Wilkinson Solar LLC for the construction of a 74-MW_{AC} solar PV merchant plant electric generating facility, associated equipment, and ancillary transmission facilities;

2. That Appendix A hereto shall constitute the certificate of public convenience and necessity issued for the facility; and

3. That the certificate of public convenience and necessity is conditioned upon the following requirements:

a. That the Applicant construct and operate the facility in strict accordance with applicable laws and regulations, including any local zoning and environmental permitting requirements;

b. That the Applicant or any successor certificate holder will not assert that issuance of the CPCN in any way constitutes authority to exercise a power of eminent domain, and it will abstain from attempting to exercise such power;

c. That the CPCN shall be subject to Commission Rule R8-63(e) and all orders, rules and regulations as are now or may hereafter be lawfully made by the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of October, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. EMP-93, SUB 0

Wilkinson Solar, LLC
One South Wacker Dr., Suite 1800
Chicago, IL 60606

is hereby issued this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
PURSUANT TO G.S. 62-110.1

for construction of a 74-MW solar photovoltaic
merchant plant electric generating facility
to be commenced within three years of this Certificate

located
in Beaufort County, North Carolina, on the south side of Terra Ceia Road, between Vreugdenhil Road and Christian School Road, and the north side of Terra Ceia Road,

east of Christian School Road,

subject to the following conditions: (a) until Wilkinson Solar LLC has obtained all necessary easement(s) to connect the arrays, the CPCN should be effective only with respect to the portion of the facility proposed to be located north of Terra Ceia Road, and that Wilkinson Solar LLC shall file a letter with the Commission verifying that legal control has been obtained before beginning construction on the portion of the proposed facility south of Terra Ceia Road;
(b) Wilkinson Solar LLC will construct and operate the generating facility in strict accordance with applicable laws and regulations, including any local zoning and environmental permitting

requirements; (c) Wilkinson Solar LLC will not assert that the issuance of the certificate in any way constitutes authority to exercise any power of eminent domain, and it will abstain from attempting to exercise such power; (d) this certificate is subject to Commission Rule R8-63 and all orders, rules, regulations and conditions as are now or may hereafter be lawfully made by the Commission.

ISSUED BY ORDER OF THE COMMISSION
This the 11th day of October, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

DOCKET NO. EMP-93, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Wilkinson Solar LLC for a	)	
Certificate of Public Convenience and Necessity	)	ERRATA ORDER
to Construct a 74-MW Solar Facility in Beaufort	)	
County, North Carolina	)	

BY THE PRESIDING COMMISSIONER: On October 11, 2017, the Commission issued an Order Issuing Certificate of Public Convenience and Necessity in the above-captioned proceeding granting the application filed by Wilkinson Solar LLC for a certificate of public convenience and necessity to construct a 74-MW solar photovoltaic (PV) facility in Beaufort County, North Carolina. The certificate attached to the Order as Appendix A inadvertently included a condition not imposed in the body of the Order that was related to an issue in the case that had been resolved prior to issuance of the Order. The Presiding Commissioner, therefore, finds good case to issue this Errata Order correcting the certificate.

IT IS, THEREFORE, ORDERED that Appendix A hereto shall constitute the corrected certificate of public convenience and necessity issued for the 74-MW_{AC} solar PV merchant plant electric generating facility, associated equipment, and ancillary transmission facilities proposed to be constructed by Wilkinson Solar LLC in Beaufort County, North Carolina.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of October, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. EMP-93, SUB 0

Wilkinson Solar, LLC
One South Wacker Dr., Suite 1800
Chicago, IL 60606

is hereby issued this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
PURSUANT TO G.S. 62-110.1

for construction of a 74-MW solar photovoltaic
merchant plant electric generating facility
to be commenced within three years of this Certificate

located
in Beaufort County, North Carolina, on the south side of Terra Ceia Road, between Vreugdenhil Road and Christian School Road, and the north side of Terra Ceia Road, east of Christian School Road,

subject to the following conditions: (a) Wilkinson Solar LLC will construct and operate the generating facility in strict accordance with applicable laws and regulations, including any local zoning and environmental permitting requirements; (b) Wilkinson Solar LLC will not assert that the issuance of the certificate in any way constitutes authority to exercise any power of eminent domain, and it will abstain from attempting to exercise such power; (c) this certificate is subject to Commission Rule R8-63 and all orders, rules, regulations and conditions as are now or may hereafter be lawfully made by the Commission.

ISSUED BY ORDER OF THE COMMISSION
This the 12th day of October, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

NATURAL GAS – ADJUSTMENTS OF RATES/CHARGES

DOCKET NO. G-9, SUB 710

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Piedmont Natural Gas	)	
Company, Inc. for Annual Review of Gas	)	ORDER ON ANNUAL
Costs Pursuant to G.S. 62-133.4(c) and	)	REVIEW OF GAS COSTS
Commission Rule R1-17(k)(6)	)	

HEARD: Tuesday, October 3, 2017, at 10:00 a.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding, and Commissioners Jerry C. Dockham and James G. Patterson

APPEARANCES:

For Piedmont Natural Gas Company, Inc.:

James H. Jeffries IV, Moore & Van Allen PLLC, Bank of America Corporate Center, 100 N. Tryon Street, Suite 4700, Charlotte, North Carolina 28202

For the Using and Consuming Public:

Elizabeth D. Culpepper, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

For Carolina Utility Customers Association, Inc.:

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

BY THE COMMISSION: On August 1, 2017, pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), Piedmont Natural Gas Company, Inc. (Piedmont or Company), filed the direct testimonies and exhibits of MaryBeth Tomlinson, Manager of Gas Accounting; Michelle R. Mendoza, Director of Pipeline Services; and Sarah E. Stabley, Director of Gas Supply, Scheduling and Optimization, attesting to the prudence of the Company's gas purchasing practices and the accuracy of the Company's gas cost accounting for the twelve-month period ended May 31, 2017.

On August 4, 2017, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice. This Order established a hearing date of October 3, 2017, set prefiled testimony dates, and required the Company to give notice to its customers of the hearing on this matter.

On August 9, 2017, Carolina Utility Customers Association, Inc. (CUCA), filed a petition seeking to intervene in this docket. On August 15, 2017, the Commission issued an Order Granting Petition to Intervene.

On September 14, 2017, Piedmont filed the Supplemental Testimony and Exhibit of MaryBeth Tomlinson.

On September 18, 2017, the Public Staff filed the prefiled joint testimony of Poornima Jayasheela, Staff Accountant, Natural Gas Section, Accounting Division; Jan A. Larsen, Director, Natural Gas Division; and Julie G. Perry, Accounting Manager - Natural Gas and Transportation Section, Accounting Division (Public Staff Panel or Panel). On September 19, 2017, the Public Staff filed a revised page 9 to its prefiled testimony.

On September 21, 2017, Piedmont and the Public Staff filed a joint motion for witnesses to be excused from appearance at the expert witness hearing and requested that the prefiled testimony and exhibits of all witnesses be received into the record without requiring the appearance of the witnesses. Piedmont and the Public Staff stated that CUCA had agreed to waive cross-examination of the witnesses for Piedmont and the Public Staff, and did not otherwise object to the relief sought in their motion. The Commission granted the motion on September 25, 2017.

On September 29, 2017, the Company filed its affidavits of publication.

On October 3, 2017, the matter came on for hearing as scheduled, and all prefiled testimony and exhibits were admitted into evidence. No public witnesses appeared at the hearing.

On November 2, 2017, Piedmont and the Public Staff filed a joint motion seeking an additional seven (7) days for parties to file proposed orders and briefs in this docket, which was granted by Commission order issued on November 3, 2017.

On November 7, 2017, Piedmont and the Public Staff filed their Joint Motion to Supplement the Record in this proceeding pursuant to which they sought leave to file three revised pages to the Public Staff's prefiled direct testimony in order to correct minor errors in that testimony. That motion was allowed by Commission order dated November 8, 2017.

On November 9, 2017, Piedmont and the Public Staff filed a Joint Proposed Order.

Based on the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Piedmont is a public utility as defined in Chapter 62 of the North Carolina General Statutes and is subject to the jurisdiction and regulation of the Commission.

2. Piedmont is engaged primarily in the business of transporting, distributing, and selling natural gas to customers in North Carolina, South Carolina, and Tennessee.

3. Piedmont has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k).

4. The review period in this proceeding is twelve months ended May 31, 2017.

5. The Company properly accounted for its gas costs incurred during the review period.

6. During the review period, the Company incurred total North Carolina gas costs of $284,034,828, which was comprised of demand and storage charges of $132,821,781, commodity gas costs of $173,683,773, and other gas costs of ($22,470,726).

7. On May 31, 2017, the Company had a credit balance of $3,372,155, owed from the Company to the customers, in its Sales Customers' Only Deferred Account and a debit balance of $10,741,279, owed from the customers to the Company, in its All Customers Deferred Account.

8. During the review period, Piedmont actively participated in secondary market transactions earning actual margins of $31,613,832 for the benefit of North Carolina ratepayers.

9. Piedmont operated a gas cost hedging program on behalf of customers during the review period. Piedmont's hedging activities during the review period were reasonable and prudent.

10. On May 31, 2017, the balance in the Company's Hedging Deferred Account was a debit balance of $764,597.

11. It is appropriate for the Company to transfer the $764,597 debit balance in its Hedging Deferred Account to its Sales Customers Only Deferred Account. The combined balance for the Hedging and Sales Customers Only Deferred Accounts is a net credit balance of $2,607,558.

12. The Company has transportation and storage contracts with interstate pipelines, which provide for the transportation of gas to the Company's system, and long-term supply contracts with producers, marketers, and other suppliers.

13. The Company utilized a "best cost" gas purchasing policy during the applicable review period consisting of five main components: price of gas, security of the gas supply, flexibility of the gas supply, gas deliverability, and supplier relations.

14. The Company's gas purchasing policy and practices during the review period were prudent.

15. The Company's gas costs during the review period were prudently incurred, and the Company should be permitted to recover 100% of such prudently incurred gas costs.

16. The Company should implement the temporary rate decrement applicable to the Sales Customers Only Deferred Account and the temporary rate increments applicable to the All Customers Deferred Account proposed by Company witness Tomlinson and agreed to by the Public Staff Panel.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

The evidence supporting these findings of fact is contained in the official files and records of the Commission and the testimony of Company witnesses Tomlinson, Mendoza, and Stabley. These findings are essentially informational, procedural, or jurisdictional in nature and are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Tomlinson, Mendoza, and Stabley, and in the testimony of the Public Staff Panel. These findings are made pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

G.S. 62-133.4 requires that each natural gas utility submit to the Commission information and data for an historical twelve-month review period concerning its actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(a) establishes May 31, 2017, as the end date of the annual review period for the Company in this proceeding. Commission Rule R1-17(k)(6)(c) requires that Piedmont file weather-normalized sales volumes, workpapers, and direct testimony and exhibits supporting the information.

Company witness Tomlinson testified that the Company filed with the Commission and submitted to the Public Staff throughout the review period complete monthly accountings of the computations required by Commission Rule R1-17(k)(6)(c). Witness Tomlinson included the annual data required by Commission Rule R1-17(k)(6)(c) as Exhibit (MBT-1) to her direct testimony. The Public Staff Panel stated that they had presented the results of their review of the gas cost information filed by Piedmont in accordance with G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

Based upon the foregoing, the Commission concludes that Piedmont has complied with the procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the twelve-month review period ended May 31, 2017.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-7

The evidence supporting these findings of fact is contained in the testimony of Company witness Tomlinson and the Public Staff Panel.

Company witness Tomlinson testified that Piedmont incurred total North Carolina gas costs of $284,034,828 during the review period, which was comprised of demand and storage charges of $132,821,781, commodity gas costs of $173,683,773, and other gas costs of ($22,470,726).

Company witness Tomlinson's prefiled testimony and exhibits reflected a credit balance of $3,372,155 in its Sales Customers Only Deferred Account and a debit balance of $10,741,279 in its All Customers Deferred Account as of May 31, 2017. The Public Staff Panel agreed with these balances and testified that the Company properly accounted for its gas costs incurred during the review period.

Based upon the foregoing, the Commission concludes that the Company properly accounted for its gas costs incurred during the review period. The Commission also concludes that the appropriate level of total North Carolina gas costs incurred for this proceeding is $284,034,828. The Commission further concludes that the appropriate balances of the Company's deferred accounts as of May 31, 2017, are a credit balance of $3,372,155, owed from the Company to the customers, in its Sales Customers Only Deferred Account, and a debit balance of $10,741,279, owed from the customers to the Company, in its All Customers Deferred Account.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the testimony of Company witness Stabley and the Public Staff Panel.

Company witness Stabley provided testimony on the process that Piedmont utilized and the market intelligence that was evaluated during the review period to determine the prices charged for off-system sales. Witness Stabley explained that the process and information used by Piedmont in pricing off-system sales depends upon the location of the sale, term and type of the sale, and prevailing market conditions at the time of the sale. Witness Stabley stated that for long-term delivered sales (longer than one month), Piedmont generally solicits bids from potential buyers and, if acceptable, awards volumes based on bids received and its evaluation. Witness Stabley further stated that, for short-term transactions (daily or monthly), Piedmont monitors prices and volumes on the Intercontinental Exchange, as well as by talking to various market participants and, for less liquid trading points, estimating prices based on price relationships with more liquid points. The Company also evaluates the amount of supply available for sale and weighs that against current market conditions in formulating its sales strategy.

The Public Staff Panel testified that the Company earned actual total company margins of $49,531,908 on secondary market transactions and credited the All Customers Deferred Account in the amount of $31,613,832 for the benefit of North Carolina ratepayers [($49,496,547 x NC demand allocator x 75% ratepayer sharing percent) + (100% of Duke Energy Carolinas/Duke Energy Progress secondary market transactions of $35,361 x NC demand allocator)], in accordance with the Commission's Order Approving Stipulation issued on December 22, 1995, in Docket No. G-100, Sub 67, and the Order approving the merger between Piedmont and Duke Energy Corporation, Order Approving Merger Subject to Regulatory Conditions and Code of Conduct (Merger Order), Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682 (September 29, 2016). The Merger Order provides that customers of Piedmont, Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC (collectively, utility affiliates), will receive 100% of the net proceeds from secondary market transactions between the utility affiliates, rather than the customary 75% for customers and 25% for the utility affiliates. The margins earned were a result of Piedmont's participation in asset management arrangements, capacity releases, and off system sales.

Based on the foregoing, the Commission concludes that Piedmont actively participated in secondary market transactions, resulting in $31,613,832 of margin for the benefit of North Carolina ratepayers during the review period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-11

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Tomlinson and Stabley and the Public Staff Panel.

Company witness Tomlinson stated in her testimony that the Company had a debit balance of $764,597 in its Hedging Deferred Account at May 31, 2017. The Public Staff Panel testified that the net hedging costs were composed of Economic Gains on Closed Positions of ($1,689,560), Premiums Paid of $2,234,893, Brokerage Fees and Commissions of $38,859, and Interest on the Hedging Deferred Account of $180,405.

Company witness Stabley testified that Piedmont's Hedging Plan accomplished its goal of providing an insurance policy to reduce gas cost volatility for customers in the event of a gas price fly up. Witness Stabley testified that the Company did not make any changes to its Hedging Plan during the review period. Witness Stabley further testified that the Company continues to utilize storage as a physical hedge to stabilize cost, and that the Company's Equal Payment Plan, the use of the Purchased Gas Adjustment benchmark price, and deferred gas cost accounting also provide a smoothing effect on gas prices.

The Public Staff Panel testified that its review of the Company's hedging activities is performed on an ongoing basis and includes analysis and evaluation of information contained in several documents and other data. These include the Company's monthly hedging deferred account reports, detailed source documentation, workpapers supporting the derivation of the maximum targeted hedge volumes for each month, periodic reports on the status of hedge coverage for each month, and periodic reports on the market values of the various financial instruments used by the Company to hedge. In addition, the Public Staff reviewed monthly Hedging Program Status Reports, monthly reports reconciling the Hedging Program Status Report and the hedging deferred account report, and minutes from the meetings of Piedmont's Energy Price Risk Management Committee (EPRMC). Also included in the Public Staff's review were minutes from the meetings of the Piedmont Board of Directors and its committees that pertain to hedging activities, reports and correspondence from the Company's internal and external auditors, hedging plan documents, communications with Company personnel regarding key hedging events and plan modifications under consideration by the EPRMC, and the testimony and exhibits of the Company's witnesses in the annual proceeding.

The Public Staff Panel concluded that Piedmont's hedging activities were reasonable and prudent and recommended that the $764,597 debit balance in the Hedging Deferred Account as of the end of the review period be transferred to the Sales Customers Only Deferred Account. Based on this recommendation, the Panel stated that the combined balance in the Sales Customers Only Deferred Account as of May 31, 2017, is a net credit balance owed by the Company of $2,607,558.

Based on the testimony and exhibits provided by Piedmont and the Public Staff, the Commission finds that Piedmont's hedging program has met the objective of contributing to the mitigation of gas price volatility and avoiding rate shock to customers. The Commission concludes that Piedmont's hedging activities were reasonable and prudent and the $764,597 debit balance in the Hedging Deferred Account as of the end of the review period should be transferred to the Sales Customers Only Deferred Account. The combined balance for the Hedging and Sales Customers Only Deferred Accounts is a net credit balance of $2,607,558, owed to the customers from the Company.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-15

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Stabley and Mendoza, and the Public Staff Panel.

Company witness Stabley testified that the Company maintains a "best cost" gas purchasing policy. This policy consists of five main components: price of the gas; security of the gas supply; flexibility of the gas supply; gas deliverability; and supplier relations. Witness Stabley testified that all of these components are interrelated and that the Company weighs the relative importance of each of these factors in developing its overall gas supply portfolio to meet the needs of its customers.

Witness Stabley further testified that the Company purchases gas supplies under a diverse portfolio of contractual arrangements with a number of reputable gas producers and marketers. In general, under the Company's firm gas supply contracts, Piedmont may pay negotiated reservation fees for the right to reserve and call on firm supply service up to a maximum daily contract quantity (nominated either on a monthly or daily basis), with market-based commodity prices tied to indices published in industry trade publications. Some of these firm contracts are for winter only (peaking or seasonal) service and some provide for 365 day (annual) service. Firm gas supplies are purchased for reliability and security of service and are generally priced on a reservation fee basis according to the amount of nomination flexibility built into the contract with daily swing service generally being more expensive than monthly baseload service.

Witness Stabley testified that the Company identifies the volume and type of supply that it needs to fulfill its market requirements and generally solicits requests for proposals from a list of suppliers that the Company continuously updates as potential suppliers enter and leave the market place. The type of supply is classified as either baseload or swing. Witness Stabley stated that swing supplies priced at first of month indices command the highest reservation fees because suppliers incur all the price risk associated with market volatility during the delivery period. Keep-whole contracts require the Company to reimburse suppliers for the difference between first of the month index prices and lower daily market prices if the Company does not take its full contractual volume.

Witness Stabley testified that because the Company assumes the volatility risk associated with falling prices, a lower reservation fee is warranted. Lower reservation fees are also associated with swing contracts based upon daily market conditions since both buyer and seller assume the risk of daily market volatility. Witness Stabley stated that after forecasting the ultimate cost delivered to the city gate for each point of supply and evaluating the cost of the reservation fees associated with each type of supply and its corresponding bid, the Company makes a "best cost" decision on which type of supply and supplier best fulfills its needs. Company witness Stabley also testified regarding the current U.S. supply situation and the various pricing alternatives available, such as fixed prices, monthly market indexing, and daily spot market pricing.

Witness Stabley also described how the interrelationship of the five factors affects the Company's construction of its gas supply and capacity portfolio under its best cost policy. The long-term contracts, supplemented by long-term peaking services and storage, generally are aligned with the firm market; the short-term spot gas generally serves the interruptible market. In order to weigh and consider the five factors, the Company stays abreast of current issues facing the natural gas industry by intervening in all major Federal Energy Regulatory Commission (FERC) proceedings involving its pipeline transporters, maintaining constant contact with existing and potential suppliers, monitoring gas prices on a real-time basis, subscribing to industry literature, following supply and demand developments, and attending industry seminars. Witness Stabley further testified that the Company did not make any changes in its best cost gas purchasing policies or practices during the test period. Witnesses Mendoza and Stabley also indicated that during the past year the Company has taken several additional steps to manage its costs, including, actively participating in proceedings at the FERC and other regulatory agencies that could reasonably be expected to affect the Company's rates and services, promoting more efficient peak day use of its system, and utilizing the flexibility within its existing supply and capacity contracts to purchase and dispatch gas, and release capacity in the most cost effective manner.

Company witness Mendoza testified about the market requirements of Piedmont's North Carolina customers and the acquisition of capacity to serve those markets. Witness Mendoza also testified that the Company expects the economy to continue recovering and to result in potentially increasing residential, commercial and industrial demand, and in turn, result in greater firm temperature sensitive requirements that will require firm sales service from the Company.

Witness Mendoza further testified that Piedmont and the natural gas industry have not seen evidence that conservation/reduced usage occurs during design day conditions. For that reason, witness Mendoza testified that Piedmont is confident the conservative approach to design day forecasting is the most prudent approach.

Witness Mendoza testified that the Company currently believes that it has sufficient supply and capacity rights to meet its near term customer needs into the 2017-2018 winter period timeframe but that growth projections begin to show a capacity deficit beginning in the 2019-2020 timeframe if the Atlantic Coast Pipeline (ACP) capacity does not go into service as projected. Witness Mendoza testified that in light of prospective growth requirements, Piedmont reviewed new capacity options in addition to continuous monitoring of interstate pipeline and storage capacity offerings. Witness Mendoza further stated that although the Company subscribed to the Leidy Southeast Expansion Project (Leidy Southeast) of Transcontinental Gas Pipe Line Company, LLC (Transco), for 100,000 dekatherms (dts) per day of year-round capacity and 20,000 dts per day on Transco's Virginia Southside Expansion Project (Virginia Southside), the Company signed a Precedent Agreement with ACP in October of 2014 for 160,000 dts per day of firm capacity to be provided by ACP, which is scheduled to go in service in November of 2019. Witness Mendoza testified that previously contracted capacity for Leidy Southeast and Transco's Virginia Southside went into service late 2015 and 2016.

Witness Mendoza testified that capacity additions are acquired in "blocks" of additional transportation, storage, or liquefied natural gas capacity, as they become needed, to ensure Piedmont's ability to serve its customers based on the options available at that time. Witness Mendoza explained that as a practical matter, this means that at any given moment in time, Piedmont's actual capacity assets will vary somewhat from its forecasted demand capacity requirements. Witness Mendoza also stated that this aspect of capacity planning is unavoidable but Piedmont attempts to mitigate the impact of any mismatch through its use of bridging services, capacity release, and off-system sales activities.

The Public Staff Panel testified that they had reviewed the testimony and exhibits of the Company's witnesses, the monthly operating reports, and the gas supply and pipeline transportation and storage contracts, as well as the Company's responses to the Public Staff's data requests. Based on this review, the Panel testified that the Company's gas costs were prudently incurred.

The Public Staff Panel further testified that, although the scope of Commission Rule R1-17(k) is limited to a historical review period, they also considered other information in order to anticipate the Company's requirements for future needs, including design day estimates, forecasted load duration curves, forecasted gas supply needs, projection of capacity additions and supply changes, and customer load profile changes.

Based on the foregoing, the Commission concludes that the Company's gas costs incurred during the review period were reasonable and prudently incurred and that the Company should be permitted to recover 100 percent of its prudently incurred gas costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding of fact is contained in the testimony of Company witness Tomlinson and the Public Staff Panel.

Company witness Tomlinson testified that based on the Company's deferred accounts end-of-period balances, as reflected on revised Tomlinson Exhibit_(MBT-1), she recommended that the increments/decrements to Piedmont's rates be placed into effect for a period of twelve months after the effective date of the final order in this proceeding.

The Public Staff Panel testified that they had reviewed Company witness Tomlinson's proposed temporary rate decrement applicable to the Sales Customers Only Deferred Account balance in Tomlinson Revised Exhibit_(MBT-4) and the proposed temporary rate increments applicable to the All Customers Deferred Account balance in Tomlinson Revised Exhibit_(MBT-3) and agreed that they should be implemented. The Panel also recommended that Piedmont remove all temporary rates that were implemented in Docket No. G-9, Sub 690, Piedmont's last annual review proceeding.

The Public Staff Panel further testified that Piedmont monitor the balances in both the All Customers and Sales Customers Only Deferred Accounts, and, if needed, Piedmont file an application for authority to implement new temporary increments or decrements through the Purchased Gas Adjustment mechanism in order to keep the deferred account balances at reasonable levels.

Based on the foregoing, the Commission concludes that it is appropriate for the Company to remove the temporary rates that were implemented in Docket No. G-9, Sub 690, and implement the temporaries in the instant docket.

IT IS, THEREFORE, ORDERED as follows:

1. That the Company's accounting for gas costs during the twelve-month period ended May 31, 2017, is approved;

2. That the gas costs incurred by Piedmont during the twelve-month period ended May 31, 2017, including the Company's hedging costs, were reasonably and prudently incurred, and Piedmont is hereby authorized to recover 100% of its gas costs incurred during the period of review;

3. That the Company shall remove the existing temporaries that were implemented in Docket No. G-9, Sub 690, and implement the rate decrement for the Sales Customers Only Deferred Account and the temporary rate increments for the All Customers Deferred Account, as found appropriate herein, effective for service rendered on and after the first day of the month following the date of this Order;

4. That Piedmont shall give notice to its customers of the rate changes allowed in this Order; and

5. That Piedmont shall file revised tariffs within five (5) days of the date of this Order implementing the rate changes authorized in Ordering Paragraph No. 3 above.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of December, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. G-5, SUB 578

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Public Service Company of	)	
North Carolina, Inc. for Annual Review of	)	ORDER ON ANNUAL
Gas Costs Pursuant to G.S. 62-133.4(c) and	)	REVIEW OF GAS COSTS
Commission Rule R1-17(k)(6)	)	

HEARD: Tuesday, August 8, 2017, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding, Commissioner Lyons Gray, and Commissioner Daniel G. Clodfelter

APPEARANCES:

For Public Service Company of North Carolina, Inc.:

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

For Carolina Utility Customers Association, Inc.:

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

For the Using and Consuming Public:

Gina C. Holt, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: On June 1, 2017, pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), Public Service Company of North Carolina, Inc. (PSNC or Company), filed the direct testimony and exhibits of Candace A. Paton, Rates & Regulatory Manager for PSNC, and Rose M. Jackson, General Manager – Supply & Asset Management for SCANA Services, Inc., in connection with the annual review of PSNC's gas costs for the 12-month period ended March 31, 2017.

On June 6, 2017, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. This Order established a hearing date of Tuesday, August 8, 2017, set prefiled testimony dates, and required the Company to give notice to its customers of the hearing on this matter.

On June 20, 2017, the Carolina Utility Customers Association, Inc. (CUCA) filed a petition seeking to intervene in this docket. On June 21, 2017, the Commission issued an Order granting CUCA's petition to intervene.

On July 24, 2017, the Public Staff filed the direct testimony of Neha R. Patel, Utilities Engineer, Natural Gas Division; Julie G. Perry, Manager of the Natural Gas Section, Accounting Division; and Sonja M. Johnson, Staff Accountant, Accounting Division.

On August 4, 2017, PSNC filed an unopposed Motion to Excuse Witnesses and requested that the prefiled testimony and exhibits of all witnesses be received into the record without requiring the appearance of such witnesses. The Commission granted the motion on August 7, 2017.

On August 7, 2017, the Company filed its affidavits of publication.

On August 8, 2017, the matter came on for hearing as scheduled, and all prefiled testimony and exhibits were admitted into evidence. No public witnesses appeared at the hearing.

On September 8, 2017, the Joint Proposed Order of PSNC and the Public Staff was filed.

Based on the testimony and exhibits received into evidence and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. PSNC is a corporation duly organized and existing under the laws of the State of South Carolina, having its principal office and place of business in Gastonia, North Carolina. PSNC operates a natural gas pipeline system for the transportation, distribution, and sale of natural gas to approximately 550,000 customers in the State of North Carolina.

2. PSNC is engaged in providing natural gas service to the public and is a public utility as defined in G.S. 62-3(23), subject to the jurisdiction of this Commission.

3. PSNC has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of such statute and rule.

4. The review period in this proceeding is the twelve months ended March 31, 2017.

5. During the review period, PSNC incurred total gas costs of $154,728,840, comprised of demand and storage charges of $93,299,905, commodity gas costs of $102,332,518, and other gas costs of ($40,903,584).

6. In compliance with the Commission's order in Docket No. G-100, Sub 67, the Company credited 75% of the net compensation from secondary market transactions, which amounted to $36,377,357, to its All Customers Deferred Account.

7. As of March 31, 2017, the Company had a credit balance (owed from the Company to customers) of $6,021,495 in its Sales Customers Only Deferred Account and a credit balance of $7,449,531 in its All Customers Deferred Account.

8. It is appropriate for the Company to credit the All Customers Deferred Account for the July 2016 demand payment to the City of Monroe once the refund is issued to PSNC.

9. The Company properly accounted for its gas costs incurred during the review period.

10. PSNC's hedging activities during the review period were reasonable and prudent.

11. As of March 31, 2017, the Company had a credit balance of $556,941 in its Hedging Deferred Account.

12. It is appropriate for the Company to transfer the $556,941 credit balance in the Hedging Deferred Account to its Sales Customers Deferred Account. The combined balance for the Hedging and Sales Customers Deferred Accounts is a net credit balance of $6,578,436, owed to customers.

13. PSNC has adopted a gas supply policy that it refers to as a "best cost" supply strategy. This gas supply acquisition policy is based upon three primary criteria: supply security, operational flexibility, and the cost of gas.

14. PSNC has firm transportation and storage contracts with interstate pipelines, which provide for the transportation of gas to the Company's system, and both long-term and supplemental short-term supply contracts with producers, marketers, and other suppliers.

15. The gas costs incurred by PSNC during the review period were prudently incurred, and the Company should be permitted to recover 100% of such prudently incurred gas costs.

16. As proposed by PSNC witness Paton and agreed to by the Public Staff, the Company should not implement any temporary rate changes in the instant docket at this time.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

These findings are essentially informational, procedural, or jurisdictional in nature and were not contested by any party. They are supported by information in the Commission's public files and records and the testimony and exhibits filed by the witnesses for PSNC and the Public Staff.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

The evidence supporting these findings of fact is contained in the testimony of PSNC witnesses Jackson and Paton, and the testimony of Public Staff witnesses Patel and Johnson. These findings are based on G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

G.S. 62-133.4 requires that PSNC submit to the Commission information and data for an historical 12-month review period, including PSNC's actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(c) requires that PSNC file weather normalization, sales volume data, work papers, and direct testimony and exhibits supporting the information.

Witness Paton testified that Rule R1-17(k)(6) requires PSNC to submit to the Commission on or before June 1 of each year certain information with supporting work papers based on the 12-month period ending March 31. Witness Paton indicated that the Company had filed the required information. Witness Paton also stated that the Company had provided to the Commission and the Public Staff on a monthly basis the gas cost and deferred gas cost account information required by Commission Rule R1-17(k)(5)(c). Witnesses Patel and Johnson presented the results of their review of the gas cost information filed by PSNC in accordance with G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

Based on the foregoing, the Commission concludes that PSNC has complied with the procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the 12-month review period ended March 31, 2017.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-9

The evidence supporting these findings of fact is found in the testimony and exhibits of PSNC witness Paton and the testimony of Public Staff witnesses Patel and Johnson.

PSNC witness Paton's exhibits show that the Company incurred total gas costs of $154,728,840 during the review period, which was comprised of demand and storage costs of $93,299,905, commodity gas costs of $102,332,518, and other gas costs of ($40,903,584). Public Staff witness Johnson confirmed that total gas costs for the review period ended March 31, 2017, were $154,728,840.

Public Staff Witness Johnson stated that the Company recorded $48,503,142, of margin on secondary market transactions, including capacity release transactions and storage management arrangements, during the review period. Of this amount, $36,377,357 was credited to the All Customers Deferred Account for the benefit of ratepayers.

PSNC witness Paton's prefiled testimony and exhibits reflected a Sales Customers Only Deferred Account credit balance of $6,021,495 (owed to customers) and a credit balance (owed to customers) of $7,449,531 in its All Customers Deferred Account as of March 31, 2017. Public Staff witness Johnson agreed with these balances and testified that PSNC properly accounted for its gas costs during the review period.

Public Staff Witness Johnson stated that PSNC inadvertently made an extra demand charge payment to the City of Monroe in July 2016, in the amount of $97,363. Witness Johnson further stated that PSNC agreed to credit the All Customers Deferred Account to reverse the charge to demand and storage charges once the refund is issued from the City of Monroe.

Based upon the foregoing, the Commission concludes that the Company properly accounted for its gas costs incurred during the review period. The Commission also concludes that the appropriate level of total gas costs incurred by PSNC for this proceeding is $154,728,840. The Commission further concludes that the appropriate balances as of March 31, 2017, are a credit balance of $6,021,495, owed to customers, in its Sales Customers Only Deferred Account and a credit balance of $7,449,531, owed to customers, in its All Customers Deferred Account.

The Commission further concludes that it is appropriate for PSNC to credit the All Customers Deferred Account to reverse the charge to demand and storage charges once the refund is issued from the City of Monroe.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-12

The evidence for these findings of fact is contained in the testimony of PSNC witnesses Paton and Jackson and the testimony of Public Staff witnesses Perry and Johnson.

PSNC witness Paton testified that the Company's Hedging Deferred Account balance for the 12-month review period ended March 31, 2017, was $556,941, a net credit balance, due to customers. Public Staff witness Perry testified that this balance was composed of: Economic Gains - Closed Positions of ($2,824,398); Premiums Paid of $2,072,240; Brokerage Fees and Commissions of $39,885; and Interest on the Hedging Deferred Account of $155,361. Public Staff witness Perry further stated that the hedging charges resulted in an annual credit of $0.90 for the average residential customer which equates to approximately $0.07 per month. Witness Perry also testified that PSNC's weighted average hedged cost of gas for the review period was $2.86 per dekatherm (dt).

PSNC witness Jackson testified that the primary objective of PSNC's hedging program has always been to help mitigate the price volatility of natural gas for PSNC's firm sales customers at a reasonable cost. She further testified that PSNC's hedging program meets this objective by having financial instruments such as call options or futures in place to mitigate, in a cost effective manner, the impact of unexpected or adverse price fluctuations to its customers.

PSNC witness Jackson testified that the hedging program provides protection from higher prices through the purchase of call options for up to 25% of PSNC's estimated sales volume. Witness Jackson further stated that in order to help control costs, the call options are purchased at a price no higher than 10% of the underlying commodity price. She also stated that PSNC limits its hedging to a 12-month future time period, which allows PSNC to obtain more favorable option pricing terms and better react to changing market conditions.

PSNC witness Jackson explained that PSNC's hedging program continues to utilize two proprietary models developed by Kase and Company that assist in determining the appropriate timing and volume of hedging transactions. She stated that the total amount available to hedge is divided equally between the two models.

PSNC witness Jackson further testified that no changes were made to PSNC's hedging program during this review period. Witness Jackson stated that PSNC will continue to analyze and evaluate its hedging program and implement changes as warranted.

Public Staff witness Perry stated that her review of the Company's hedging activities involves an ongoing analysis and evaluation of the Company's monthly hedging deferred account reports, detailed source documentation, work papers supporting the derivation of the maximum targeted hedge volumes for each month, periodic reports on the status of hedge coverage for each month, and periodic reports on the market values of the various financial instruments used by the Company to hedge. In addition, the Public Staff reviews monthly Hedging Program Status Reports, monthly reports reconciling the Hedging Program Status Report and the hedging deferred account report, minutes from the meetings of SCANA's Risk Management Committee (RMC), minutes from the meetings of the Board of Directors and its committees that pertain to hedging activities. Further, the review includes reports and correspondence from the Company's internal and external auditors, hedging plan documents, communications with Company personnel regarding key hedging events and plan modifications under consideration by SCANA's RMC, and the testimony and exhibits of the Company's witnesses in the annual review proceeding. Witness Perry testified that based on her analysis of what was reasonably known or should have been known at the time the Company made its hedging decisions affecting the review period, as opposed to the outcome of those decisions, she concluded that the Company's hedging decisions were prudent.

Public Staff witness Perry further testified that the $556,941 credit balance in the Hedging Deferred Account as of the end of the review period should be transferred to the Sales Customers Only Deferred Account. Based on this recommendation, Public Staff witness Johnson stated that the appropriate balance in the Sales Customers Only Deferred Account as of March 31, 2017, after the hedging balance transfer, should be a credit balance of $6,578,436, owed to customers by the Company.

Based on the evidence in the testimony and exhibits provided by PSNC and the Public Staff, the Commission finds that PSNC's hedging program has met the objective of contributing to the mitigation of gas price volatility and avoiding rate shock to customers. The Commission concludes that PSNC's hedging activities during the review period were reasonable and prudent and that the $556,941 credit balance in the Hedging Deferred Account as of the end of the review period should be transferred to the Company's Sales Customers Only Deferred Account. The Commission finds that the appropriate combined balance for the Hedging and Sales Customers Only Deferred Accounts is a credit balance of $6,578,436.

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

The evidence for these findings of fact is found in the testimony of PSNC witness Jackson and the testimony of Public Staff witness Patel.

PSNC witness Jackson testified that the most appropriate description of PSNC's gas supply acquisition policy would be a "best cost" supply strategy, which is based on three primary criteria: supply security, operational flexibility, and cost of gas. PSNC witness Jackson stated that security of supply is the first and foremost criterion, which refers to the assurance that the supply of gas will be available when needed. Witness Jackson also testified that supply security is especially important for PSNC's firm customers, who have no alternate fuel source. Witness Jackson went on to state that supply security is obtained through PSNC's diverse portfolio of suppliers, receipt points, purchase quantity commitments, and terms. She also testified that potential suppliers are evaluated on a variety of factors, including past performance, creditworthiness, available terms, gas deliverability options, and supply location.

PSNC witness Jackson testified that the second criterion is maintaining the necessary operational flexibility in the gas supply portfolio that will enable PSNC to react to unpredictable weather and the changing requirements of industrial customers coupled with their ability to burn other fuels. She noted that PSNC's gas supply portfolio as a whole must be capable of handling the monthly, daily, and hourly changes in customer demand needs. Witness Jackson also testified that operational flexibility largely results from PSNC's gas supply agreements having different purchase commitments and swing capabilities (for example, the ability to adjust purchased gas within the contract volume on either a monthly or daily basis) and from PSNC's injections into and withdrawals out of storage.

In regard to the third criterion, cost of gas, PSNC witness Jackson stated that in evaluating costs it is important to consider not only the actual commodity cost, but also any transportation-related charges such as reservation, usage, and fuel charges. She further stated that PSNC routinely requests gas supply bids from suppliers to help ensure the most cost-effective proposals. Witness Jackson also testified that in securing natural gas supply for its customers, PSNC is committed to acquiring the most cost-effective supplies while maintaining the necessary security and operational flexibility to serve the needs of its customers. She further testified that PSNC has developed a gas supply portfolio made up of long-term agreements and supplemental short-term agreements with a variety of suppliers, including both producers and independent marketers.

PSNC witness Jackson testified that the majority of PSNC's interstate pipeline capacity is obtained from Transcontinental Gas Pipeline Company, LLC (Transco), the only interstate pipeline with which PSNC has a direct connection. The Company also has a backhaul transportation arrangement with Transco to schedule deliveries of gas from pipelines and storage facilities downstream of PSNC's system, as well as transportation and/or storage service agreements with Dominion Transmission, Inc., Columbia Gas Transmission, LLC, Texas Gas Transmission, LLC, East Tennessee Natural Gas LLC, Dominion Cove Point LNG, LP, Saltville Gas Storage Company, L.L.C., and Pine Needle LNG Company, LLC.

PSNC witness Jackson testified that PSNC has engaged in the following activities to lower gas costs while maintaining security of supply and delivery flexibility:

1. PSNC continues to optimize the flexibility available within its supply and capacity contracts to realize their value;

2. PSNC monitored and intervened in matters before the Federal Energy Regulatory Commission whose actions could impact PSNC's rates and services to its customers;

3. PSNC has continued to work with its industrial customers to transport customer-acquired gas;

4. PSNC routinely communicates directly with customers, suppliers, and other industry participants, and actively monitors developments in the industry;

5. PSNC has frequent internal discussions concerning gas supply policy and major purchasing decisions;

6. PSNC utilizes deferred gas cost accounting to calculate the Company's benchmark cost of gas to provide a smoothing effect on gas price volatility; and,

7. PSNC conducts a hedging program to help mitigate price volatility.

PSNC Witness Jackson testified that in August 2016 PSNC responded to an open season solicitation with a bid for 25,000 dts per day of firm backhaul transportation service on Transco's mainline with a primary path from the receipt point at Transco's Station 210 (Mercer County, New Jersey) to a delivery point at Station 65 (St. Helena Parish, Louisiana) for the period November 2016 through March 2017. The bid was accepted at the maximum applicable tariff rates. PSNC acquired this capacity in order to obtain more reliable deliverability of the Dominion and Columbia storage services on non-peak days during the winter season to ensure each storage facility's minimum turnover requirement could be achieved.

PSNC witness Jackson testified that the projected design-day demand of PSNC's firm customers is calculated using a statistical modeling program prepared by SCANA Services Resource Planning personnel. She further explained that the model assumes a 50 heating degree-day (HDD) on a 60 degree Fahrenheit base and uses historical weather to estimate peak-day demand. Witness Jackson also testified that PSNC presented its forecasted firm peak-day demand requirements for the review period and for the next five winter seasons. She further explained that the assets available to meet PSNC's firm peak-day requirements include year-round, seasonal, and peaking capabilities and consist of firm transportation and storage capacity on interstate pipelines as well as the peaking capability of PSNC's on-system liquefied natural gas facility.

Public Staff witness Patel testified that she had reviewed the testimony and exhibits of the Company's witnesses; monthly operating reports; gas supply and pipeline transportation and storage contracts; and the Company's responses to the Public Staff's data requests. She further testified that the Public Staff had independently calculated the customer load profile and peak design day demand using current (review period) data and the results of the Public Staff's analysis are slightly higher, but are comparable to PSNC's levels reflected in Jackson Exhibit 1. She concluded that, in her opinion, PSNC's gas costs were prudently incurred for the 12-month review period ending March 31, 2017.

Based upon the foregoing, the Commission concludes that the Company's gas costs incurred during the review period ended March 31, 2017, were reasonable and prudently incurred and that the Company should be permitted to recover 100% of its prudently incurred gas costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this finding of fact is found in the testimony of PSNC witness Paton and the testimony of Public Staff witness Patel.

PSNC witness Paton testified that the Company was not proposing new temporary rate increments or decrements at this time. Specifically, PSNC witness Paton testified that although the Company had an over-collection in the All Customers Deferred Account at the end of the review period, it was not proposing temporary decrements to refund this balance. Witness Paton further testified that the Company is in a similar position as it was in last year's Annual Review of Gas Costs (ARGC) in Docket No. G-5, Sub 568, when it had an over-collection of $6.7 million in the All Customers Deferred Account at the end of the review period and projected an under-collection of $13.7 million by the end of October 2016. The actual under-collection at the end of October 2016 was $11.2 million.

Witness Paton testified that because PSNC's annual review period is the twelve months ended March 31, it is not unusual for the deferred account balance to be an over-collection. PSNC incurs fixed gas costs evenly throughout the year, but recovery of fixed gas costs is seasonal. Approximately seventy-five percent of the fixed gas costs billed during the review period were collected in the five-month period of November through March. Witness Paton testified that because of the seasonality of the balance of this account, rather than proposing a rate decrement based on a single point in time, PSNC believes it is better to monitor the actual and projected balance in the All Customers Deferred Account and file to request temporary increments or decrements as applicable.

Public Staff witness Patel testified that the All Customers Deferred Account credit balance of $7,449,531 had decreased to $6,310,197 by the end of April 2017, and furthermore, PSNC estimated the balance will "flip" to a debit balance (owed from customers to the Company) of approximately $11.8 million by the end of October 2017. Witness Patel noted that it is not unusual to have a change in the deferred account balances since fixed gas costs are typically over-collected during the winter period when throughput is higher due to heating load, and under-collected during the summer when throughput is lower.

Based on the testimony discussed above, the Commission notes that it is commonplace for the Company to over-collect during the winter months and under-collect during summer months and recognizes that this is what occurred during the prior review period ended March 31, 2016, in Docket No. G-5, Sub 568. Had the Commission ordered a rate decrement in that proceeding, the effect would have been counterproductive, due to the fact that by the time temporary decrements would have gone into effect in November 2016, the Company was under-collected, and it would have had to file a petition to remove the decrement and perhaps implement an increment.

The Commission concludes that the same would be true in this docket. If the Commission were to require decrements, by the time rates go into effect in November the Company would likely be under-collected and the decrements would exacerbate that position. In addition to the testimony presented by the Company and the Public Staff at the hearing regarding the projected changes in the deferred account balances, the Commission takes notice that PSNC's July 2017 deferred gas cost account report filed in Docket No. G-5, Sub 574 on August 22, 2017, reflects an All Customers Deferred Account debit balance of $1,519,640. Therefore, the Commission concludes that not requiring decrements applicable to the All Customers Deferred Account at this time is reasonable.

Regarding the credit balance in the Sales Customers Deferred Account, Witness Paton testified that the Company proposes to continue its practice of taking into consideration the balance in the Sales Customers Only Deferred Account when evaluating whether to file for a change in the benchmark cost of gas and that making periodic, and smaller, adjustments in the benchmark cost of gas is preferable to making one adjustment annually based on the over- or under-collection in the commodity cost of gas that may exist as of the end of the review period.

Public Staff witness Patel testified that the Sales Customers Only Deferred Account reflected a net credit balance of $6,578,436 owed by the Company to customers and that PSNC was in a similar position in previous annual reviews. Public Staff witness Patel further stated that the Company proposed not to place a decrement in rates for the recovery of the credit balance but to manage it by using the purchased gas adjustment mechanism, pursuant to G.S. 62-133.4, which PSNC has previously used for this purpose. Witness Patel concluded that in the instant case it would be better if PSNC monitored the All Customers Deferred Account and filed a request to implement temporary increments or decrements as applicable, and therefore, agreed with the Company's proposals.

During the hearing, the Commission noted the requirements of G.S. 62-133.4(c), which states, in pertinent part:

> [T]he Commission, upon notice and hearing, shall compare the utility's prudently incurred costs with costs recovered from all the utility's customers that it served during the test period. If those prudently incurred costs are greater or less than the recovered costs, the Commission shall, subject to G.S. 62-158, require the utility to refund any overrecovery by credit to bill or through a decrement in its rates and shall permit the utility to recover any deficiency through an increment in its rates.

The Commission noted that in past dockets the Commission has on occasion exercised its discretion and has not required LDCs to implement a rate decrement when, as a matter of timing, it appeared that the LDC's overrecovery would be resolved shortly, or that the overrecovery could potentially become an underrecovery if a rate decrement was implemented.

The Commission further noted that in PSNC's last cost of gas review, Docket No. G-5, Sub 568, there was an overrecovery of almost $5 million in the Sales Deferred Account at the end of the last review period on March 31, 2016. In that docket, witness Paton testified, similar to her testimony here, that

> [T]he Company believes that making periodic, and smaller, adjustments in the benchmark cost of gas is preferable to making one adjustment annually based on the over- or under-collection in commodity cost of gas that may exist as of the end of the review period.

The Commission further noted, however, that during the review period in the present docket, PSNC made only one adjustment to its benchmark cost of gas, in Docket No. G-5, Sub 572. That adjustment raised the benchmark from $2.25 per dekatherm to $3.00 per dekatherm, effective January 1, 2017, and that according to the Commission's records, PSNC's monthly Sales Customers Deferred Account balance, including the monthly Hedging Account balance, was not brought to zero at the end of any month during the review period in this docket. Further, according to Public Staff witness Johnson's testimony, the Sales Customers Deferred Account had a credit balance owed to customers of $6.5 million, as of March 31, 2017.

The Commission requested, based on G.S. 62-133.4(c) and the record recounted above, that the parties address in post-hearing briefs why they maintain that it is again appropriate for the Commission to forego ordering a rate decrement, and, instead, allow PSNC to use the Purchase Gas Adjustment mechanism to balance the Sales Customers Deferred Account. However, no party filed a post-hearing brief. Instead, in PSNC's and the Public Staff's Joint Proposed Order (JPO), PSNC and the Public Staff contend that not requiring decrements at this time is consistent with G.S. 62-133.4 because even though subsection (c) of the statute states that the Commission "shall" require a refund in such cases, subsection (b) states that a utility may apply for permission to change its rates to track changes in the cost of natural gas supply and transportation and allows the Commission, without a hearing, to issue an order allowing such rate changes to become effective "simultaneously with the effective date of the change in the cost of natural gas or at any other time ordered by the Commission." In addition, subsection (d) states that nothing in the statute prohibits the Commission from "investigating and changing unreasonable rates as authorized by this Chapter ...."

In addition, PSNC and the Public Staff note that G.S. 62-133.4(c) requires the Commission to "compare the utility's prudently incurred costs with costs recovered from all the utility's customers", and contend that the statute does not require the Commission to look at incurred costs by category of costs. Consequently, they submit, it is reasonable to look at the balances in the Sales Customers and All Customers deferred accounts in combination. Moreover, they state that PSNC's July 2017 Deferred Gas Cost Account Report filed in Docket No. G-5, Sub 574 on August 22, 2017, reflects a Sales Customers Deferred Account credit balance of $5,740,184, which is a decrease of $281,311 from the credit balance at the end of the review period. They note that the combined balance has gone from a credit balance of $13,471,026 at the end of March 2017 to a credit balance of $4,220,554 at the end of July 2017, which is a decrease in the amount owed to customers of $9,250,482. PSNC and the Public Staff further state that when the balance in the Hedging Deferred Account is included, the combined balance has gone from a credit balance of $14,027,967 at the end of March 2017 to a credit balance of $4,424,509 at the end of July 2017, which is a decrease of $9,603,458.

Further, PSNC and the Public Staff contend that based on the seasonality of the balance in the All Customers Deferred Account, it is likely that the combined balance as of November 1, 2017, the date on which they presumed that any decrements authorized in this proceeding would take effect, will be a debit balance. They state that this was the case subsequent to PSNC's 2016 ARGC in Docket No. G-5, Sub 568, and that not only was the balance in the All Customers Deferred Account at the end of October 2016 a debit balance of $11.2 million as noted previously, the combined balance in PSNC's deferred gas cost accounts was a debit balance of $3.1 million.

The Commission agrees with PSNC and the Public Staff that the Commission has the discretion under G.S. 62-133.4 to decide not to require a rate decrement or permit a rate increment. This discretion is grounded in the overriding principle that the Commission shall fix "just and reasonable rates." G.S. 62-130(a). In addition, the purchased gas adjustment (PGA) provisions of G.S. 62-133.4(b) are an integral part of the Commission's overall authority to set the guidelines for LDCs to recover their gas costs. The PGA provisions give the Commission unbridled discretion to immediately adjust an LDC's gas costs, without a hearing, based on a change in the LDC's Benchmark Commodity Cost of Gas.

One of the guiding principles of statutory interpretation is to interpret and apply related statutes, rules and regulations in a manner such that they are consistent with one another, or <u>in pari materia</u>, and to give full effect to each provision. <u>Brisson v. Santoriello, 351 N.C. 589, 595, 528 S.E.2d 568, 573 (2000)</u>. Although the word "shall" typically indicates a mandatory directive, rather than discretionary authority, the legislature's use of the word "shall" in G.S. 62-133.4(c) must be read in pari materia with the closely related provisions of G.S. 62-130(a) and G.S. 62-133.4(b). When so read, this comprehensive view demonstrates that it was not the legislature's intent to prescribe that the Commission absolutely order a rate decrement or increment in every ARGC. Instead, this combined consideration of the statutes supports the Commission's exercise of some discretion in determining whether to require a rate decrement or increment in an ARGC.

In addition, as a general rule unnecessary changes in rates detract from the Commission's goal of fixing just and reasonable rates. Such rate changes are not beneficial to either the ratepayers or the utility. Ratepayers can be confused and frustrated to receive a rate decrease one month, then a rate increase two or three months later. For the utility, frequent rate changes mean increased costs of printing and mailing customer notices and increased costs of reprogramming billing systems to reflect the rate changes. Of course, these utility costs are then passed on to the ratepayers. As a result, where it is reasonably apparent that a cost of gas rate decrement placed into effect in one month would begin contributing to the utility's underrecovery of costs of gas two or three months later, necessitating a rate increment, the Commission believes that it has the discretion under G.S. 62-133.4 to decide not to implement a rate decrement. Similarly, under the reverse circumstances, where it is reasonably apparent that a rate increment would be obviated by an overrecovery of gas costs two or three months later, necessitating a rate decrement, the Commission believes that it has the discretion to decide not to permit the utility to implement a rate increment.

From the time an LDC files its testimony in its Annual Review of Gas Cost (ARGC) until the Commission issues its order in an ARGC, a significant amount of time passes. Pursuant to Commission Rule R1-17(k)(6), PSNC filed the required information in this docket on June 1, 2017 for a test year ending March 31, 2017. The Commission's June 6, 2017 Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice set the matter for hearing on August 8, 2017. At the hearing, the parties agreed to file briefs and proposed orders in thirty days. The JPO was filed by the parties on September 8, 2017, more than five months after the end of the review period. Over that time, balances in the deferred accounts continued to change. A credit balance reported at the end of a test period in a given deferred account may already have been reduced by the time an order is issued. Even if the credit balance has not been completely reduced, the situation may allow the parties to put credible testimony in the record to the effect that the balance will be eliminated in the near future. Under such circumstances, ordering a bill credit of a temporary decrement to reduce an outdated balance would be an unnecessary rate change.

While unnecessary rate changes are undesirable, the Commission recognizes that, in times of unstable markets, it may be necessary and appropriate to implement rate changes in order to convey market pricing signals to the ratepayers. Furthermore, both PSNC's Rider C (Customer Usage Tracker) and Rider E (Integrity Management Tracker) mandate rate adjustments twice a year. Rider E calls for adjustments to be put into rates on March 1 and September 1, and Rider C calls for adjustments to be put into rates on April 1 and October 1. The Commission has seen various other rate changes put into effect at the time of these Rider adjustments. For example, in Docket No. G-5, Sub 547, PSNC proposed to make three different changes to rates: (1) to remove old increments and implement new increments under its Rider C , (2) to raise its Benchmark Commodity Gas Cost under its Rider D – Purchased Gas Adjustment mechanism, and (3) to eliminate the existing temporary increments that were placed in effect as a result of its ARGC.

The Commission does not agree with PSNC and the Public Staff that when determining whether to order a rate decrement or increment it is reasonable to consider the balances in the Sales Customers and All Customers deferred accounts as one balance. Unlike PSNC and the Public Staff, the Commission does not read the phrase "compare the utility's prudently incurred costs with costs recovered from all the utility's customers" in G.S. 62-133.4(c) to mandate combining the Sales Customers and All Customers deferred account balances, or to mandate any other methodology to be used in the Commission's analysis of whether to order a rate decrement or increment. Rather, the intent of this phrase is to describe the method by which the Commission is to evaluate the LDC's gas costs to determine whether the total amount of the LDC's gas costs was prudently incurred, and to determine whether the LDC should be allowed to recover that same amount from its customers. In essence, the sentence states a formula for the Commission to use in determining whether an LDC has been overpaid or underpaid for its gas costs during the review period. As such, it in no way addresses what the Commission should do if it determines that there was an over-recovery or under-recovery. That circumstance is addressed in the next sentence of the statute.

A credit balance owed to Sales Customers is owed to a different set of customers than a credit balance owed to All Customers ratepayers. Likewise, a debit balance owed by Sales Customers is owed by a different set of customers than a debit balance owed by All Customers ratepayers. Based on the position of PSNC and the Public Staff, if PSNC owed Customer A refund of $100 due to an overrecovery from Customer A, but PSNC was owed $100 by Customer B due to an underrecovery from Customer B, then PSNC would be justified in not paying Customer A until it received its money from Customer B. The Commission concludes that such a result is not intended by G.S. 62-133.4(c). If PSNC has a substantial credit balance in the All Customers account, and it is not reasonably apparent that the credit balance will correct itself within the next few months, then the Commission should exercise its discretion to require PSNC to implement a rate decrement for those customers receiving service under the All Customers account, irrespective of whether there is a credit or debit balance in PSNC's Sales Customers account. Furthermore, the Commission notes that different factors give rise to the imbalances in the different deferred accounts. The All Customers account balance is largely driven by seasonal fluctuations in the collection of fixed costs, net of the customers' share of margins from Secondary Market Transactions. The Sales Customers account balance is largely driven by the differences between the market price of natural gas and the Benchmark Commodity Cost of Gas embedded in rates, and by fluctuations in demand due to weather. In summary, the Sales Customers account and the All Customers account should be viewed as independent of one another in the Commission's analysis of whether to require a rate increment or rate decrement.

In the JPO, the parties referenced PSNC's July 2017 Deferred Gas Cost Account Report filed in Docket No. G-5, Sub 574. Since then, two more monthly reports have been filed. The July balance in the All Customers had already changed to a debit balance. By the report for the period ending September 30, 2017, the debit balance had grown to $6,586,245, further demonstrating the seasonality of the All Customers Deferred Account and making clear that no decrement is needed.

The JPO stated that the July Sales Customer Deferred Account had shown a debit balance that was $281,311 lower than at the end of the review period. By the September report in Docket No. G-5, Sub 574, that trend had reversed and the credit balance was $6,842,094, an increase of $840,599 owed to customers. However, the Hedging Deferred Account, which had shown a credit balance of $556,941 at the end of the March 31, 2017 review period (before being rolled into the

Sales Customers Deferred Account in this docket), had changed to a debit balance of $475,316, a difference of $1,032,257 to be collected from sales customers. Combining those two accounts at the end of September would have left a credit balance of $6,366,779, down from a combined balance of $6,578,436 at the end of the review period. The decrease in the combined outstanding credit balance in the six months through September was only $211,657.

On October 17, 2017, in Docket No. G-5, Sub 582 (Sub 582), PSNC filed an Application for Adjustment of Rates and Charges pursuant to G.S. 62-133.4 to reduce its commodity benchmark from the current $3.00 per dekatherm to $2.75 per dekatherm for service rendered on and after November 1, 2017, "based upon current market conditions and indicators." That application was approved by the Commission on October 30, 2017. The Commission believes based on past experience that deferred account balances are a factor considered by PSNC in proposing changes to commodity benchmarks. Furthermore, PSNC reports sales volumes to the Commission on a monthly basis in Docket No. G-100, Sub 24A. The report in that docket for November 2016 shows that, in the previous year, PSNC sold 42,061,093 dekatherms of gas. Using that as an estimate, a $0.25 per dekatherm reduction in the commodity benchmark, all other factors remaining constant, should yield approximately $10.5 million less charged to sales customers. The Commission concludes that the Sub 582 reduction in sales rates is adequate to reduce the credit balance in the Sales Customers Deferred Account, such that a separate decrement in this docket could lead to an under-collection of costs which could then result in an unnecessary rate increase. The Commission therefore concludes that no further decrement is needed in this docket.

The Commission expects PSNC to continue to monitor market conditions and the Sales Customer Deferred Account balances and, if necessary, to file a PGA to make an appropriate adjustment to rates. Furthermore, the Commission notes that PSNC will be filing a rate adjustment under its Rider E to be effective March 1. The Commission will require PSNC to discuss the status of the Sales Customer Deferred Account at the same time and, if necessary, file a PGA adjustment to become effective on March 1, concurrent with its Rider E adjustment.

Based on the facts in the present docket, and the record as a whole, the Commission finds and concludes that it is appropriate not to require PSNC to implement temporary rate decrements in the instant docket at this time. However, the Commission finds PSNC's management of the credit balances in the Sales Customer Deferred Account during the review period for this docket to be less than satisfactory. As a result, the Commission emphasizes that PSNC should fully utilize that portion of G.S. 62-133.4(b) that allows each LDC to "apply for permission to change its rates to track changes in the cost of natural gas supply and transportation," and allows the Commission, without a hearing, to issue "an order allowing such rate changes to become effective simultaneously with the effective date of the change in the cost of natural gas or at any other time ordered by the Commission." The Commission expects PSNC to make such filings, so that PSNC's Sales Customer Deferred Account will be managed using the purchase gas adjustment to keep its average balance close to zero.

IT IS, THEREFORE, ORDERED as follows:

1. That PSNC's accounting for gas costs for the 12-month period ended March 31, 2017, is approved.

2. That the gas costs incurred by PSNC during the 12-month period ended March 31, 2017, were reasonably and prudently incurred, and PSNC is hereby authorized to recover 100% of these gas costs as provided herein.

3. That, as proposed by PSNC and agreed to by the Public Staff in the instant docket, PSNC shall not implement any temporary rate changes effective for service rendered on and after December 1, 2017.

4. That on or before February 15, 2018, at the time of PSNC's filing required pursuant to Section IV(a) of PSNC's Rider E, PSNC shall provide the Commission with a discussion of the status of the balance in its Sales Customer Deferred Account and any action it proposes to take with regard to that account.

ISSUED BY ORDER OF THE COMMISSION
This the 15th day of December, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. G-41, SUB 50

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Toccoa Natural Gas for	)	
Annual Review of Gas Costs Pursuant to	)	ORDER ON ANNUAL
G.S. 62-133.4(c) and Commission	)	REVIEW OF GAS COSTS
Rule R1-17(k)(6)	)	

HEARD: Wednesday, November 1, 2017, at 10:00 a.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Jerry C. Dockham, Presiding, and Commissioner James G. Patterson

APPEARANCES:

For Toccoa Natural Gas:

Karen M. Kemerait, Smith Moore Leatherwood, LLP, 434 Fayetteville Street, Suite 2800, Raleigh, North Carolina 27601

NATURAL GAS – ADJUSTMENTS OF RATES/CHARGES

For the Using and Consuming Public:

Elizabeth D. Culpepper, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On September 1, 2017, Toccoa Natural Gas (Toccoa or Company), filed the direct testimony and exhibits of Rai Trippe, Member Support Senior Business Analyst for the Municipal Gas Authority of Georgia (Gas Authority), and Harry F. Scott, Jr., Utilities Director for the City of Toccoa, Georgia, in connection with the annual review of Toccoa's gas costs pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), for the 12-month period ended June 30, 2017.

On September 8, 2017, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. This Order established a hearing date of November 1, 2017, set prefiled testimony dates, and required Toccoa to give at least 30 days prior notice to its customers of the hearing on this matter.

On October 5, 2017, Toccoa filed its Affidavit of Publication.

On October 12, 2017, Toccoa filed the revised schedules and exhibit of Company witness Trippe.

On October 16, 2017, the Public Staff filed the Joint Testimony of Jan A. Larsen, Director, Natural Gas Division; Iris Morgan, Staff Accountant, Accounting Division; and Julie G. Perry, Accounting Manager, Natural Gas & Transportation Section, Accounting Division (Public Staff Panel).

On October 17, 2017, Toccoa and the Public Staff filed a Joint Motion to Excuse Appearance of Witnesses and Accept Testimony, which was granted by the Commission on October 20, 2017.

On November 1, 2017, the matter came on for hearing as scheduled, and all prefiled testimony and exhibits were admitted into evidence. No public witnesses appeared at the hearing.

Commissioner ToNola D. Brown-Bland was assigned as a member of the panel in this docket. Commissioner Brown-Bland was unable to be present at the hearing on November 1, 2017. However, because there were no witnesses present at the hearing and all pre-filed testimony was stipulated into the record, no testimony or cross-examination was presented at the hearing. Therefore, the parties stipulated that Commissioner Brown-Bland can participate as a member of the panel in this docket.

In compliance with the requirements of Chapter 138A of the North Carolina Government Ethics Act, each member of the Commission panel has made a due and diligent effort to determine whether he or she has a conflict of interest in the matter presented in this docket, and each member of the panel has determined that he or she does not have any such conflict.

On November 30, 2017, Toccoa and the Public Staff filed a Joint Proposed Order.

On December 15, 2017, Toccoa and the Public Staff (Movants) filed a joint motion requesting that the Commission allow the Movants to supplement the record by accepting two revised pages of the Public Staff's testimony, and accepting one revised page of the Joint Proposed Order filed by the Movants in order to correct minor errors in the Public Staff's original testimony and in the Joint Proposed Order.

On December 18, 2017, the Commission issued an Order Granting Motion to Supplement Record that accepted the Movants' filings supplementing the Public Staff's testimony and the Joint Proposed Order.

Based on the testimony, exhibits, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. Toccoa, a division of the City of Toccoa, Georgia, is a public utility as defined by G.S. 62-3(23) and as such is subject to the jurisdiction of the Commission.

2. Toccoa is primarily engaged in the business of purchasing, transporting, distributing, and selling natural gas to approximately 6,567 retail customers of which approximately 726 are in North Carolina.

3. The Company has filed with the Commission and submitted to the Public Staff all information required by G.S. 62-133.4(c) for an annual review of gas costs and Commission Rule R1-17(k) for an annual review of gas costs and has complied with the procedural requirements of such statute and rule.

4. The review period in this proceeding is 12-months ended June 30, 2017.

5. During the review period, Toccoa incurred total North Carolina gas costs of $380,846[1], which was comprised of demand and storage costs of $94,977 and commodity costs of $286,297, less other gas costs of $427.

6. On June 30, 2017, Toccoa had a credit balance of $37,260, owed by Toccoa to customers, in its Deferred Gas Cost Account.

7. On October 1, 2016, Toccoa began calculating interest on its deferred account using the net-of-tax overall rate of return approved by the Commission in its Order Granting Certificate of Public Convenience and Necessity to the City of Toccoa and the Municipal Gas Authority of Georgia issued December 8, 1998, in Docket No. G-41, Sub 0, adjusted for any known corporate income tax rate changes, as the applicable interest rate on all amounts overcollected or undercollected from customers, as reflected in its Deferred Gas Cost Account.

8. Toccoa properly accounted for its gas costs during the review period.

[1] Due to rounding of the numbers on Revised Trippe Schedule 2, the total North Carolina gas costs totals $380,846 instead of $380,847.

9. Toccoa's hedging activities during the review period were reasonable and prudent.

10. Toccoa has transportation and storage contracts with interstate pipelines that provide for the transportation of gas to Toccoa's system and an "all requirements" gas supply contract with the Gas Authority.

11. Toccoa released unutilized capacity during the review period to mitigate the cost of demand capacity, and all margins earned on secondary market transactions reduced the cost of gas and were flowed through to ratepayers.

12. Toccoa has adopted a "portfolio approach" gas purchasing policy that consists of four main components: long-term firm supply arrangements, short-term spot market purchases, seasonal peaking, and contract storage services.

13. Toccoa's gas purchasing policy and practices during the review period were prudent, and its gas costs during the review period were prudently incurred.

14. Toccoa should be permitted to recover 100% of its prudently incurred gas costs.

15. The Company should implement a temporary rate decrement of $0.4397 per dekatherm (dt) and remove the existing decrement of $1.3172 per dt, as recommended by the Public Staff and agreed to by Toccoa.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

The evidence supporting these findings is contained in the official files and records of the Commission and the testimony and revised schedules and exhibit of Toccoa witness Trippe and the testimony of Toccoa witness Scott. These findings are essentially informational, procedural, or jurisdictional in nature and are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

The evidence supporting these findings of fact is contained in the testimony and revised schedules and exhibit of Toccoa witness Trippe and the testimony of the Public Staff Panel. These findings are made pursuant to G.S. 62-133.4(c), and Commission Rule R1-17(k)(6).

G.S. 62-133.4(c) requires that each natural gas utility submit to the Commission information and data for a historical 12-month review period concerning its actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(a) establishes June 30, 2017, as the end date of the annual review period for the Company in this proceeding. Commission Rule R1-17(k)(6)(c) requires that Toccoa file weather-normalized sales volumes, work papers, and direct testimony and exhibits supporting the information.

Toccoa witness Trippe testified that he was not aware of any outstanding issues regarding the reporting requirements of Commission Rule R1-17(k)(5)(c), which requires the Company to file a complete monthly accounting of computations under the provisions of the Rule for gas costs and deferred account activity. The Public Staff Panel confirmed that it had reviewed the filings and monthly reports filed by Toccoa.

Based upon the foregoing, the Commission concludes that Toccoa has complied with all procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the 12-month review period ended June 30, 2017.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-8

The evidence supporting these findings of fact is contained in the testimony and revised schedules and exhibit of Toccoa witness Trippe and the testimony of the Public Staff Panel.

Company witness Trippe testified that Toccoa incurred total North Carolina gas costs of $380,846[1] during the review period, which was comprised of demand and storage costs of $94,977, commodity costs of $286,297, and other gas costs of ($427). The Public Staff Panel stated that every month the Public Staff reviews the Deferred Gas Cost Account reports filed by Toccoa for accuracy and reasonableness, and performs audit procedures on the calculations. The Public Staff Panel also provided testimony that Toccoa had properly accounted for its gas costs during the review period.

The Public Staff Panel testified that, as of June 30, 2017, the balance in Toccoa's Deferred Gas Cost Account was a credit balance of $37,260, owed by Toccoa to customers. The Public Staff Panel also testified that Toccoa's Deferred Gas Cost Account consisted of the following activity: Commodity True-up of $5,029, Demand True-up Credit of $39,201, Firm Hedges Credit of $427, and Increment activity of $109,884 and Interest Credit of $2,806.

The Public Staff Panel further testified that due to the recurring credit balances in the Company's Deferred Gas Cost Account, and in accordance with G.S. 62-130(e), on October 1, 2016, Toccoa began calculating interest on its deferred account. The Public Staff Panel further explained that Toccoa is using the net-of-tax overall rate of return approved by the Commission in its Order Granting Certificate of Public Convenience and Necessity to the City of Toccoa and the Municipal Gas Authority of Georgia issued December 8, 1998, in Docket No. G-41, Sub 0, adjusted for any known corporate income tax rate changes, as the applicable interest rate on all amounts overcollected or undercollected from customers as reflected in its Deferred Gas Cost Account. All other methods and procedures used by the Company for the accrual of interest on the Deferred Gas Cost Account are consistent with the other North Carolina local distribution companies (LDCs).

Based on the foregoing, the monthly filings by Toccoa pursuant to Commission Rule R1-17(k)(5)(c), and the findings and conclusions set forth above, the Commission concludes that Toccoa has properly accounted for its gas costs incurred during the review period and that Toccoa's Deferred Gas Cost Account balance reflected in the Company's schedules and exhibits is

[1] Due to rounding of the numbers on Revised Trippe Schedule 2, the total North Carolina gas costs totals $380,846 instead of $380,847.

correct. The Commission further concludes that it is appropriate for Toccoa to begin calculating interest on the deferred account using the net-of-tax overall rate of return approved by the Commission in its Order Granting Certificate of Public Convenience and Necessity to the City of Toccoa and the Municipal Gas Authority of Georgia issued in Docket No. G-41, Sub 0.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is contained in the testimony and revised schedules and exhibit of Toccoa witness Trippe and the testimony of the Public Staff Panel.

Company witness Trippe testified that Toccoa participates in the Gas Authority's WinterHedge Program under the Authority's Option 2. Witness Trippe stated that the Gas Authority's objective in hedging prices is to achieve price stability at a reasonable level for its members' retail customers. Company witness Trippe also testified that although hedging helps manage volatility in the wholesale cost of gas, it can create its own challenges. He explained that some customers have unrealistic expectations of the benefits of hedging, because a common benchmark for evaluating hedged prices is the actual spot market price. Witness Trippe further testified that this can be an unfair measure because it is only available after the fact, and assumes that the goal of hedging is "to beat the market." He also testified that the principal goal of hedging is to achieve price stability, at a reasonable level, for the consuming public.

The Public Staff Panel testified that when a Gas Authority member enters into hedging arrangements with the Gas Authority, the member specifies the targeted level of volumes to hedge and that these arrangements typically span two to three years. The Public Staff Panel further testified that the Gas Authority typically uses fixed price swaps, basis swaps, and three-way options as financial instruments in its hedging program.

Further, the Public Staff Panel stated that during the current review period, Toccoa's hedging program resulted in a $427 credit to its gas supply cost for North Carolina customers.

The Public Staff Panel testified that Toccoa had reviewed its Winter Hedge Program participation and elected to reduce its winter hedge volumes to approximately 23% of all firm North Carolina gas sales for November 2016 through March 2018. The Public Staff Panel further stated that at the time this decision was made, Toccoa chose to adopt more conservative hedge volumes for its participation in the Winter Hedge Program because market and futures pricing was significantly lower than it had been at the time the previous Winter Hedge Program volumes were put in place. The Public Staff Panel also explained that Toccoa elected the maximum hedging program term offered by the Gas Authority of two years beginning November 1, 2016.

Further, the Public Staff Panel stated that based on what was reasonably known or should have been known by Toccoa at the time the Company made its hedging decisions affecting the review period, as opposed to the outcome of those decisions, the Company's hedging decisions were prudent.

Based on the testimony presented by the Company and the Public Staff, the Commission concludes that the Company's hedging activities during the review period were reasonable and prudent.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-14

The evidence for these findings of fact is contained in the testimony and revised schedule and exhibit of Toccoa witness Trippe and the testimony of the Public Staff Panel.

Company witness Trippe testified that Toccoa is a charter member of the Gas Authority, the largest non-profit joint action natural gas agency in the nation. Company witness Trippe also testified that, as a member of the Gas Authority, Toccoa receives all of its gas supply at very competitive rates. He further explained that the Gas Authority uses a portfolio approach to supply its 79 member cities' needs, relying on a combination of long-term firm supply arrangements, short-term spot market purchases, seasonal peaking, and contract storage services. He also testified that Toccoa is assured adequate, dependable, and economical gas supplies through the Gas Authority's efforts.

The Public Staff Panel testified that Toccoa has contracts for pipeline capacity and storage service from Transcontinental Gas Pipe Line Company, LLC, for a storage service contract with Pine Needle LNG Company, LLC, and for a gas supply contract with the Gas Authority. The Public Staff Panel further explained that as the all requirements supplier for Toccoa, the Gas Authority manages all of Toccoa's pipeline, storage service, and gas supply contracts. Based upon the Public Staff Panel's investigation and review of the data filed in this docket, the Public Staff concluded that Toccoa's gas costs during the review period were prudently incurred.

Company witness Trippe testified that the Gas Authority, on behalf of Toccoa, was able to release a portion of Toccoa's unutilized capacity each month of the test period to mitigate the cost of extra demand capacity, generating a savings during the period of July 2016 - June 2017 that totaled $23,029. The Public Staff Panel testified that Toccoa's policy has always been to flow through 100% of its capacity release credits to ratepayers.

Based on the foregoing, the Commission concludes that the Company's gas purchasing policies and practices during the review period were reasonable and prudent, that its gas costs during the review period were prudently incurred, and that the Company should be permitted to recover 100% of its prudently incurred gas costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this finding of fact is contained in the testimony and revised schedule and exhibit of Toccoa witness Trippe and the testimony of the Public Staff Panel.

The Public Staff Panel testified that the balance in Toccoa's Deferred Gas Cost Account at June 30, 2017, was a $37,260 credit balance, owed to customers. The Public Staff Panel stated, in general, temporary increments or decrements for an LDC are calculated using the volumes from the LDC's last general rate case. As Toccoa has never had a general rate case, the Public Staff has previously recommended, and the Commission has previously approved, using the review period, North Carolina firm sales volumes instead in this calculation. For the current review period ended June 30, 2017, the North Carolina firm sales volumes are 84,749 dts. Therefore, the Public Staff Panel proposed a temporary rate decrement of $0.4397 per dt calculated using the Deferred Gas Cost Account credit balance of $37,260 divided by 84,749 dts. Furthermore, the Public Staff Panel recommended that this temporary rate decrement be approved for all North Carolina firm sales customers effective the first day of the month following the date of the Commission's order in this proceeding, and that the current decrement of $1.3172 per dt that was placed into rates effective August 1, 2016, in Docket No. G-41, Sub 46, be removed. Finally, the Public Staff Panel stated that it understood that Toccoa did not oppose this recommendation.

Based on the foregoing, the Commission concludes that the temporary rate decrement recommended by the Public Staff Panel and not opposed by Toccoa is appropriate and should be implemented.

IT IS, THEREFORE, ORDERED as follows:

1. That Toccoa's accounting for gas costs for the 12-month period ended June 30, 2017, is approved;

2. That the gas costs incurred by Toccoa during the 12-month period ended June 30, 2017, including the company's hedging costs, were reasonably and prudently incurred, and that Toccoa is authorized to recover 100% of its gas costs incurred during the period of review;

3. That Toccoa shall use the net-of-tax overall rate of return approved by the Commission in its Order Granting Certificate of Public Convenience and Necessity to the City of Toccoa and the Municipal Gas Authority of Georgia issued December 8, 1998, in Docket No. G-41, Sub 0, adjusted for any known corporate income tax rate changes, as the applicable interest rate on all amounts overcollected or undercollected from customers as reflected in its Deferred Gas Cost Account;

4. That Toccoa shall remove the existing temporary decrement of $1.3172 per dt, that was approved in Docket No. G-41, Sub 46, and implement the rate decrement of $0.4397 per dt as found appropriate herein, effective for service rendered on and after the first day of the month following the date of this Order;

5. That Toccoa shall give notice to its customers of the rate changes allowed in this Order; and

6. That Toccoa shall file revised tariffs as soon as practicable to reflect the implementation of the rate changes ordered herein.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of December, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. G-40, SUB 136

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Joint Application of Frontier Natural Gas Company and FR Bison Holdings, Inc., for Approval of Acquisition of Stock of Gas Natural, Inc.	)	ORDER APPROVING MERGER SUBJECT TO REGULATORY CONDITIONS

HEARD: May 8, 2017, 2:00 p.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Chairman Edward S. Finley, Jr.; and Commissioners Bryan E. Beatty, Don M. Bailey, Jerry C. Dockham, James G. Patterson, and Lyons Gray

APPEARANCES:

For Frontier Natural Gas Company and Gas Natural, Inc.:

M. Gray Styers, Jr., Smith Moore Leatherwood, 434 Fayetteville Street, Suite 2800, Raleigh, North Carolina 27601

For FR Bison Holdings, Inc., First Reserve Corporation, and BlackRock, Inc.:

James H. Jeffries IV, Moore & Van Allen PLLC, 100 N. Tryon Street, Suite 4700, Charlotte, North Carolina 28202

For the Using and Consuming Public:

Elizabeth D. Culpepper, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On November 23, 2016, Frontier Natural Gas Company (Frontier) and FR Bison Holdings, Inc. (FR Bison) (collectively, Initial Applicants), filed an application pursuant to G.S. 62-111(a) for: (1) authorization for First Reserve Corporation to acquire one hundred percent (100%) of the stock of Gas Natural, Inc. (GNI), the parent company of Frontier, pursuant to an Agreement and Plan of Merger among Gas Natural, Inc., FR Bison Holdings, Inc., and FR Bison Merger Sub, Inc. (Merger Agreement), which was filed as Exhibit C to the Application, and (2) authorization and/or waiver as necessary and appropriate to effect the proposed transaction. The Application also included a cost-benefit analysis, and charts showing both GNI's current corporate organization and the new corporate organization following the proposed transaction. In support of the Application, the Initial Applicants also filed the testimony of James E. Sprague, Chief Financial Officer of GNI; Fred A. Steele, President/General Manager of Frontier; Kevin J. Degenstein, Chief Operating Officer and Chief Compliance Officer of GNI; and Ryan Shockley, Managing Director of First Reserve Corporation.

In the Application, the Initial Applicants requested a waiver of the requirement in the Commission's Order Requiring Filing of Analyses, issued November 2, 2000, in Docket No. M-100, Sub 129 (M-100, Sub 129 Order), to provide a market power analysis in conjunction with the proposed merger. The Initial Applicants stated that, given the relatively small size of Frontier's North Carolina operations and the lack of any other First Reserve Corporation company operations served by or in proximity to Frontier's service territory, there is no possibility that the merger will enhance or increase either Frontier's or First Reserve Corporation's market power in any relevant retail or wholesale market.

On January 30, 2017, the Commission issued its Order Scheduling Hearing, Establishing Procedural Deadlines and Requiring Public Notice (Scheduling Order). The Scheduling Order, among other things, established a hearing date of May 8, 2017, set prefiled testimony dates, and required the Applicants to give notice to Frontier's customers of the hearing on this matter.

On January 31, 2017, the Public Staff filed its recommendation that the Commission issue an order granting the Applicants' request for waiver of the requirement to file a market power analysis.

On January 31, 2017, the Initial Applicants filed the amended direct testimony of Kevin J. Degenstein. This testimony was further amended on February 2, 2017, in order to reflect the accurate date of witness Degenstein's amended direct testimony.

On February 6, 2017, the Commission issued an Order Granting Waiver of Market Power Analyses Requirement.

On February 14, 2017, the Initial Applicants filed an amended application and the revised direct testimony of Applicants' witness Shockley. In the amended application (amended Application or Application), the reference to First Reserve Corporation was revised to refer to FR Bison, and the name First Reserve was used to reference First Reserve Energy Infrastructure GP II, Limited. The references to First Reserve throughout the remainder of this Order are to First Reserve Energy Infrastructure GP II, Limited.

Initial Applicants stated that the amended Application was the result of two events that first became known to First Reserve after the filing of the original Application. According to Initial Applicants, the first of these events was the realization that GNI could become a U.S. Real Property Holding Company for federal income tax purposes, which could potentially violate covenants in First Reserve's agreements with investors in its infrastructure funds. In order to eliminate this possibility, First Reserve changed the identity of the immediate parent of FR Bison from First Reserve Energy Infrastructure Fund II, L.P., to another First Reserve affiliate, FREIF II Echo AIV, L.P. (FREIF).

According to Initial Applicants, the second event prompting the amended Application and revised testimony was an agreement between First Reserve Partners L.P., First Reserve Management, L.P. (collectively, FR Sellers) and BlackRock, Inc. (BlackRock) pursuant to which the FR Sellers agreed to sell their energy infrastructure business to BlackRock (BlackRock Transaction). The Initial Applicants stated that the BlackRock Transaction, upon closing, would result in a change in the ultimate parent of GNI from First Reserve to BlackRock, but would not otherwise impact GNI, Frontier, Frontier's customers, or the merger. The amended Application and the amended testimony of Ryan Shockley, reflecting the changes made as a result of these two events, requested approval of the merger, with the additional component of the BlackRock Transaction.

On May 2, 2017, the Public Staff filed the joint testimony of Public Staff witnesses Julie G. Perry, Manager, Accounting Division, Jan A. Larsen, Director, Natural Gas Division, and Calvin C. Craig, III, Financial Analyst, Economic Research Division (Public Staff testimony). Attached to the Public Staff testimony was a set of proposed regulatory conditions that had been agreed to by the Public Staff, the Applicants, and certain other entities (Regulatory Conditions). Subject to the agreed upon Regulatory Conditions, the Public Staff testimony supported approval of the Merger as consistent with the Commission's requirements under G.S. 62-111(a).

On May 4, 2017, the Initial Applicants filed the Rebuttal Testimony of Ryan Shockley and the Joint Rebuttal Testimony of Fred A. Steele, Kevin J. Degenstein, and James E. Sprague. This testimony acknowledged the Initial Applicants' support of, and agreement with, the Regulatory Conditions and urged approval of the proposed merger as justified by the public convenience and necessity.

Also on May 4, 2017, First Reserve and First Reserve Energy Infrastructure Fund II, L.P filed a statement with the Commission consenting to the Regulatory Conditions proposed by the Public Staff and agreed to by Frontier and FR Bison. Further, they stated that their consent to the Regulatory Conditions "does not constitute a general consent to expansion of the North Carolina Utilities Commission's jurisdiction over [them] beyond that established by Chapter 62 of the North Carolina General Statutes.

On May 8, 2017, BlackRock filed a confidential statement with the Commission.

No other party intervened or filed testimony in this proceeding.

The matter came on for hearing before the Commission on May 8, 2017, as scheduled. No public witnesses testified regarding this matter. The prefiled testimony and exhibits of the Initial Applicants and the Public Staff were admitted into the record and received into evidence without objection. In addition, the Amended Application and exhibits thereto were entered into the record without objection. The Initial Applicants also requested that the Commission take judicial notice of letters filed by First Reserve and BlackRock in this proceeding on May 4 and May 8, 2017, respectively.

On June 8, 2017, the Initial Applicants filed notice with the Commission of the closing of the BlackRock Transaction.

On June 14, 2017, the Public Staff filed a late-filed exhibit showing an illustration of the methodology for calculating the rolling 12-month earned return on average rate base referenced in Regulatory Condition 10.

On June 15, 2017, the Initial Applicants and Public Staff filed a Joint Proposed Order and a Supplemental Brief on Specified Issues.

On June 21, 2017, Frontier filed a copy of the Finding and Order issued by the Public Utilities Commission of Ohio on that same date.

On June 26, 2017, Frontier filed a copy of the Order Approving Stipulation issued by the Maine Public Utilities Commission on June 23, 2017.

On July 17, 2017, the Commission issued an Order Joining Necessary Party and Requiring Additional Verified Information (BlackRock Order). The BlackRock Order, among other things, joined BlackRock as a necessary party and required BlackRock to file a verified statement or affidavit or testimony specifically addressing the following four items: (1) BlackRock's plans for appointing members to serve on GNI's board of directors; (2) the process by which BlackRock will decide when to infuse capital into Frontier, how much capital to allocate to Frontier, and on what terms; (3) BlackRock's intent with regard to its length of ownership of GNI and Frontier; and (4) BlackRock's acceptance of the proposed Regulatory Conditions.

On July 20, 2017, BlackRock filed verified statements of Ryan Shockley and Anne Valentine Andrews. In addition, BlackRock's counsel, James H. Jeffries, IV, filed a Notice of Appearance. BlackRock, First Reserve, FR Bison and Frontier are collectively referred to as the Applicants.

Also on July 20, 2017, the Public Staff filed a letter stating its position with regard to BlackRock's filing.

On July 21, 2017, Frontier filed a copy of the Final Order of the Public Service Commission of Montana dated June 29, 2017, approving the merger.

Based on the testimony and exhibits presented at the hearing of this matter, the verified statements of the parties, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

I. <u>Jurisdiction and Procedure</u>

1. Frontier is a North Carolina corporation headquartered in Elkin, North Carolina, and is engaged in the business of transporting and selling natural gas as a local distribution company (LDC), pursuant to certificates of public convenience and necessity previously issued by the Commission for service to customers in Yadkin, Surry, Wilkes, Warren, Watauga and Ashe Counties.

2. Frontier is a public utility under the laws of the State of North Carolina and, as of October 31, 2016, provided natural gas redelivery or sales service to approximately 3,368 customers in the State of North Carolina.

3. GNI is a publicly traded corporation duly organized and existing under the laws of the State of Ohio. Frontier, as well as several other regulated natural gas utilities in other states, is owned by PHC Utilities, Inc., a wholly owned subsidiary of GNI.

4. FR Bison is a wholly owned subsidiary of FREIF, the general partner owner of which is First Reserve Energy Infrastructure GP II, L.P. (First Reserve LP). The general partner owner of First Reserve LP is First Reserve. FREIF and FR Bison are hereinafter collectively referred to as the First Reserve Entities.

5. First Reserve was a private equity firm focused on energy infrastructure investments and is now owned ultimately by BlackRock.

6. BlackRock is a publicly traded asset management firm with over $5 trillion dollars of assets under management. It serves clients in over 100 countries.

7. On June 2, 2017, the BlackRock Transaction closed and, as a result, BlackRock will become the ultimate parent of GNI and Frontier after the closing of the Merger.

8. The Applicants are lawfully and properly before this Commission pursuant to G.S. 62-111(a) with respect to the relief sought in the Amended Application and are in compliance with the requirements of the M-100, Sub 129 Order with respect to a cost-benefit analysis related to the proposed transaction, the requirement of a market power analysis having been waived by the Commission.

9. The Amended Application, testimony, exhibits, affidavits of publication, and public notices submitted by the Applicants are in compliance with the procedural requirements of the North Carolina General Statutes and the Rules and Regulations of the Commission.

II. Nature of Proposed Transaction

10. The Merger Agreement provides that, at closing, GNI will merge with FR Bison Merger Sub, Inc., with GNI being the surviving corporation. In conjunction with this combination, GNI shareholders will receive $13.10 a share, in cash, for each outstanding share of GNI common stock. Following the closing of the Merger, GNI will no longer be a publicly traded company, but will instead exist as a wholly-owned subsidiary of FR Bison.

11. Following the closing, GNI shall continue to operate Frontier and GNI's other subsidiary natural gas utilities and non-regulated entities.

12. Following the closing, GNI will maintain its current corporate structure.

III. Post-Closing Operations and Commitments

13. Following the closing, the management and operations of Frontier will not be modified, and Frontier will continue to be operated as a North Carolina public utility providing natural gas sales and redelivery service to the public in compliance with and subject to all existing obligations of Frontier under applicable statutes, rules and regulations, and prior Commission orders.

14. The Merger will not diminish the Commission's jurisdiction over Frontier, and the Commission will continue to exercise the oversight authority and all powers granted to it by Chapter 62 of the North Carolina General Statutes and the Commission's Rules and Regulations.

15. Following the closing, Frontier will continue to provide natural gas utility service to the public under its approved rates, terms, and conditions of service.

16. Any future proposed changes to the rates, terms, or conditions of service of Frontier will be subject to Commission review and approval.

17. The proposed Merger will not lead to the concentration or creation of additional market power by GNI, Frontier, the First Reserve Entities and their affiliates, or BlackRock, and will not result in an anti-competitive impact on markets subject to the Commission's jurisdiction.

18. The Regulatory Conditions agreed to by the First Reserve Entities, GNI, PHC Utilities, Inc., and Frontier, on the one hand, and the Public Staff, on the other, and acknowledged and consented to by First Reserve, First Reserve LP, and BlackRock (the current Parent Entities), will ensure that Frontier and GNI will continue to be operated in a manner consistent with the public interest following the close of the Merger.

IV. Benefits

19. Known and potential benefits of the Merger are both quantifiable and non-quantifiable in nature.

20. Known and potential quantifiable benefits of the Merger, agreed to by the Applicants and supported by the record, include:

(i) One-time bill credit to North Carolina customers totaling $100,000 to be completed no later than the last day of the first full calendar month following closing of the Merger;

(ii) Additional savings over time resulting from the transition of GNI from a public company to a privately held company;

(iii) Preservation of Frontier's existing rates and charges and a commitment to maintain Frontier's margin rates at existing levels through December 31, 2021; and

(iv) Elimination of any possible future proposed adjustment to Frontier's rate base to recapture (1) any past negative acquisition adjustments or asset impairment write downs from prior Frontier mergers, or (2) any portion of the acquisition premium resulting from this proceeding.

21. Known and potential non-quantifiable benefits of the Merger identified by the Applicants, and supported by the record, include:

(i) Retention of Frontier's employees, corporate presence, and business operations in North Carolina;

(ii) Enhanced access to capital, combined with North Carolina economic incentives should expand opportunities for growth within Frontier's existing service territory and for potential expansion of service in the future;

(iii) Enhanced access to capital to fund pipeline safety related investments required by federal or state regulations;

(iv) Continued transparency and monitoring of capital budgets, operational and financial condition, pipeline safety, accounting procedures, internal management restructuring, legal proceedings, and other service-related activities of Frontier;

(v) A commitment to maintain a minimum level of common equity capital for Frontier equal to or greater than forty-five percent (45%) of total adjusted capital;

(vi) A commitment to provide annual audited financial statements of GNI to the Commission and the Public Staff on an ongoing basis; and

(vii) Restriction on dividends paid by Frontier to the parent entities.

V. Mitigation of Potential Costs and Risks

22. The Merger may result in costs; however any known and potential costs of the Merger are eliminated or mitigated to the fullest extent reasonably possible by the commitments of the Applicants and by the agreed upon Regulatory Conditions.

23. The Amended Application and testimony of the Applicants waive any potential claim for recovery of the $14.1 million acquisition premium from Frontier's North Carolina ratepayers.

24. The Amended Application and testimony of the Applicants waive any potential claim for recovery of transaction fees associated with the Merger from Frontier customers.

25. The agreed upon Regulatory Conditions remove the impact of all direct and indirect Merger-related costs from Frontier's rates and charges.

26. The agreed upon Regulatory Conditions provide reasonable and adequate safeguards and continued oversight of Frontier by the Public Staff and the Commission consistent with the public interest.

VI. Public Convenience and Necessity

27. The proposed Merger, as described and conditioned by the Amended Application, the testimony of the witnesses, and the agreed upon Regulatory Conditions, is justified by the public convenience and necessity, serves the public interest, and should be approved.

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

The evidence supporting these findings of fact is set forth in the Amended Application, the Merger Agreement, the Cost-Benefit Analysis, the testimony of the Applicants' witnesses, the verified statements, and the Commission's records in this and other proceedings.

According to the Amended Application and Merger Agreement, as well as the testimony of Applicants' witnesses Shockley and Degenstein, FR Bison and GNI intend to engage in a transaction pursuant to which FR Bison will become the owner of GNI through the purchase of all the outstanding stock of GNI from GNI's existing shareholders. There is no dispute that such a transaction requires the approval of this Commission under G.S. 62-111(a) and the Amended Application seeks such approval.

In addition, the Commission's M-100, Sub 129 Order requires the Applicants to file both a market power analysis and a cost-benefit analysis in conjunction with an application for Commission approval of a proposed merger. The purpose of these required filings is to assist the Commission in making the public convenience and necessity determination required under G.S. 62-111(a).

Consistent with the requirements of the M-100, Sub 129 Order, the Application included, as Exhibit E, a Cost-Benefit Analysis that enumerated identified costs and benefits associated with the proposed Merger. The Application also requested a waiver of the market power study requirement in light of the absence of any affiliates' presence in or near the service territory in which Frontier operates. The Public Staff reviewed the Application and other information provided by the Initial Applicants, and performed research on the market power issue. After conducting that research, the Public Staff determined that it was reasonable for the market power analysis requirement to be waived in this proceeding and recommended that the Commission issue an order granting a waiver of the requirement to file a market power analysis and stating that the Application satisfies the requirements of the M-100, Sub 129 Order. In its Order Granting Waiver of Market Power Analyses Requirement, the Commission found good cause to grant the Initial Applicants' waiver request as to the filing of a market power analysis.

Finally, a review of the record in this proceeding indicates that the Initial Applicants have complied with all procedural and notice requirements established by the Commission in the Order Scheduling Hearing.

With respect to the BlackRock Transaction, the original request of the Applicants (as stated in the Amended Application and confirmed at the hearing of this matter) was that the Merger be approved regardless of the pendency of that transaction. This request raised some uncertainty over the sequence and timing of the Merger and the BlackRock Transaction, how the pendency of the BlackRock Transaction might impact required approvals by the Commission, and the efficacy of this approval in the event that the BlackRock Transaction closed. The record in this proceeding indicates that the BlackRock Transaction has closed and First Reserve is now owned and managed by BlackRock.[1]

As a result of the BlackRock Transaction closing, the Commission concluded that since BlackRock would obtain the ultimate ownership or control of Frontier, BlackRock is a necessary party to this proceeding. Pursuant to G.S. 62-111(a), the Commission must determine whether a change in ownership and control of a public utility subject to its regulation is justified by the public convenience and necessity. Therefore, the Commission sought in its BlackRock Order evidence on the record of BlackRock's plans with respect to GNI and Frontier. In the BlackRock Order, the Commission required competent evidence of record from BlackRock on the following matters: (1) BlackRock's plans for appointing members to serve on GNI's board of directors; (2) the process by which BlackRock will decide when to infuse capital into Frontier, how much capital to allocate to Frontier, and on what terms; (3) BlackRock's intent with regard to its length of ownership of GNI and Frontier; and (4) BlackRock's acceptance of the proposed Regulatory Conditions. Further, the BlackRock Order afforded the Public Staff an opportunity to respond to the BlackRock filing unless the parties determined that a joint filing or stipulation was in order, or the Public Staff made a filing stating that it did not plan to file any response. With regard to the ultimate control of Frontier and the corporate decision-making process, witness Shockley testified at the hearing on May 8, 2017, that First Reserve would allocate capital through FR Bison to GNI to Frontier. According to witness Shockley, the decision-making process would be for Frontier to make recommendations for capital deployment. Frontier's recommendations would be made to GNI, then GNI would make a recommendation to the First Reserve board of directors. The First Reserve board of directors would consider such recommendations on an annual basis, as part of its budgeting decisions. If there are special projects requiring funding, then First Reserve's board of directors could call a special meeting to address those capital needs. First Reserve would then "allocate capital through the corporate structure as appropriate to make sure it's spent as directed by Fred and Frontier." (T, at p. 145) In addition, witness Shockley testified that First Reserve had not decided who will be on the GNI board, but First Reserve will control the GNI board and have a majority of members on it.

With regard to First Reserve's long-term plans for owning the regulated utilities that are GNI subsidiaries, witness Shockley testified that GNI's operations, and particularly those in North Carolina, meet the dynamic of stability and long-term growth that First Reserve desires. In response to a Commission question about First Reserve's meaning of "long-term," witness Shockley testified that First Reserve has a 15-year fund, and he stated "[w]hen we talk about long term, we are really looking at, you know, 12- to 15-year periods. For good assets we're optimistic that we'll be able to find ways to hold them longer, whether that's through another fund or through an extension of the commitments from our limited partners for the right assets." (T, at pp. 163-164)

[1] On June 8, 2017, counsel for First Reserve and BlackRock filed in this docket a letter of notification of the closing of the acquisition of 100% of the equity interests of First Reserve Energy Infrastructure GP II Limited and First Reserve Advisors, L.L.C. and a 9.9% limited partnership and carried interest in First Reserve Energy Infrastructure GP II, L.P. by BlackRock, Inc.

On July 20, 2017, in his verified statement, witness Shockley stated that he is a Managing Director of First Reserve Advisors, L.L.C. (Advisor), an investment advisor subsidiary of BlackRock, and noted that prior to being employed by BlackRock he was a Managing Director of First Reserve Infrastructure GP II Limited, and a Managing Director of the Advisor. Witness Shockley further stated that in his former position he provided testimony in this docket regarding the intentions of First Reserve as the prospective ultimate parent of Frontier after the proposed Merger. In addition, he noted that the closing of the BlackRock Transaction resulted in BlackRock becoming the ultimate corporate parent of First Reserve, and the ultimate general partner of FREIF II Echo AIV, L.P., and the investment fund which owns FR Bison, which is seeking authorization to acquire GNI. Moreover, he stated that a further result of the BlackRock Transaction is that the Advisor became a subsidiary of BlackRock and that in his continuing role as a Managing Director of Advisor he, along with Mark Florian, will remain responsible for the Merger on behalf of Blackrock and the supervision of that investment after the closing of the Merger.

Witness Shockley stated that as a Managing Director of Advisor he can confirm that each of the statements regarding the manner in which First Reserve intends to manage its investment in GNI and Frontier reflected in his prefiled testimony and provided on the stand during the hearing of this matter remain true and fully applicable post-closing of the BlackRock Transaction. In sum, he stated that he affirmed that the exercise of ownership and control of GNI and Frontier by First Reserve will occur in the same manner that he testified to in this proceeding, to wit:

a. Composition of the GNI Board of Directors following closing of the GNI Transaction is still being determined; however, First Reserve expects to fill the board positions with qualified and experienced personnel who will provide sound governance for GNI going forward. First Reserve currently expects that some or all of the following people may be seated on the GNI Board: Mark Florian, Ryan Shockley, Matt Raben, Gregory Osborne, and Dave Cerotzke. Mr. Osborne is a current GNI Board member. Mr. Raben is a Managing Director of Advisor who was previously an employee of First Reserve and is very familiar with this transaction. The identity and qualifications of each of the other named individuals are discussed in the prefiled testimony in this proceeding. First Reserve's plans for appointing members to GNI's Board of Directors have therefore not changed as a result of the BlackRock Transaction.

b. First Reserve intends to maintain the capital provision process currently in place at Frontier and GNI. The recent refinancing and reorganization that was approved by the Commission in Docket No. G-40, Sub 133, provides sufficient capital to each GNI subsidiary, including Frontier, for execution of its forecasted growth plan. Frontier utility management will continue to be responsible for identifying any growth initiatives that require additional capital support beyond that forecasted growth plan. Consistent with current practice, a needs analysis together with assumptions underlying the project requiring additional capital support would be prepared by Frontier and shared with GNI. Again, consistent with current practice, the Board of Directors of GNI would then evaluate the proposal and, if pursued, work with management and First Reserve to identify the most appropriate source of funding. The primary change from the existing process is: (i) the GNI Board of Directors is controlled by First Reserve, which has a vested interest in operating a safe utility and funding growth as a result of its initial equity investment; and

(ii) improved access to equity funding from capital in a committed fund, as opposed to GNI having to pursue a public equity offering in a fairly illiquid stock.

c. First Reserve's hold period expectations are unchanged as a result of the BlackRock Transaction from what I described in my testimony in this proceeding.

Verified Statement of Ryan Shockley, at pp. 3-4.

Finally, witness Shockley stated that the verified statement filed by Anne Valentine Andrews confirms that he is also authorized to acknowledge and agree, on behalf of BlackRock, to the proposed Regulatory Conditions agreed to between the Public Staff and FREIF II Echo AIV, L.P., FR Bison, GNI, PHC Utilities, Inc. and Frontier in this proceeding.

In her verified statement, Anne Valentine Andrews stated that she is Managing Director for BlackRock, and the Chief Operating Officer of the BlackRock Infrastructure Investment Group. Further, Andrews stated that as a consequence of the BlackRock Transaction the Advisor became a subsidiary of BlackRock, and that Ryan Shockley, along with Mark Florian, is responsible for all matters regarding the ownership of GNI by a merger subsidiary of FR Bison. Finally, Andrews stated that BlackRock is in agreement with the testimony provided by witness Shockley.

On July 20, 2017, the Public Staff filed a letter stating that it had reviewed BlackRock's filing and believes that it addresses the matters enumerated in the Commission's BlackRock Order. Further, the Public Staff confirmed that the information provided by BlackRock is consistent with discovery responses provided to the Public Staff during its investigation of the proposed Merger, and that the Commission possesses sufficient jurisdictional control over BlackRock to ensure the enforcement of the proposed Regulatory Conditions against all parties.

Based upon the foregoing, the Commission finds and concludes that Frontier, FR Bison, and BlackRock are properly before the Commission with respect to the relief sought in the Amended Application and are in compliance with all merger filing requirements.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-12

The evidence supporting these findings of fact is set forth in the Amended Application, the Merger Agreement, and the testimony of Applicants' witnesses Shockley and Degenstein, and is uncontested.

Through the Amended Application and supporting testimony, the Applicants described the process for accomplishing the Merger and the resulting corporate and fund structure that will exist upon closing. The Amended Application and supporting testimony describes the proposed Merger transaction as follows:

> FREIF II Echo AIV, L.P., through its wholly-owned subsidiary FR Bison Holdings, will purchase 100% of the outstanding stock of GNI for $13.10 per share, following receipt of required shareholder and regulatory approvals. The Fund, through FR Bison Holdings, will own the existing GNI business. GNI will be the surviving

> entity of a merger as a subsidiary of FR Bison Holdings and will maintain its current corporate structure below GNI, as recently restructured and approved by the NCUC in Docket No. G-40, Sub 133.

(T. p. 118). This structure is confirmed by the provisions of the Merger Agreement itself, which is attached to the Application as Exhibit C.

The Amended Application and testimony of the Applicants' witnesses also explain how the proposed Merger will not change the corporate structure of GNI or Frontier. Applicants' witness Degenstein testified that following the Merger, GNI will continue to hold the sole interest in PHC Utilities, Inc., which in turn, holds the interests of Frontier as well as several other operating public utilities in Maine, Montana, and Ohio. Applicants' witness Shockley also testified that GNI and all of its subsidiaries will remain as currently structured – that is, as wholly owned subsidiaries of FR Bison Holdings, which was to be ultimately owned and controlled by First Reserve and, now, by BlackRock.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-18

The evidence for these findings of fact is set forth in the Amended Application, the Cost-Benefit Analysis, the agreed upon Regulatory Conditions and in the testimony of various witnesses for the Applicants and the Public Staff, and is uncontested.

According to Applicants' witnesses Shockley, Steele, and Sprague, the management and operations of Frontier will remain the same and Frontier will continue to be operated as a Commission-regulated North Carolina natural gas public utility. Witnesses Degenstein's and Sprague's testimony noted that following the Merger, the Commission will continue to have jurisdiction over Frontier, and thus will retain appropriate regulatory oversight over Frontier's utility operations.

The Amended Application notes that no changes to Frontier's rates, terms, and conditions of service are proposed in conjunction with the proposed Merger and that after closing of the Merger, Frontier will continue to provide utility service under its approved rates, terms, and conditions of service. Consistent with the Amended Application, Applicants' witness Steele testified that there is no proposal to change rates as part of the Merger, but should any changes to rates be proposed in the future, Frontier will, of course, seek Commission review and approval.

The Amended Application and testimony demonstrate that after closing of the Merger, the Commission will retain appropriate regulatory oversight over GNI and Frontier, and that GNI, the First Reserve Entities, and the Parent Entities, including BlackRock, are committed to ensuring that Frontier complies with all applicable rules and regulations, and all applicable orders of the Commission. Applicants' witnesses Steele and Sprague testified that following the Merger, Frontier will still be bound by all applicable Commission orders, as well as existing obligations under North Carolina laws, regulations, rules, and regulatory conditions.

In addition, for the reasons articulated in its Order Granting Waiver of Market Power Analyses Requirement, the Commission concludes that the proposed Merger will not result in materially increased market power of any of the parties to the detriment of customers.

Finally, the Regulatory Conditions agreed to by the Applicants and the Public Staff provide significant benefits for Frontier's ratepayers and are discussed in more detail below. The Commission finds these commitments by the Applicants sufficient to ensure that Frontier and GNI will continue to be operated in a manner consistent with the public interest following closing of the Merger.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19-21

The evidence for these findings of fact is set forth in the Amended Application, the Cost-Benefit Analysis, the agreed upon Regulatory Conditions and in the testimony of various witnesses for the Applicants and the Public Staff, and is uncontested.

The Amended Application lists a number of quantifiable and non-quantifiable benefits associated with the proposed Merger. These benefits include: (i) providing Frontier with First Reserve's management focus, experience, and financial resources; (ii) maintaining Frontier's rates, terms, and conditions of service, as well as its management and operational structure; (iii) improved access to capital for the expansion and maintenance of Frontier's system; and (iv) cost savings associated with GNI's transition from a publicly traded company to a privately held company.

In the Cost-Benefit Analysis and testimony, the Applicants also identified a number of benefits attendant to the proposed Merger. These benefits include: (i) a reduction in annual public company operating costs due to the Merger (Cost-Benefit Analysis, at p. 2); (ii) increased financial stability and an enhanced ability of GNI and Frontier to access capital (Cost-Benefit Analysis, at p. 3); (iii) resources to implement best practices, enhancements to system reliability, and realization of efficiencies (Cost-Benefit Analysis, at p. 3); (iv) increased allocation of management resources to improve operations and customer service (Cost-Benefit Analysis, at p. 3); (v) preservation of Frontier's management presence in North Carolina, resulting in the realization of local taxes, rents, and payroll (Cost-Benefit Analysis, at p. 4); (vi) improved access to capital which, combined with North Carolina economic incentives, should enhance Frontier's ability to extend infrastructure to unserved customers and under-developed areas of the State (Cost-Benefit Analysis, at p. 4); and (vii) maintenance of existing service by Frontier at existing rates, terms, and conditions of service (Cost-Benefit Analysis, at p. 4). The Applicants also agreed to waive any right to seek recovery of the acquisition premium or transaction fees associated with the proposed Merger (Cost-Benefit Analysis, at p. 5).

The testimony of the Applicants' witnesses also identified a number of benefits of the proposed Merger transaction. These identified benefits include: (i) an increased access to capital which will allow Frontier the opportunity to expand service to unserved customers and new service territories, make necessary system upgrades, and make enhancements to customer service; (ii) realization of operational savings and efficiencies associated with GNI transitioning from a publicly-held company to private ownership; (iii) access to FR Bison's experienced leadership, expertise, and support; and (iv) preservation of Frontier's existing rates and charges and Frontier remaining independent for accounting, operational, and ratemaking purposes.

In addition, Public Staff witnesses Perry, Larsen, and Craig testified that the agreed upon Regulatory Conditions and Cost-Benefit Analysis provide assurances that: (i) the Merger will result in Frontier continuing to operate and maintain its system and pursue growth opportunities, without impacting its base rates; (ii) there will be no adverse impact on Frontier's rates or service, and customers will receive a one-time bill credit; (iii) ratepayers will be protected from potential costs and risks associated with the Merger and, with certain exceptions, will be charged Frontier's current rates for a longer period of time than provided for in previous proceedings; (iv) Frontier will have increased access to capital to fund customer growth opportunities and ongoing investments required by federal or state regulations; and (v) the Commission and the Public Staff will receive annual audited financial statements of GNI.

Finally, the commitments by the Applicants in the Regulatory Conditions are significant in ensuring the realization of the benefits identified and discussed by the witnesses and the protection to ratepayers from possible costs and risks. These benefits include a requirement that Frontier provide a one-time bill credit of $100,000 to its North Carolina customers; a rate moratorium through December 31, 2021 (with certain exceptions); and the provision of additional monitoring and enforcement mechanisms.

Although First Reserve has no experience in managing natural gas local distribution companies, FR Bison has engaged the Luvian Partners, which has extensive experience in the regulated utility sector, to be a resource for First Reserve, GNI and Frontier. A key member of Luvian Partners is Dave Cerotzke whose experience includes serving as President and Chief Executive Officer of Energy West, Inc. (which is now GNI) from 2004 until 2007.

GNI witness Degenstein testified that capital investments for growth would be subject to an economic viability requirement. On examination by the Commission, witness Degenstein was asked about capital investments necessary to comply with federal pipeline safety regulations that would not be revenue producing. He responded that infrastructure needed to meet compliance with safety regulations "would not have an economic threshold to meet."

First Reserve witness Shockley, on examination by the Commission, was referred to references in the Public Staff's pre-filed testimony concerning "Frontier's pipeline safety issues" and to Regulatory Condition 14 and was asked if First Reserve understood the pipeline safety issues. He responded "Yes, we do." He was further asked if he was aware that the Commission enforces federal pipeline safety regulations and that any person who violates pipeline safety regulations is subject to a civil penalty. And he was also asked if First Reserve was aware of a Letter of Violation sent by the Commission's Pipeline Safety Section to Frontier. Witness Shockley responded in the affirmative to all of those questions. At the time, witness Shockley stated that he did not know if BlackRock was aware of the Letter of Violation. However, since the hearing, in the Verified Statement of Anne Valentine Andrews, Managing Director for BlackRock and the Chief Operating Officer of the BlackRock Infrastructure Investment Group, she stated that "BlackRock is in agreement with the testimony and verified statement provided by Ryan Shockley."

Regulatory Condition 10 deals with a Rate Case Moratorium and states that neither Frontier nor the Public Staff will request a change in Frontier's margin rates until after December 31, 2021. Regulatory Condition 10 makes an exception for the filing of a rate case prior to that date in the event that Frontier or the Public Staff believe that Frontier should implement a pipeline safety rate adjustment mechanism pursuant to G.S. 62-133.7A.

Taking into consideration the expert advice from Luvian Partners to First Reserve, the testimony form GNI witness Degenstein that capital expenditures for safety would not have to meet an economic viability standard, the acknowledgement by First Reserve witness Shockley that First Reserve was aware of pipeline safety issues, and the inclusion of an exception to the rate case moratorium in Regulatory Condition 10, the Commission concludes that adequate safeguards are in place to provide capital necessary to ensure that Frontier's system is operated safely.

With regard to Regulatory Condition 14, the Commission recognizes the efforts by Frontier and the Public Staff to draft a framework and a schedule to improve pipeline safety. However, the Commission makes clear that the timetable and actions established and agreed to in Regulatory Condition 14 in no way supersede the Commission's authority pursuant to G.S. 62-50 to enforce pipeline safety regulations. Regulatory Condition 14 does not take precedent over, nor does it relieve Frontier of the obligation to meet any timetable or action imposed by the Commission.

First Reserve's access to capital to support growth is a key benefit. Public Staff testified that Sempra, the prior owner of Frontier, "put $100 million in plant in the ground over a three year period." Frontier witness Sprague testified that, when Sempra sold Frontier to Energy West in 2007, it was an underdeveloped system that had maybe 300 customers. As a result, Sempra was forced to make a very significant write-down before selling Frontier to Energy West at a further loss. Since 2007, Frontier has grown its system to a little over 3,400 customers. Witness Sprague testified that Frontier's "five-year forecast continues that type of aggressive buildout." (T, pp. 84-85)

The Commission has carefully reviewed and considered all of the evidence set forth above describing the known and potential benefits of the proposed Merger and finds it to be credible and undisputed. Many of these benefits have been enhanced and guaranteed as a result of the agreed upon Regulatory Conditions.

The Commission, therefore, finds and concludes that the proposed Merger will result in a significant number of known and potential benefits, both quantifiable and non-quantifiable, as set forth in the Amended Application, the Cost-Benefit Analysis, the consistent and undisputed testimony of all witnesses, and the agreed upon Regulatory Conditions.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-26

The evidence supporting these findings of fact is contained in the Amended Application, the agreed upon Regulatory Conditions, the testimony of witnesses for the Applicants and the Public Staff, and the Commission's supervisory authority under Chapter 62 of the General Statutes over the rates, terms and conditions of service provided to the public by Frontier.

The legal standard applicable to this proceeding is set forth in G.S. 62-111(a) and requires the Commission to find that the proposed Merger is "justified by the public convenience and necessity." Upon such finding, the statute instructs that approval of the proposed Merger "shall be given." In prior merger proceedings the Commission has established a three-part test for determining whether a proposed utility merger is justified by the public convenience and necessity. That three-part test is as follows: (1) whether the merger would have an adverse impact on the rates and services provided by the merging utilities; (2) whether ratepayers would be protected as much as possible from potential costs and risks of the merger; and (3) whether the merger would result in sufficient benefits to offset potential costs and risks. See Order Approving Merger Subject to Regulatory Conditions and Code of Conduct (Duke-Progress Merger Order), issued June 29, 2012, in Docket Nos. E-2, Sub 998 and E-7, Sub 986, *aff'd*, In re Duke Energy Corp., 232 N.C. App. 573, 755 S.E.2d 382 (2014).

These questions are related to one another and together establish a reasoned framework upon which utility mergers may be evaluated. In making these assessments, the Commission has also examined factors such as whether service quality will be maintained or improved, the extent to which costs can be lowered and rates can be maintained or reduced, and whether effective regulation of the merging utilities will be maintained. See Order Approving Merger and Issuance of Securities, Docket No. E-7, Sub 596 (April 22, 1997).

Regarding the first question of the three-part test -- whether the merger would have an adverse impact on the rates and services provided by the merging utilities -- the Commission concludes, for the reasons explained below, that the Merger will not have an adverse impact on the rates and services provided by Frontier.

At the outset, the Commission notes that "[t]here is no proposal to change Frontier's rates, terms or conditions of service, management or operational structure as a result of the proposed transaction." (Application, ¶ 15, at p. 6) This representation is also confirmed by Regulatory Condition Nos. 12-14, 20-23, and 26-27, which specifically are aimed at ensuring that the Merger will have no adverse impact on Frontier's rates and services. Finally, the Cost-Benefit Analysis filed with the Application indicates that ratepayers will not be charged for direct or indirect merger costs such as the acquisition premium and transaction fees, which, instead, will be absorbed by FR Bison. (Cost-Benefit Analysis, at p. 5)

The Public Staff Joint Testimony recites the standard for approval of utility mergers under G.S. 62-111 and Commission precedent, describes, in some detail, the provisions of the agreed upon Regulatory Conditions that are designed to prevent any adverse consequences to customers, and ultimately recommends approval of the Merger subject to the restrictions and requirements of the agreed upon Regulatory Conditions.

Significantly, the evidence on these matters presented by the Applicants and the Public Staff, as set forth in the various documents and testimony discussed above, is uncontested. No other party submitted evidence suggesting that the proposed Merger will result in adverse consequences to the rates and services of Frontier.

Furthermore, as a matter of law, Frontier will remain subject to full regulation by the Commission. (See Application, ¶ 8, at p. 4) In particular, it is agreed by all parties that the Merger in no way diminishes the authority of the Commission to regulate service quality and rates for Frontier and, therefore, effective state regulatory oversight of Frontier will continue. The agreed upon Regulatory Conditions also contain provisions designed to ensure transparency and oversight and that the Commission's regulatory jurisdiction over Frontier is not diminished as a result of the Merger.

In this regard, the Commission notes that the provisions of Chapter 62 of the General Statutes provide the Commission with broad supervisory authority over Frontier including the authority to establish (and modify if necessary) the rates, terms, and conditions of service for Frontier. As such, and given the absence of any proposal in this docket to actually change Frontier's margin rates or services (other than the commitment by Frontier to credit its ratepayers with a one-time $100,000 bill credit – which is an immediate benefit to those ratepayers), the Commission finds no evidence that the Merger will increase rates or diminish services, or that the Commission's jurisdiction over Frontier as a regulated public utility will be adversely impacted in any way. Additionally, any currently unknown risks to customers arising out of the proposed Merger are sufficiently mitigated through the protections contained in the agreed upon Regulatory Conditions and the Commission's continuing regulatory jurisdiction over Frontier.

Based on the foregoing, the Commission finds and concludes that the there is no reasonable probability that the proposed Merger would pose risk of any real or potential adverse impact on the rates and services provided by Frontier to its customers.

Regarding the second question of the three-part test -- whether ratepayers would be protected as much as possible from potential costs and risks of the merger -- the Commission concludes, for the reasons explained below, that the ratepayers of Frontier will be protected as much as reasonably possible from potential costs and risks of the Merger.

Under G.S. 62-30, the Commission has general power and authority to supervise and control public utilities of North Carolina as may be necessary to carry out the laws providing for their regulation. G.S. 62-32 grants the Commission supervisory power over public utility rates and service, including the power to compel reasonable service and set reasonable rates. As noted above, paragraph eight of the Application provides that "Frontier will continue to provide natural gas service as a regulated utility pursuant to its CPCNs and under the jurisdiction of the Commission. The proposed transaction will not affect the Commission's regulatory jurisdiction over Frontier, and Frontier will continue to comply with all applicable regulations, rules, orders, and regulatory conditions issued by the Commission." This continuing and undiminished regulatory oversight will serve to protect ratepayers from any adverse consequences of the Merger.

Separate and apart from the Commission's inherent and continuing supervisory function, there is substantial evidence in this proceeding that ratepayers are and will be protected as much as possible from potential costs and risks of the Merger.

First, the Amended Application and the Cost-Benefit Analysis appended thereto as Exhibit E commit the Applicants not to seek recovery of several categories of Merger-related costs of which they possibly would otherwise be allowed to seek recovery. Specifically, the Applicants have expressly waived, in both the Amended Application and Cost-Benefit Analysis, any right to seek recovery of the acquisition premium or any transaction fees or change-of-control payments associated with the Merger. (See Cost-Benefit Analysis, at p. 5; Public Staff Joint Testimony, T, p. 187) This commitment is not insignificant inasmuch as the acquisition premium in this Merger is approximately $14.1 million and the transaction fees identified in the Cost-Benefit Analysis, which consist of payments to investment bankers, accountants, lawyers, and consultants, are estimated at $6 million. These commitments by the Applicants act to insulate ratepayers from the major costs of the Merger transaction itself.

Second, the agreed upon Regulatory Conditions also safeguard customers from potential adverse impacts on rates and services as a result of the Merger.

The Commission notes that several provisions of the General Statutes also serve to protect customers from potential negative consequences of the proposed Merger. These include: (i) G.S. 62-130 – Commission supervision over rates; (ii) G.S. 62-138 – requirement to obtain Commission approval over service contracts; (iii) G.S. 62-139 – prohibition of service at other than Commission approved rates; (iv) G.S. 62-140 –prohibition of discrimination; and (v) G.S. 62-153 – requirement to file affiliated contracts and to obtain approval for affiliated service contracts and payments to affiliates. Each of these statutory provisions either prohibits or mandates utility conduct for the purpose of assuring that rates charged to customers for utility services are just and reasonable.

Finally, the Public Staff Joint Testimony and the testimony of Applicants' witness Shockley support the conclusion that ratepayers are protected from potentially adverse impacts on rates, as well as the direct and indirect costs associated with the Merger. The Public Staff Joint Testimony discusses the various Regulatory Conditions and concludes that the Merger is consistent with the public interest and should be approved subject to the protections afforded customers provided by the Regulatory Conditions. In the rebuttal testimony of Applicants' witness Shockley, he describes the process that was undertaken by the Applicants and the Public Staff in formulating the Regulatory Conditions and indicates First Reserve's agreement with the Regulatory Conditions. Witness Shockley specifically testifies that First Reserve agrees that "the Regulatory Conditions are balanced and adequate to protect the interests of ratepayers and the Commission with respect to the proposed merger and to ensure that it will meet the Commission's enunciated standards for approval of proposed utility mergers." (T, p. 133)

Based on the foregoing, the Commission finds and concludes that potential risks of the Merger to ratepayers have been effectively mitigated by the commitments of the Applicants in the Amended Application and Cost-Benefit Analysis, as well as the testimony of Applicants' witnesses and the agreed upon Regulatory Conditions. Further, the Commission retains full power and authority to address any potential impact from the Merger on Frontier's ratepayers and to enforce the Regulatory Conditions.

Regarding the third question of the three-part test -- whether the merger would result in sufficient benefits to offset potential costs and risks -- the Commission concludes that the Merger will result in sufficient benefits to offset potential costs and risks resulting from the Merger. The evidence explaining these benefits is found in the Amended Application, the testimony of the witnesses for the Applicants and the Public Staff, and the Regulatory Conditions, and is previously discussed in the evidence and conclusions above regarding Findings of Fact Nos. 19-21.

The Commission has carefully reviewed and considered all of the evidence in this docket describing the known and potential benefits of the proposed Merger and finds it to be credible and undisputed. Frontier will have increased access to capital at the same or at a lower cost of capital than otherwise would be available without the Merger to support opportunities to expand service to unserved customers, make necessary system upgrades, and make enhancements to customer service. Frontier will also have access to the expertise and resources of First Reserve. Moreover, the Commission also concludes that the Regulatory Conditions agreed to by the Applicants and the Public Staff provide a number of benefits and safeguards to Frontier's ratepayers. These benefits include, but are not limited to: (i) a one-time bill credit of $100,000 to Frontier's North Carolina customers; (ii) a rate moratorium through December 31, 2021 (with certain exceptions); (iii) annual cost savings associated with GNI's transition from a publicly-traded company to a private company; (iv) reporting requirements to ensure appropriate accounting and allocation of costs; (v) assurances of continuing levels of service quality; (vi) a requirement that Merger-related direct and indirect expenses and any acquisition premium be excluded from recovery through customer rates; and (vii) the elimination of any possible future proposed adjustment to Frontier's rate base to recapture any past negative acquisition adjustments or asset impairment write downs from prior Frontier mergers.

Based upon this evidence, and the lack of any countervailing evidence, the Commission finds and concludes that Applicants have satisfied the third and final prong in the Commission's merger approval analysis and that benefits from the proposed Merger outweigh the potential costs and risks of the Merger.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

The evidence for this finding of fact is contained throughout the record in this docket and is identified in many of the preceding findings of fact and discussed in the evidence and conclusions for those findings of fact. This evidence, which is uncontested, supports the conclusion that the proposed Merger between FR Bison and GNI is justified by the public convenience and necessity.

The evidence in this proceeding, as reflected in the findings set forth above, establishes that there are a significant number of actual and potential benefits that will accrue to North Carolina, to Frontier, and most importantly, to the ratepayers of Frontier as a result of the proposed Merger. These benefits more than offset any potential risks or costs attendant to the proposed Merger, which are amply mitigated in any event by the Applicants' commitments concerning absorption of Merger costs and acquisition premiums, by the restrictions imposed on the Applicants' conduct by the agreed upon Regulatory Conditions, and by this Commission's continuing jurisdiction and authority over the rates, terms and conditions of service provided by Frontier. In addition, the Commission also concludes that service quality for Frontier will be maintained, that rates for Frontier ratepayers will be held steady (with certain exceptions) through December 31, 2021, and that effective regulation will be maintained for Frontier.

Accordingly, the Commission concludes that the Applicants' commitments in their Amended Application, testimony, and the agreed upon Regulatory Conditions are sufficient to ensure that: (1) the Merger will have no adverse impact on the rates and service provided to Frontier's ratepayers; (2) Frontier's ratepayers are protected as much as reasonably possible from potential costs and risks resulting from the Merger; and (3) the known and potential benefits from the Merger are sufficient to offset the potential costs and risks.

Therefore, based on all of the evidence presented in this proceeding, the Commission finds that approval of the proposed Merger between FR Bison and GNI is justified by the public convenience and necessity and should be granted, subject to all of the terms, conditions, and provisions of this Order, as well as the Regulatory Conditions.

IT IS, THEREFORE, ORDERED as follows:

1. That the application of FR Bison, Frontier, and BlackRock pursuant to G.S. 62 111(a) to engage in a business combination transaction shall be, and is hereby, approved subject to compliance with the provisions of this Order and the Regulatory Conditions attached hereto as Appendix A and incorporated herein.

2. That Frontier shall credit $100,000 to its North Carolina customers through a one-time bill credit to be completed by the last day of the first full month following closing of the Merger. Within 30 days after the bill credit is completed, Frontier shall file a report with the Commission detailing the amount of the bill credit.

3. That Merger and Merger-related direct and indirect expenses associated with the Merger, including change-in-control payments made to terminated executives, severance payments, regulatory process costs, and transaction costs, such as investment banker and legal fees for transaction structuring, financial market analysis, and fairness opinions based on formal agreements with investment bankers, shall be excluded from the regulated expenses of Frontier for Commission financial reporting and ratemaking purposes.

4. That the Applicants are precluded from recovering (1) any past negative acquisition adjustments or asset impairment write downs from prior Frontier mergers or (2) any portion of the acquisition premium resulting from this Merger.

5. That within 60 days of the Merger closing date, Frontier shall meet with the Public Staff to determine rate base or corresponding general ledger amounts by category and/or account, as applicable.

6. That within 60 days after the close of the Merger, Frontier shall file all affiliated service agreements, as provided by G.S. 62-153 and the Regulatory Conditions.

7. That Frontier shall file a summary report of its final accounting for Merger-related direct expenses within 120 days after the close of the Merger, and supplemental reports within 60 days after each quarter until such expenses cease.

8. That within 90 days after the close of the Merger, Frontier shall submit to the Public Staff Natural Gas Division and the Commission's Gas Pipeline Safety Section the scope of a review, critique, and report on the Frontier pipeline system policy and procedures, integrity management program, and staffing, inclusive of operational and safety personnel, along with a list of independent third-party consultants to provide such services. Within 30 days after such submission and after conferring with the Public Staff Natural Gas Division, the Commission's Gas Pipeline Safety Section and other Commission Staff, Frontier shall seek requests for proposals from those on an approved list of consultants and will select from the respondents and retain a consultant to conduct and prepare the review, critique, and report. Within seven (7) days of the issuance of the consultant's report, Frontier shall file the report with the Commission. Within 60 days of the issuance of the report, Frontier shall meet with the Public Staff Natural Gas Division, the Commission's Gas Pipeline Safety Section and other Commission Staff to determine how the recommendations in the report will be addressed.

9. That Frontier shall provide a copy of its Operating and Maintenance Manual to the Public Staff within 120 days of the close of the Merger and shall promptly notify the Public Staff in writing of any substantive changes thereafter.

10. That the Applicants are authorized to take such other and further actions as are reasonable and necessary to consummate the Merger set forth in the Merger Agreement subject to the terms hereof.

11. That Frontier shall file with the Commission copies of all orders from the state commissions in Montana, Ohio, and Maine related to the Merger, other than those Orders already filed with the Commission, within ten (10) days of issuance.

12. That the Applicants shall file written notice in this docket informing the Commission of the closing of the Merger within ten (10) days of the consummation of the Merger.

13. That this docket shall remain open pending the filing of such notice, and such other actions by the Commission that may be required.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of August, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

Former Commissioner Don M. Bailey and Commissioner Daniel G. Clodfelter did not participate in the issuance of this Order.

Appendix A

DOCKET NO. G-40, SUB 136
REGULATORY CONDITIONS

These Regulatory Conditions set forth commitments made by FREIF II Echo AIV, L.P. (FREIF), FR Bison Holdings, Inc. (FR Bison) (collectively the First Reserve Entities), Gas Natural, Inc. (GNI), PHC Utilities, Inc. (PHC), and Frontier Natural Gas Company (Frontier), as a precondition of approval of the application by Frontier and FR Bison pursuant to G.S. 62-111(a) for authority to engage in their proposed business combination transaction (Merger). These Regulatory Conditions, which become effective only upon closing of the Merger, shall apply jointly and severally to the First Reserve Entities, GNI, PHC, and Frontier (as well as any successor entities), and shall be interpreted in the manner that ensures Frontier's customers (a) are protected from any known adverse effects from the Merger, (b) are protected as much as possible from potential costs and risks resulting from the Merger, and (c) receive sufficient known and expected benefits to offset any potential costs and risks resulting from the Merger. To the extent there is a direct or indirect acquisition of any of the First Reserve Entities, GNI, PHC, or Frontier by BlackRock, Inc. (BlackRock), these Regulatory Conditions will continue to be fully applicable to the First Reserve Entities, GNI, PHC, and Frontier.

First Reserve Energy Infrastructure GP II, Limited (First Reserve), and First Reserve Energy Infrastructure GP II, L.P., and, solely to the extent that the acquisition of certain First Reserve entities by BlackRock (as described in the Amended Application) closes, BlackRock, as well as any additional or successor entities with control over any of the First Reserve Entities, GNI, PHC, or Frontier (collectively the Parent Entities), do hereby acknowledge and consent to these Regulatory Conditions agreed and entered into by FREIF, FR Bison, GNI, PHC, and Frontier (collectively the Subsidiary Entities). The Parent Entities further commit not to cause the Subsidiary Entities to violate such Regulatory Conditions for so long as such Regulatory Conditions remain in effect and applicable to the Subsidiary Entities. The consent and acknowledgment of the Parent Entities set forth above does not constitute a general consent to expansion of the North Carolina Utilities Commission's jurisdiction over the Parent Entities beyond that established by Chapter 62 of the North Carolina General Statutes.

For purposes of these Regulatory Conditions, the North Carolina Utilities Commission is referred to as "the Commission," and the Public Staff – North Carolina Utilities Commission is referred to as "the Public Staff." "Affiliate" shall mean First Reserve and any business entity of which ten percent (10%) or more is owned or controlled, directly or indirectly, by First Reserve, including, but not limited to, Frontier, PHC, GNI, and FR Bison. To the extent there is a direct or indirect acquisition by BlackRock of any of the Parent Entities, First Reserve Entities, GNI, PHC, or Frontier, this definition of "Affiliate" will also include BlackRock, as well as any business entity of which ten percent (10%) or more is owned or controlled, directly or indirectly, by BlackRock or its investment management subsidiaries (BlackRock Entities).

1. **Compliance with Sub 124 Stipulation.** Frontier shall continue to remain bound by the terms and conditions of the Stipulation entered into with the Public Staff on June 27, 2014, as amended on September 14, 2015 (collectively, the Sub 124 Stipulation), and filed in Docket No. G-40, Sub 124, to the extent that those terms and conditions are ongoing and are not clearly superseded by these Regulatory Conditions. The Sub 124 Stipulation is incorporated herein by reference.

2. **Compliance with Sub 133 Regulatory Conditions.** Frontier shall continue to remain bound by the Regulatory Conditions attached to the Commission's Order Granting Conditional Approvals, issued August 2, 2016, in Docket No. G-40, Sub 133 (Sub 133 Regulatory Conditions), to the extent that those conditions are ongoing and are not clearly superseded by these Regulatory Conditions. The Sub 133 Regulatory Conditions, with the exception of Attachment A thereto, are incorporated herein by reference. Attachment A to the Sub 133 Regulatory Conditions is superseded by Attachment A hereto.

3. **Measurement of Frontier Rate Base.** For North Carolina regulatory accounting, reporting, and ratemaking purposes, Frontier's rate base as of the Merger closing date shall be set at its net book value as of September 30, 2016, as reported in its financial statements and incorporated into the G.S.-1 Reports provided to the Public Staff and the Commission, plus charges and credits incurred in the normal course of utility business between September 30, 2016 and the Merger closing date. Within 60 days of the Merger closing date, Frontier shall meet with the Public Staff to determine rate base or corresponding general ledger amounts by category and/or account, as applicable.

4. **Merger-related Direct Expenses.** Direct expenses associated with the Merger will be excluded from the regulated expenses of Frontier for Commission financial reporting and ratemaking purposes. Direct merger costs are change-in-control payments made to terminated executives, severance payments, regulatory process costs, and transaction fees (such as investment banker and legal fees for transaction structuring, financial market analysis, and fairness opinions based on formal agreements with investment bankers). Frontier will file a summary report of its final accounting for Merger-related direct expenses within 120 days after the close of the Merger, and supplemental reports within 60 days after each quarter until such expenses cease.

5. **Merger Transition Costs.** Frontier shall report the actual transition costs as identified by category in the Cost-Benefit Analysis, Exhibit E to the Merger application, on its NCUC GS-1 Earnings Surveillance Report in accordance with generally accepted accounting principles and identify the North Carolina portions of these costs beginning with the first quarter after the Merger closes.

6. **Non-Consummation of Merger.** If the Merger is not consummated, neither the cost, nor the receipt, of any termination payment between FR Bison and GNI shall be allocated to Frontier or included in regulated expenses of Frontier for Commission financial reporting and ratemaking purposes. Frontier's customers shall not otherwise bear any direct expenses or costs associated with a failed merger.

7. **Inclusion of Cost Savings in Future Rate Proceedings.** For purposes of future general rate case proceedings for Frontier, Frontier and the Public Staff shall not be limited to or constrained by the provisions of these Regulatory Conditions in asserting or sustaining arguments regarding the proper treatment of merger cost savings in setting just and reasonable rates for Frontier.

8. **Merger-related Cost Savings.** In order to ensure that Frontier's ratepayers receive a benefit from Merger-related cost savings identified in the Cost-Benefit Analysis, Exhibit E to the Merger application, Frontier shall credit $100,000 to its North Carolina customers through a one-time bill credit to be completed by the last day of the first full calendar month after the closing. The bill credit shall be allocated to the rate schedules by the non-gas cost margin of each rate schedule. The total allocated credit in each rate class will be divided by the total volume of gas from the latest calendar 12 months of usage prior to the date of closing that is available to arrive at a unit credit rate for each rate schedule. Customers within each rate class will be credited an amount equal to the class unit credit rate times each individual customer's volume from the latest calendar 12 months available. Within 30 days after the bill credit is completed, Frontier shall file a report with the Commission detailing the amount of the bill credit by rate schedule.

9. **Hold Harmless Commitment.** The Merger shall be effectuated in a manner designed to prevent harm to Frontier's ratepayers, although it is recognized that it is possible that matters not currently foreseeable could have the potential to negatively impact Frontier ratepayers in the future. Notwithstanding this, Frontier, the First Reserve Entities, GNI, and PHC (as well as any successor entities exercising control over Frontier) shall take all

such actions as may be reasonably necessary and appropriate to hold Frontier's customers harmless from the effects of the Merger.[1]

10. **Rate Case Moratorium.** Neither Frontier nor the Public Staff will request a change in Frontier's margin rates until after December 31, 2021, except as set forth below. For purposes of this provision, the margin rate is defined as the tariff rate less the benchmark cost of gas and temporary increments and/or decrements imposed pursuant to G.S. 62-133.4 or Commission Rule R1-17(k). The exceptions to the moratorium imposed by this Condition are as follows: (a) Should Frontier or the Public Staff believe that Frontier should implement a pipeline safety rate adjustment mechanism pursuant to G.S. 62-133.7A, either party shall have the right to apply to or petition the Commission to initiate a general rate case proceeding; and (b) effective July 1, 2019, should Frontier's rolling twelve-month earned return on average rate base, based on a reasonable pro forma capital structure and reasonable regulatory adjustments, exceed 12.00% for two quarters in any consecutive four-quarter period, the Public Staff shall have the right, after notice to and consultation with Frontier's management, to petition the Commission to initiate a general rate case proceeding.

11. **Distributions to GNI and PHC.** Frontier shall not pay to GNI (directly or through PHC) any distribution exceeding 100% of Frontier's net income calculated on a two-year rolling average basis. In addition, Frontier shall limit cumulative distributions paid to GNI (directly or through PHC) subsequent to closure of the Merger to (i) the amount of its retained earnings on the day prior to the closure of the Merger, plus (ii) any future earnings recorded by Frontier subsequent to closure of the Merger. Frontier shall not make any distributions to any Affiliates other than PHC and GNI, unless approved by the Commission. The Commission retains the right to impose future limitations on the distributions of Frontier if the public interest requires, as provided pursuant to applicable law and prior Commission orders.

12. **Obligations with Affiliates.** Frontier will not make a loan to any Affiliate, issue a guarantee for an obligation of any Affiliate, or otherwise assume any obligation of any Affiliate without prior Commission approval.

13. **Capital Budgets.** Frontier shall maintain a level of capital and operational support in North Carolina necessary to provide safe, efficient, and reliable service at reasonable rates. By January 31, 2018, Frontier shall provide to the Commission and to the Public Staff, on a confidential basis and for informational purposes, its five year projected capital budget for new, expanded, or upgraded natural gas facilities in North Carolina, and updates shall be provided to the Commission and to the Public Staff by June 30 every year thereafter until relieved of this requirement by future Commission order.

14. **Pipeline Safety.** Frontier shall budget and expend sufficient funds in order to be in compliance with all federal gas pipeline safety laws and regulations. Within 90 days after the close of the Merger, Frontier will submit to the Public Staff Natural Gas Division

[1] The First Reserve Entities reserve their right to dispute future assertions by the Public Staff that any particular future action or event may cause or represent harm to Frontier's ratepayers attributable to the Merger for which relief should be granted under this Condition.

and the Commission Staff the scope of a review, critique, and report on the Frontier pipeline system policy and procedures, integrity management program, and staffing, inclusive of operational and safety personnel, along with a list of independent third-party consultants to provide such services. Within 30 days after such submission and after conferring with the Public Staff Natural Gas Division and the Commission Staff, Frontier will seek requests for proposals from those on an approved list of consultants and will select from the respondents and retain a consultant to conduct and prepare the review, critique, and report. Within seven (7) days of the issuance of the consultant's report, Frontier will file the report with the Commission. Within 60 days of the issuance of the report, Frontier will meet with the Public Staff Natural Gas Division and the Commission Staff to determine how the recommendations in the report will be addressed.

15. **Notice of Certain Investments.** Whenever one of the Parent Entities or First Reserve Entities (or BlackRock Entities, if applicable) makes any new or increased direct or indirect investment in a business entity where: (a) such investment appears or will appear on the books of FR Bison, PHC, or GNI, or will otherwise have an effect on the books, costs, rates, revenues, charges, obligations, services, capitalization, or indebtedness of Frontier, and (b) the amount of such investment is equal to ten percent (10%) or more of GNI's book capitalization, the investing entity shall file or cause to be filed, as soon as practicable following Board or other approval of the subject transaction and any public announcement thereof (if one is made), a notice of the investment with the Commission. The notice shall include a full description of the investment and an explanation of how it will be accounted for in the investing entity's books and records.

16. **Notice of Certain PHC Investments.** Frontier shall file a notice with the Commission, subsequent to PHC Board approval and as soon as practical following any public announcement (if one is made), of any new investment in a regulated utility.

17. **Notice by Frontier of Default or Bankruptcy of Affiliate.** If an Affiliate of Frontier experiences a default on an obligation that is material to GNI or FR Bison or files for bankruptcy, and such bankruptcy is material to GNI or FR Bison, Frontier shall notify the Commission of the event in advance, if possible, or, if not, as soon as possible but not later than ten (10) days after such event. For purposes of this section, materiality shall be any default or bankruptcy that would be required to be disclosed in the audited financial statements of GNI.

18. **Common Equity Capital.** Until the final order is issued in Frontier's next general rate case, Frontier will maintain common equity capital at levels equal to or greater than 45% of total adjusted capital (including common equity, long-term debt, long-term capital leases, and current maturities of long-term debt). No equity distributions, whether by dividend or other form, will be allowed that would result in equity capital falling below this minimum level during the specified period, without prior approval of the Commission. Notwithstanding the foregoing, Frontier shall maintain the right to petition the Commission for an exception to this condition.

19. **Post-Closing Financial Information.** Frontier shall file pre- and post-Merger closing balance sheets and the closing journal entries, including relevant descriptions and

disclosures for the transactions recorded, for GNI, PHC, and itself, as soon as practicable but not later than the end of the second full quarter following the close of the Merger.

20. **Regulatory Reporting Requirements.** Frontier shall comply with all regulatory reporting requirements shown on Attachment A hereto.

21. **Regulatory Staffing.** Frontier shall maintain sufficient, adequately trained personnel to ensure that regulatory reporting requirements are complied with in a timely and accurate manner, including the reporting requirements listed on Attachment A hereto. Frontier shall notify the Commission and the Public Staff when there is any change in regulatory or operational personnel at the management/supervisor level. Each year by June 30, Frontier shall provide the Commission and the Public Staff with an updated directory of regulatory and operational personnel, including phone numbers and e-mail addresses.

22. **Operating and Maintenance Manual.** Frontier shall provide a copy of its Operating and Maintenance Manual to the Public Staff within 120 days of the close of the Merger and shall promptly notify the Public Staff in writing of any substantive changes thereafter.

23. **Overall Service Quality.** Upon consummation of the Merger, Frontier shall continue its commitment to provide safe and reliable natural gas service.

24. **Meetings with Public Staff.** GNI and Frontier shall meet annually with the Public Staff to discuss Frontier's financial condition and results, service quality initiatives and results, pipeline safety, and potential new tariffs.

25. **Service Company Formation.** Frontier shall notify the Commission of any plans of any Affiliate to form a service company that, to the best knowledge of the First Reserve Entities, could potentially cause federal preemption of the Commission's jurisdiction over Frontier or would affect, take services from, or provide services to Frontier at least sixty (60) days prior to the formation of such service company. Frontier will take all such actions as the Commission finds necessary and appropriate to hold North Carolina ratepayers harmless from any federal preemption that may be triggered by the formation of a service company.

26. **Charges for and Allocations of the Costs of Affiliate Transactions.** Frontier will develop, after consultation with the Public Staff, a Cost Allocation Manual (CAM) pursuant to which the costs of Affiliate transactions will be directly charged where practicable. The CAM shall encompass transactions and allocations occurring (a) at the FREIF level and below, and (b) with any Affiliate with which Frontier has a frequent or continuing cost allocation or transaction relationship, either directly or indirectly through FREIF or a direct or indirect subsidiary of FREIF. Frontier shall file with the Commission such CAM by December 31, 2018. Frontier shall review the propriety of the Affiliates included and the allocation bases and factors annually, and file with the Commission an updated CAM when revised.

27. **Affiliated Agreements.** Frontier shall file pursuant to G.S. 62-153 agreements for the provision and receipt of goods or services between and among Frontier and its Affiliates.

All such agreements that involve payment of fees or other compensation by Frontier shall require acceptance and authorization by the Commission, and shall be subject to any other Commission action required or authorized by North Carolina law and the Rules and orders of the Commission. Prior to making any changes to existing agreements, Frontier shall file such changes with the Commission. Frontier shall have the responsibility for determining whether or not such agreements are made with Affiliates, but will not be penalized for inadvertent failures to file any such agreement on a timely basis, if it can show that it could not have reasonably known that such agreement was with an Affiliate.[1]

28. **Access to Books and Records.** In accordance with and to the extent provided by North Carolina law, the Commission and the Public Staff shall continue to have access to the books and records of Frontier and its Affiliates.

29. **Changes to Board of Directors or Management.** Frontier shall notify the Commission within ten (10) days of any changes to the Board of Directors or management of FR Bison, GNI, PHC, or Frontier.

30. **Notice and Consultation with Public Staff Regarding Proposed Structural and Organizational Changes.** Upon request, FR Bison, GNI, and Frontier shall meet and consult with, and provide requested relevant data to, the Public Staff regarding plans for significant changes in Frontier's or any of its Affiliates' organization, structure, and activities which are reasonably anticipated to effect Frontier; the expected or potential impact of such changes on Frontier's rates, operations and service; and proposals for assuring that such plans do not adversely affect Frontier's customers. Frontier shall inform the Public Staff promptly of any such events and changes.

31. **Mergers and Acquisitions.** For any proposed merger or other business combination[2] that would affect Frontier, Frontier shall file an application for approval pursuant to G S. 62-111(a) at least 180 days before the proposed closing date for such merger or other business combination.

32. **Audited Financial Statements.** By the end of the first quarter of each calendar year, Frontier will provide to the Public Staff audited financial statements of GNI for the preceding calendar year.

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[1] This exception is considered reasonable due to the fact that BlackRock, through its investment management subsidiaries, manages investments in a broad range of companies that may conceivably interact with GNI, PHC, and/or Frontier on an arms-length basis in the ordinary course of business and whose affiliated nature may not be readily or quickly known to the parties involved in such interactions.

[2] For purposes of these Regulatory Conditions, a "merger or other business combination" is defined as not simply an investment in a business entity, but as a transaction or other event in which either (1) an acquirer obtains control of one or more business entities, or (2) two or more previously separate business entities merge into one with newly defined or established control authority.

Attachment A

Item #	Description	Frequency	Deadline	Requirement	Docket/Statute/Rule Reference
1.	FERC Form 2 Report	Annually	April 30	One copy filed with PS Acctng. Div. Copies provided to PS Natural Gas Div. and NCUC Fiscal Management Div.	Rule R6-5(9)
2.	Financial & Operating Report	Monthly	45 days	Provided to PS Acctng. Div.	G.S. 62-36. Official NCUC Request.
3.	Deferred Account Report	Monthly	45 days	Filed w/Chief Clerk. Detailed workpapers provided to PS Acctng. Div.	Rule R1-17(k)(5)(c)
4.	Annual Review Of Gas Costs Filing	Annually	December 1	Filed w/Chief Clerk	G.S. 62-133.4(c) and Rule R1-17(k)
5.	Daily Dispatch Report for last day of month	Monthly	3 days	Filed with Chief Clerk and provided to PS Natural Gas Div.	Rule R6-5(7)
6.	Source of Supply, Sales, Customers and Transportation	Monthly	45 days	Filed w/Chief Clerk	G-100, Sub 24A
7.	Customer Bill Format	Each Time Changed		Filed w/Chief Clerk and provided to PS Natural Gas Div.	Rule R6-5(3)
8.	Natural Gas Bond Fund Economic Feasibility Report	Biennially	November 30	Filed w/Chief Clerk	Rule R6-93
9.	Meter Report	Monthly	30 days	Filed w/Chief Clerk and provided to PS Natural Gas Div.	Rule R6-5(7)b
10.	Contracts with Customers	Each Occurrence	Prior to effective date	If term > 1 year, then filed w/ Chief Clerk for approval. If term < 1 year, then provide to PS Acctng. Div. in Annual Review.	Rule R6-5(2)

Item #	Description	Frequency	Deadline	Requirement	Docket/Rule Reference
11.	Incentive Plans	Each Program	Prior to Offer	Filed w/Chief Clerk. Approval required.	G.S 62-140(c), Rule R6-95
12.	Regulatory Fee Report	Quarterly	45 days	Filed w/NCUC Fiscal Management Div.	Rule R15-1
13.	Notice of Supplier Refunds Received	Each Occurrence	1 week	Filed w/Chief Clerk	G-100, Sub 57
14.	Construction Budget	Annually		Filed w/Chief Clerk	Rule R6-5(6)
15.	GS-1 Report[1/]	Quarterly	45 days	Provided to NCUC Operations Div., NCUC Fiscal Management Div., and PS Acctng. Div.	G.S. 62-36. NCUC Official Request by letter dated April 25, 1972
16.	Gas Pipeline Safety Reports	Various	Various	Filed w/Chief Clerk, otherwise contact the NCUC Pipeline Safety Div.	G.S. 62-50, Rules Chapter 6, and G-100, Sub 92
17.	Annual Affiliated Transactions Report	Annually	March 31	Filed w/Chief Clerk	NCUC Final Order Docket No. G-40, Sub 133
18.	Annual Financing Forecast	Annually	March 31	Provided to PS Economic Research Div. and Acctng. Div.	NCUC Final Order Docket No. G-40, Sub 133
19.	Audited Financial Statement of Gas Natural, Inc.	Annually	March 31	Provided to PS Acctng. Div.	NCUC Final Order Docket No. G-40, Sub 136
20.	Cost Allocation Manual (CAM)	As revised [2/]	As revised[2/]	Filed w/Chief Clerk	NCUC Final Order Docket No. G-40, Sub 136
21.	Projected Capital Budget	Annually	June 30	Provided to PS Acctng. Div.	NCUC Final Order Docket No. G-40, Sub 136

[1/] Frontier will begin filing the revised GS-1 Report format as of March 31, 2017, and will file on a quarterly basis going forward.
[2/] Frontier will develop and file a Cost Allocation Manual by December 2018, and will file any revisions on an annual basis going forward.

Item #	Description	Frequency	Deadline	Requirement	Docket/Rule Reference
22.	G-2 Report -- Planned construction of high pressure (>100 psi) pipeline	Each occurrence	30 days prior	Filed w/Chief Clerk	Docket No. G-100, Sub 92
23.	G-3 Report – Certifies construction of high pressure (>100 psi) pipeline	Each occurrence	60 days from completion	Filed w/Chief Clerk	Docket No. G-100, Sub 92
24.	Residential Disconnection for Non-payment	Monthly	2 weeks from end of month	Filed w/Chief Clerk	Docket No. M-100, Sub 61A

DOCKET NO. G-9, SUB 712
DOCKET NO. G-5, SUB 581
DOCKET NO. G-41, SUB 52
DOCKET NO. G-40, SUB 143
DOCKET NO. G-100, SUB 53

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Joint Petition of Piedmont Natural Gas Company, Inc., Public Service Company of North Carolina, Inc., Frontier Natural Gas Company, and Toccoa Natural Gas for Waiver of Reporting Requirement and Repeal of Commission Rule R6-5(11)	)))))	ORDER CANCELLING REPORTING REQUIREMENT AND REPEALING COMMISSION RULE R6-5(11)

BY THE CHAIRMAN: On June 15, 1989, the North Carolina General Assembly enacted G.S. 62-36A, later recodified as G.S. 62-36.1. The statute, among other things, directed the Commission to adopt rules requiring natural gas local distribution companies (LDCs) to file biennial reports describing the LDCs' plans to provide natural gas service to areas in their franchised service territories that were not receiving gas service (expansion reports).

On October 25, 1989, in Docket No. G-100, Sub 53, the Commission issued an Order adopting Commission Rule R6-5(11). As subsequently amended, the rule requires the LDCs to file biennial expansion reports on or before October 31. The LDCs next expansion reports are due on October 31, 2017.

By Session Laws 2014-120, s. 10(a), effective September 18, 2014, the General Assembly repealed G.S. 62-36.1.

On October 13, 2017, Piedmont Natural Gas Company, Inc., Public Service Company of North Carolina, Inc., Frontier Natural Gas Company, and Toccoa Natural Gas (Petitioners) filed a joint petition requesting that the Commission waive the requirement that the Petitioners file an expansion report on October 31, 2017, and repeal Commission Rule R6-5(11). In support of their petition, they recite the history of G.S. 62-36.1 and Rule R6-5(11), and submit that the underlying rationale for Rule R6-5(11) no longer exists due to the legislature's repeal of G.S. 62-36.1. Petitioners further state that the Public Staff was consulted by Petitioners and has indicated that it supports the relief requested by Petitioners.

Based on the petition and the record, the Chairman finds good cause to cancel the requirement that the Petitioners file expansion reports by October 31, 2017, and to repeal Commission Rule R6-5(11).

IT IS, THEREFORE, ORDERED as follows:

1. That the requirement of Rule R6-5(11) that Piedmont Natural Gas Company, Inc., Public Service Company of North Carolina, Inc., Frontier Natural Gas Company, and Toccoa Natural Gas file expansion reports by October 31, 2017, shall be, and is hereby, cancelled.

2. That Commission Rule R6-5(11) shall be, and is hereby repealed.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of October, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

NATURAL GAS – RATE INCREASE

DOCKET NO. G-39, SUB 38

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Cardinal Pipeline Company, LLC, for an Adjustment In its Rates and Charges	))	ORDER DECREASING RATES

HEARD: Tuesday, June 27, 2017, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners Jerry C. Dockham and James G. Patterson

APPEARANCES:

For Cardinal Pipeline Company, LLC:

Robert W. Kaylor, P.A., 353 East Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Gina C. Holt, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: On February 7, 2017, Cardinal Pipeline Company, LLC (Cardinal or the Company), gave notice pursuant to Commission Rule R1-17(a) of its intent to file a general rate case. Also on February 7, 2017, Cardinal filed a separate Request for Waivers of three Commission requirements pertaining to the filing of a general rate case: the Commission Rule R1-17(b)(13)(d) requirement to publish notice to customers in local newspapers and the NCUC Form G-1, Rate Case Information Report requirements to file Item 25 – Accounts Payable and Item 26 – Lead/Lag Study.

The Commission granted the three waivers requested by Cardinal in its Order Granting Request for Waivers issued March 1, 2017.

On March 15, 2017, Cardinal filed its verified application for an adjustment in its rates and charges (Application) seeking a general decrease in its rates and charges for natural gas service. Included with the Application were the information and data required by the NCUC Form G-1 and the direct testimony and exhibits of Company witnesses Ronald P. Goetze, Manager of Rates and Regulatory for Cardinal Operating Company, LLC, and Michael J. Vilbert, Ph.D., an economist.

On March 21, 2017, Piedmont Natural Gas Company, Inc. (Piedmont), filed a petition to intervene, which was granted by the Commission on March 23, 2017.

On March 22, 2017, Public Service Company of North Carolina, Inc. (PSNC), filed a petition to intervene, which was granted by the Commission on March 23, 2017.

NATURAL GAS – RATE INCREASE

On April 18, 2017, the Commission issued its Order Setting Investigation and Hearing, Implementing Proposed Rates, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Notice. The Commission declared the Company's Application to be a general rate case pursuant to G.S. 62-137 and allowed the implementation of the requested rate decrease on May 1, 2017, the Company's proposed effective date of the rate change, subject to modification pursuant to further investigation and a final order of the Commission in this docket. In addition, the Commission set the matter for hearing, required the Company to give its customers notice of the hearing, established discovery guidelines, and established dates for interventions and for the prefiling of direct testimony by the Public Staff and intervenors, and a date for the prefiling of rebuttal testimony by the Company.

On April 26, 2017, Cardinal filed a revised tariff sheet pursuant to the Commission's April 18, 2017 Order in this docket, which placed Cardinal's proposed rates into effect on May 1, 2017.

On June 7, 2017, the Public Staff filed, on behalf of all the parties, a Motion for Extension of Time to File Testimony, which the Commission granted on June 8, 2017.

On June 9, 2017, Cardinal, the Public Staff, Piedmont, and PSNC (Stipulating Parties) filed a Stipulation in settlement of all aspects of this proceeding.

On June 26, 2017, the Stipulating Parties filed a Joint Motion for Witnesses to Be Excused from Evidentiary Hearing, which also requested that all pre-filed testimony, exhibits, and the Stipulation be received into evidence. The motion was granted by the Commission on the same date.

On June 27, 2017, the case came on for hearing as scheduled in Raleigh. No public witnesses appeared. At the hearing, the Commission admitted into evidence all pre-filed testimony and exhibits filed in this docket, and Cardinal moved the admission of the Stipulation into the record, which was granted.

On July 19, 2017, the Stipulating Parties filed a Joint Proposed Order.

Based upon the verified Application, the testimony and exhibits received into evidence, the Stipulation, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Cardinal is a limited liability company formed under the North Carolina Limited Liability Company Act. The members of Cardinal are PSNC Cardinal Pipeline Company, a wholly owned subsidiary of PSNC; Piedmont Intrastate Pipeline Company, a wholly owned subsidiary of Piedmont; and TransCardinal Company, LLC, a wholly owned subsidiary of Transcontinental Gas Pipe Line Company, LLC. Cardinal's principal place of business is located at the offices of its operator, Cardinal Operating Company, LLC, at 2800 Post Oak Boulevard, Houston, Texas.

2. Cardinal is a public utility within the meaning of G.S. 62-3(23).

3. The Commission has jurisdiction over, among other things, the rates and charges, rate schedules, classifications and practices of public utilities, including Cardinal.

4. In the Application in this docket, Cardinal sought a general decrease in its rates and charges in the amount of $1,976,070 per year. Cardinal also requested authority to defer certain pipeline integrity management costs for proposed future collection and to implement new depreciation rates.

5. Cardinal is properly before the Commission for a determination of the justness and reasonableness of its rates and charges, rate schedules, classifications and practices as regulated by the Commission under Chapter 62 of the General Statutes of North Carolina.

6. The appropriate test period for use in this proceeding is the twelve months ended December 31, 2016, adjusted for certain known and measurable changes through March 31, 2017.

7. The Stipulation executed by Cardinal, the Public Staff, Piedmont, and PSNC is unopposed by any party. The Stipulation settles all matters in this docket.

8. The Stipulation provides for a decrease of $3,769,850 in annual revenues for the Company, which decrease is just and reasonable and appropriate for use in this docket.

9. The original cost of Cardinal's property used and useful, or to be used and useful within a reasonable time after the test period, in providing natural gas utility service to the public within North Carolina, less that portion of the cost that has been consumed by depreciation expense, in the amount of $ $66,978,628, as described and set forth in Paragraph 2 and Exhibit A of the Stipulation, is reasonable and appropriate for use in this docket.

10. Cardinal's total annual cost of service and revenue requirement, as set forth in Paragraphs 3 and 4 and Exhibit A of the Stipulation, are reasonable and appropriate for use in this docket.

11. The depreciation rates set forth in Cardinal's Depreciation Rate Study filed on October 26, 2016, in Docket No. G-39, Sub 37, and accepted by the Commission for compliance with Commission Rule R6-80 by Order dated February 21, 2017, are just and reasonable and appropriate for use in this docket.

12. The Company's operating expenses, including actual investment currently consumed through reasonable actual depreciation, as set forth in Paragraph 4 and Exhibit A of the Stipulation, are reasonable and appropriate for use in this docket.

13. The North Carolina state corporate income tax rate of 3% and the federal income tax rate of 35%, as set forth in Paragraph 4 of the Stipulation, are reasonable and appropriate for use in determining income taxes in this docket.

14. The debt cost of 4.27%, as provided in Paragraph 4 of the Stipulation, is just and reasonable and appropriate for use in this docket.

15. The rates set forth on Exhibit B of the Stipulation are just and reasonable and appropriate for use in this docket.

16. The allocation methodology employed by the Company in determining the cost of service applicable to each zone, as shown on Exhibit A of the Stipulation and as applied to the specific rates shown on Exhibit B of the Stipulation, is just and reasonable and appropriate for use in this docket.

17. The zonal allocation factors, as set forth in Exhibit A of the Stipulation, are just and reasonable and appropriate for use in this docket.

18. The Excess Deferred Income Tax (EDIT) amortization adjustment, as set forth in Paragraph 5 of the Stipulation, is just and reasonable and should be approved.

19. The use of an AFUDC rate of 7.17% effective with the date of the rates approved in this proceeding, as set forth in Paragraph 7 of the Stipulation, is just and reasonable and should be approved.

20. Cardinal's proposal to defer certain pipeline integrity operating and maintenance (O&M) expenses is reasonable and appropriate and should be approved and implemented as described in Paragraph 8 of the Stipulation.

21. Cardinal's agreement to file its next general rate case no later than March 15, 2022, and to provide the Stipulating Parties, one month prior to the filing date, with a rough outline of the rate case, including the period selected as the test year for the rate case, is just and reasonable and should be approved.

22. All of the provisions of the Stipulation are just and reasonable under the circumstances of this proceeding and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-5

The evidence supporting these findings of fact is contained in Cardinal's verified Application, the testimony and exhibits of the Company's witnesses, the NCUC Form G-1 that was filed with the Application, and the record as a whole. These findings are essentially informational, procedural, or jurisdictional in nature and are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

Cardinal filed its application and exhibits using a test period of the twelve months ended December 31, 2016. The Stipulation is based upon the test period utilized by Cardinal, adjusted for certain known and measurable changes through March 31, 2017. This test period was not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

This finding is supported by the Stipulation as well as representations made by Cardinal and the Public Staff at the hearing of this matter.

The Stipulation recites that it was filed on behalf of Cardinal, the Public Staff, Piedmont, and PSNC. The Stipulation provides that it represents a settlement of all the issues in the proceeding. This finding is not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

This finding is supported by the Application, the direct testimony of Company witness Goetze, and the Stipulation.

Goetze Exhibit RG-1, Schedule 8, Page 1 indicates that Cardinal filed for an annual revenue decrease of $1,976,070. The Stipulation in Paragraph 4 (a) indicates that the Stipulating Parties agree to a total annual cost of service and revenue requirement for Cardinal of $12,591,640, which represents a $3,769,850 decrease from the total annual cost of service and revenue requirement as of March 31, 2017, the end of the updated test period. The amounts set forth in Paragraph 4 (a) of the Stipulation are the result of negotiations among the parties and are not opposed by any party.

The Commission has carefully reviewed these amounts and concludes that they are just and reasonable and appropriate for use in this docket and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is contained in Cardinal's verified Application, the testimony and exhibits of the Company's witnesses, and the Stipulation.

The reasonable original cost of Cardinal's property used and useful, or to be used and useful within a reasonable time after the test period, in providing natural gas utility service to the public within North Carolina, less that portion of the cost that has been consumed by depreciation expense, is described and set forth in Paragraph 2 and Exhibit A of the Stipulation.

Cardinal's original cost rate base used and useful in providing service in North Carolina of $66,978,628, consisting of gas plant-in-service of $152,291,065 and working capital of $316,161 reduced by accumulated depreciation of $55,739,553 and accumulated deferred income taxes of $29,889,045, is the result of negotiations among the parties and is not opposed by any party. The Commission has carefully reviewed the above amounts and concludes that they are reasonable and appropriate for use in this docket and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence supporting this finding of fact is contained in Cardinal's verified Application, the testimony and exhibits of the Company's witnesses, and the Stipulation.

The total annual cost of service and revenue requirement under Cardinal's stipulated proposed rates are set forth in Paragraphs 3 and 4 and Exhibit A of the Stipulation. The amounts shown on Exhibit A of the Stipulation are the result of negotiations among the parties and are not opposed by any party. The Commission has carefully reviewed these amounts and concludes that they are reasonable and appropriate for use in this docket and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

This finding is supported by the Application, the direct testimony of Company witness Goetze, and the Company's most recent Depreciation Rate Study filed on October 26, 2016, in Docket No. G-39, Sub 37. In that docket, the Commission issued an order on February 21, 2017, concluding that the Depreciation Rate Study should be accepted for compliance with Commission Rule R6-80, and that it should be considered for implementation in conjunction with Cardinal's next general rate case, which is the instant docket. The Stipulating Parties have incorporated these depreciation rates into the annual cost of service contained in the Stipulation. These depreciation rates are not opposed by any party. The Commission concludes that these depreciation rates are just and reasonable and appropriate for use in this docket and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is contained in Cardinal's verified Application, the testimony and exhibits of the Company's witnesses, and the Stipulation.

Cardinal's reasonable operating expenses, including actual investment currently consumed through reasonable actual depreciation, are set forth in Exhibit A of the Stipulation. The amounts shown on Exhibit A of the Stipulation are the result of negotiations among the parties and are not opposed by any party. The Commission has carefully reviewed these amounts and concludes that they are reasonable and appropriate for use in this docket and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The support for this finding is contained in Paragraph 4(e) of the Stipulation. The Stipulating Parties agreed that income taxes should be determined using the North Carolina state corporate income tax rate of 3% and the federal income tax rate of 35%, as set forth in Paragraph 4(e). Income taxes calculated according to Paragraph 4(e) as set forth on Exhibit A of the Stipulation, are reasonable and appropriate for use in this docket. These amounts are not opposed by any party. The Commission has carefully reviewed these amounts and concludes that they are reasonable and appropriate for use in this docket and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The support for this finding is contained in Paragraph 4(f) of the Stipulation. The Stipulating Parties agreed that the debt cost to be used in this proceeding, based on the Company's Petition to Amend Cardinal's Term Loan Agreement filed in Docket No. G-39, Sub 40, and approved by the Commission on May 5, 2017, is 4.27%. No party objects to the debt cost. The Commission has carefully reviewed the debt cost and concludes that it is just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is contained in Cardinal's verified Application, the testimony and exhibits of the Company's witnesses, and the Stipulation.

The rates reflected on Exhibit B of the Stipulation are the result of negotiations among all of the parties to this proceeding and are not opposed by any party. The Commission has carefully reviewed these rates and concludes that they are just and reasonable and appropriate for all customer classes for use in this docket and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-17

These findings are supported in Paragraph 3 and Exhibits A and B of the Stipulation. The Stipulating Parties agreed to the allocation methodology employed by the Company in determining the cost of service applicable to each zone as shown on Exhibit A and the specific rates as shown on Exhibit B. The Stipulating Parties also agreed to the zonal allocation factors shown on Exhibit A of the Stipulation, which are the result of negotiations among the parties. No party opposes these findings. The Commission has carefully reviewed these amounts and concludes that they are just and reasonable and appropriate for use in this docket and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The support for this finding is contained in Paragraph 5 of the Stipulation. The Stipulating Parties agreed to an EDIT amortization adjustment, as set forth in Paragraph 5 of the Stipulation, which includes amortizing the EDIT associated with the Company's North Carolina corporate income tax changes over a 5-year period.

No party objects to this proposal. The Commission has carefully reviewed this proposal and concludes that it is just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The support for this finding is contained in Paragraph 7 of the Stipulation. The Stipulating Parties agreed to the Company's use of an AFUDC rate of 7.17%, effective with the date of the rates approved in this proceeding. No party objects to this proposal. The Commission has carefully reviewed this proposal and concludes that it is just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The support for this finding of fact is contained in Paragraph 8 of the Stipulation. The Stipulating Parties agree to Cardinal's request to defer certain pipeline integrity O&M expenses. The Stipulating Parties also agree that: Cardinal should be allowed to defer pipeline assessment costs for amounts paid for services provided by independent contractors and outside consultants that are necessary for compliance with the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations and to ensure the safety and integrity of the Cardinal pipeline. Further, the Stipulating Parties agree that authorization to defer the pipeline integrity costs will remain in effect through the effective date of rates in Cardinal's next general rate case, and that, consistent with prior Commission orders, Cardinal will not defer internal payroll costs or other internal O&M expenses. No party objects to Cardinal's request for deferral of its pipeline integrity O&M expenses and the future treatment of these expenses in the manner proposed in the Stipulation. The Commission has carefully reviewed the Company's request for deferral of certain pipeline integrity O&M expenses, and concludes that the proposal is reasonable and appropriate and should be approved and implemented as described in Paragraph 8 of the Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

Consistent with Paragraph 9 of the Stipulation, Cardinal agrees to file its next general rate case no later than March 15, 2022. Cardinal also agrees to provide the Public Staff, PSNC and Piedmont, one month prior to the filing date, a rough outline of the rate case, including the period selected as the test year for the rate case. Consistent with the Stipulation, the Stipulating Parties agree not to initiate a show cause proceeding relating to Cardinal's rates and charges before its next general rate case filing. The Stipulating Parties further agree, however, that they are not constrained in any way in their ability to seek changes to or make filings with the Commission, including complaint proceedings, regarding Cardinal's terms and conditions of service or operating practices as a consequence of the foregoing show cause moratorium. These findings are not contested by any party.

The Commission has carefully reviewed this proposal and concludes that it is just and reasonable in this docket and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

For the reasons set forth in the foregoing paragraphs, the Commission concludes that the Stipulation provides a just and reasonable resolution of all the issues in this case, will allow Cardinal an opportunity to recover its reasonable operating expenses and earn a fair return on its rate base under prudent management, and provides just and reasonable rates to all customer classes. Therefore, the Commission finds and concludes that all of the provisions of the Stipulation, taken together, are just and reasonable under the circumstances of this proceeding and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation is incorporated by reference herein and hereby approved in its entirety.

2. That Cardinal is hereby authorized to adjust its rates and charges in accordance with Exhibit B of the Stipulation, effective for service rendered on and after the first day of the first month following the date of this order.

3. That Cardinal shall file rates to comply with ordering Paragraph No. 1 of this order within ten (10) days from the date of this order.

4. That the rates contained in the Depreciation Rates Study filed by Cardinal on October 28, 2016, in Docket No. G-39, Sub 37, are approved.

5. That Cardinal shall file its next general rate case no later than March 15, 2022, and shall also provide the Public Staff, PSNC and Piedmont with a rough outline of the rate case, including the period selected as the test year for the rate case, one month prior to the filing date.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of July, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

DOCKET NO. G-40, SUB 135

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Frontier Natural Gas Company, LLC, for Annual Review of Gas Costs Pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6)	))))	ORDER ON ANNUAL REVIEW OF GAS COSTS

HEARD: Tuesday, March 7, 2017, at 10:00 a.m., in the Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; and Commissioners James G. Patterson and Lyons Gray

APPEARANCES:

For Frontier Natural Gas Company:

Karen M. Kemerait, Smith Moore Leatherwood LLP, 434 Fayetteville Street, Suite 2800, Raleigh, North Carolina 27601

For the Using and Consuming Public:

Elizabeth D. Culpepper, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: On December 1, 2016, pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), Frontier Natural Gas Company (Frontier or Company) filed the joint direct testimony and exhibits of Fred A. Steele, President/General Manager, in connection with the annual review of Frontier's gas costs for the twelve-month period ended September 30, 2016.

On December 7, 2016, the Commission issued Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice. The Order set the annual review of the Company's gas costs for hearing on March 7, 2017, set pre-filed testimony dates, and required Frontier to give notice of the hearing.

On January 11, 2017, Frontier filed the information required by the Commission's Order Requiring Reporting issued June 28, 2013, in Docket No. G-100, Sub 91 (G-100, Sub 91 Order), as a supplement to witness Steele's pre-filed direct testimony (Supplemental Information).

On February 7, 2017, Frontier filed its Affidavits of Publication of Public Notice of Hearing.

On February 20, 2017, the Public Staff – North Carolina Utilities Commission (Public Staff) filed the direct testimony of Julie G. Perry, Accounting Manager, Natural Gas Section, Accounting Division, and Jan A. Larsen, Director, Natural Gas Division.

On February 28, 2017, Frontier and the Public Staff filed a joint motion for witnesses to be excused from appearance at the hearing and requested that the pre-filed testimony and exhibits of all witnesses be received into the record without requiring the appearance of any such witnesses.

On March 2, 2017, the Commission issued an Order granting the motion in part by excusing the Public Staff's witnesses from attending the hearing and accepting their testimony into the record at the hearing. However, the Commission denied the motion as to Frontier witness Steele and required witness Steele to attend the hearing and respond to questions by the Commission.

On March 7, 2017, the matter came on for hearing as scheduled. The testimony and exhibits of the Public Staff witnesses were admitted into evidence without objection. Company witness Steele appeared in person to testify at the hearing and his pre-filed testimony, exhibits, and Supplemental Information were admitted into evidence. There were no public witnesses present.

On March 21, 2017, the Commission issued a Notice of Due Date for Proposed Orders/Briefs. By orders issued April 18, 2017, and April 26, 2017, the Commission granted the Public Staff's motions to extend the filing date for briefs and proposed orders.

On May 2, 2017, the Joint Proposed Order of Frontier and the Public Staff was filed.

No other party intervened in this docket.

Based upon the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Frontier is a public utility as defined by G.S. 62-3(23), organized and existing under the laws of the State of North Carolina with its headquarters in Elkin, North Carolina.

2. Frontier is a natural gas local distribution company (LDC), primarily engaged in the business of purchasing, transporting, distributing, and selling natural gas to approximately 3,343 customers in North Carolina, as of September 30, 2016.

3. The Company has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of such statute and rule.

4. The review period in this proceeding is the twelve months ended September 30, 2016.

5. During the review period, Frontier incurred total gas costs of $5,242,869, comprised of pipeline demand charges of $738,694, gas supply costs of $3,987,768, and other gas costs of $516,407.

6. Frontier's filed Deferred Gas Cost Account at September 30, 2016, reflects a credit balance of $7,899 (owed from the Company to customers).

7. Frontier began prorating its Benchmark City Gate Delivered Gas Cost (Benchmark) in the calculation of its gas cost collections from customers in a manner consistent with how Frontier prorates customers' bills.

8. Frontier performed an annual computation in a low gas sales month to true-up its estimate of unbilled and lost and unaccounted for volumes.

9. Frontier worked with the Public Staff to develop a new reporting format for determining the gas cost collections in order to have more transparency with the calculation of billed and unbilled volumes and the rate changes in effect that may impact the deferred account.

10. Frontier's applicable interest rate on all amounts over or under-collected from customers is 7.68%, effective January 1, 2017, as reflected by the balance in the Company's Deferred Gas Cost Account, which is the net-of-tax overall rate of return approved by the Commission in its Order Approving Use of Natural Gas Bond Funds issued March 12, 2000, in Docket No. G-40, Sub 2, adjusted for any known corporate income tax rate changes.

11. Frontier should continue to closely monitor the unbilled and lost and unaccounted for volumes in order to avoid future deferred account issues.

12. Frontier properly accounted for its gas costs during the review period.

13. Frontier's hedging activities during the review period were reasonable and prudent.

14. During the review period, Frontier purchased all of its gas supply requirements from a full requirements gas supplier, with the exception of transportation imbalance cash-outs.

15. Frontier utilized pipeline capacity from Transcontinental Gas Pipe Line Company, LLC (Transco), and acquired additional year round pipeline capacity on Transco during this review period, as well as contracted for additional capacity subsequent to this review period.

16. Frontier has adopted a gas purchasing policy that it refers to as a "best evaluated cost" supply strategy.

17. The gas costs incurred by Frontier during the review period were prudently incurred.

18. Frontier should be permitted to recover 100% of its prudently incurred gas costs.

19. Frontier should not be required to implement a rate decrement in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

These findings are essentially informational, procedural, or jurisdictional and are based on evidence uncontested by any of the parties. The evidence supporting these findings is contained in the official files and records of the Commission, the testimony and exhibits of Company witness Steele, and the testimony of Public Staff witnesses Perry and Larsen.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

The evidence supporting these findings is contained in the testimony of Frontier witness Steele, the testimony of Public Staff witness Perry and Larsen, and the provisions of G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

G.S. 62-133.4 requires that each natural gas utility submit to the Commission information and data for an historical twelve-month review period concerning its actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(c) requires the filing of work papers, direct testimony, and exhibits supporting the information.

Frontier witness Steele testified that the Company is responsible for and has complied with reporting gas costs and deferred account activity to the Commission and the Public Staff on a monthly basis as required by Commission Rule R1-17(k). Public Staff witnesses Perry and Larsen both confirmed that the Public Staff reviewed the filings and monthly reports filed by Frontier. The Commission, therefore, concludes that Frontier has complied with all of the procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the review period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-12

The evidence supporting these findings of fact is contained in the testimony and exhibits of Frontier witness Steele and the testimony of Public Staff witnesses Perry and Larsen.

Company Schedule 1 reflected that Frontier's total gas costs for the review period were $5,242,869. Public Staff witness Perry testified that total gas costs were comprised of pipeline demand charges of $738,694, gas supply costs of $3,987,768, and other gas costs of $516,407.

Public Staff witnesses Perry and Larsen testified that the Public Staff reviewed the testimony and exhibits of Company witness Steele, the Company's monthly Deferred Gas Cost Account reports, monthly financial and operating reports, the gas supply and transportation contracts, the reports filed with the Commission in Docket No. G-100, Sub 24A, and the Company's responses to Public Staff data requests. The responses to the Public Staff data requests contained information related to Frontier's gas purchasing and hedging philosophies, key customer metrics, gas portfolio mixes, long-term contracts entered into for the purchase of additional pipeline capacity, and reconciliations of capacity versus commodity cost of gas charges.

Company witness Steele testified that Frontier's Deferred Gas Cost Account had a $7,899 credit balance, as shown on Company Schedule 8, owed by Frontier to ratepayers at September 30, 2016. Public Staff witness Perry testified that there was a $362,641 change in Frontier's Deferred Gas Cost Account filed balance compared to the prior review period's adjusted ending balance of $354,742, which was approved by the Commission's Order on Annual Review of Gas Costs issued August 23, 2016, in Docket No. G-40, Sub 130 (2015 Annual Review Order). This change consisted of a commodity gas cost true-up of ($268,271), commodity true-up adjustments of $1,766, transportation customer balancing true-up of ($108,546), a Transco refund of ($111), accrued interest of $12,529, and a rounding adjustment of ($8).

Public Staff witness Perry further testified regarding the status of Frontier's compliance with the Commission's 2015 Annual Review Order, which required Frontier to: (1) begin prorating its Benchmark in the calculation of its gas cost collections from customers in a manner consistent with how Frontier prorates customers' bills; (2) perform an annual computation in a low gas sales month, either June, July, or August, to true-up its estimate of unbilled and lost and unaccounted for volumes; and (3) work with the Public Staff to develop a new reporting format for determining the gas cost collections in order to improve transparency concerning the calculation of billed and unbilled volumes and the rate changes in effect that may impact the deferred account. Witness Perry testified that throughout the current review period the Public Staff and Frontier had been working together to determine the accurate reporting of Benchmark proration calculations and unbilled and lost and unaccounted for volumes. She testified that the Public Staff and Frontier had also worked to develop a reporting format for gas cost collections and the rate changes that impact the deferred account.

Public Staff witness Perry recommended in her testimony (1) that Frontier continue to closely monitor the unbilled and lost and unaccounted for volumes in order to avoid future deferred account issues, and (2) that, effective January 1, 2017, Frontier use the net-of-tax overall rate of return approved by the Commission in its Order Approving Use of Natural Gas Bond Funds issued March 12, 2000, in Docket No. G-40, Sub 2 (Order Approving Use of Natural Gas Bond Funds), adjusted for any known corporate income tax rate changes, as the applicable interest rate on all amounts over-collected or under-collected from customers reflected in its Deferred Gas Cost Account. She stated that this approach is consistent with the other North Carolina LDCs. Witness Perry further recommended that the method and procedures used by the Company for the accrual of interest on the Deferred Gas Cost Account remain unchanged. Public Staff witness Perry stated that Frontier agreed with this recommendation.

The Commission asked Company witness Steele if he agreed with Public Staff witness Perry's recommendation to use the net-of-tax overall rate of return that had been approved in the Order Approving Use of Natural Gas Bonds and witness Steele testified that he did. He further testified that the rate was 7.68%.

Based on the foregoing, the Commission concludes that Frontier has properly accounted for its gas costs incurred during the review period and that the Deferred Gas Cost Account balance is correct. The Commission further concludes that the Public Staff's recommendations are appropriate and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this finding of fact is contained in the testimony and exhibits of Company witness Steele and the testimony of Public Staff witness Perry.

Company witness Steele testified that the Company engaged in hedging activity during the review period. Frontier's Schedule 11 reflected that it hedged approximately 26% of its forecasted purchased gas volumes and 24% of its actual gas supply volumes during the review period.

Company witness Steele further testified that market pricing met the targeted reductions that Frontier looked for as part of the purchasing strategy, which helped Frontier reduce potential volatility and price risk for its customers.

Public Staff witness Perry testified that Frontier's hedging program is an integral part of an overall gas purchasing strategy that attempts to establish price stability, utilize cost efficient purchasing, and reduce the risk of price increases to customers. Witness Perry testified that Frontier uses a weighted average, three-part approach in purchasing its physical gas supplies: first-of-the-month baseload; hedging; and daily swing. Furthermore, Public Staff witness Perry stated that a core part of Frontier's strategy is to obtain reliability and price stability by fixing components of its gas costs, primarily commodity costs, through hedging.

Public Staff witness Perry further testified that the primary difference in Frontier's hedging approach compared to other LDCs is that Frontier uses physical hedges exclusively and does not use financial hedges, such as options, futures, or swaps, which are typically used by the other North Carolina LDCs. She stated that Frontier's gas supply portfolio includes the physical purchase of fixed price gas supplies for delivery at its city gate on a monthly basis.

Public Staff witness Perry further testified that she concluded from her analysis based on what was reasonably known or should have been known at the time the Company made its hedging decisions affecting the review period, as opposed to the outcome of those decisions, that the Company's hedging decisions were prudent.

Based on the foregoing, the Commission concludes that Frontier's hedging activities during the review period were reasonable and prudent.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-18

The evidence for these findings of fact is contained in the testimony of Company witness Steele and the testimony of Public Staff witnesses Larsen and Perry.

Company witness Steele testified that the Company's gas supply policy is best described as a "best evaluated costs" supply strategy. This strategy is based upon the following criteria: flexibility, security/creditworthiness, reliability of supply, the cost of the gas, and the quality of supplier customer service. Witness Steele stated that the primary criteria for the Company are flexibility, security/creditworthiness, and reliability of supply.

Company witness Steele stated that flexibility is required because of the daily changes in Frontier's market requirements caused by the unpredictable nature of weather, the production levels/operating schedules of Frontier's industrial customers, the industrial customers' option to switch to alternative fuels, and customer growth during the test period. He noted that while Frontier's gas supply agreements have different purchase commitments and swing capabilities (i.e., the ability to adjust purchase volumes within the contract volume), the gas supply portfolio as a whole must be capable of handling the seasonal, monthly, daily, and hourly changes in Frontier's market requirements.

Company witness Steele testified that Frontier understands the necessity of having security of supply to provide reliable and dependable natural gas service and has demonstrated its ability to do so. He stated that Frontier's gas supply strategy and its contracts implementing this strategy have allowed Frontier to accomplish this objective.

Company witness Steele testified that the Company continues to incorporate a three part pricing strategy to help establish price stability and reduce risk to customers: hedging, first of the month index purchases, and daily purchases. Frontier will adjust the weights of each component and incorporate the best pricing methodology to obtain the optimum opportunity in savings and price stability. Company witness Steele further stated that the Company's gas pricing strategy reduced the risk and volatility in commodity gas pricing while also providing flexibility to take advantage of competitive pricing opportunities that may occur.

Public Staff witness Larsen testified that during the review period Frontier experienced customer growth of 7.39%, which represents a decline over the prior year growth rate of 12.30%. Public Staff witness Larsen testified that Frontier acquired an additional 2,337 dekatherms (dts) per day of Transco year round pipeline capacity effective January 1, 2016, which results in a total pipeline capacity for Frontier of 5,950 dts per day for the current review period. Company witness Steele testified to the Company's continuing need – in light of the Company's customer growth and annual demand forecasts – to purchase additional Transco capacity. Company witness Steele further testified that while the Company had a daily reservation capacity of 5,950 dts per day at the beginning of the review period, it successfully bid and was awarded an additional 2,663 dts per day in August, 2016 that became effective in January, 2017, which is outside of this review period. Consequently, the Company's total year round pipeline capacity is 8,613 dts per day, effective January 2017.

Company witness Steele and Public Staff witness Perry testified that effective April 1, 2016, Frontier began purchasing all of its gas supply requirements, with the exception of transportation customer imbalance cash-outs, from UGI Energy Services, LLC (UGI). Witness Steele explained that Frontier selected UGI based on UGI's ability to satisfy the criteria of Frontier's gas supply policy. Witness Perry explained that BP Energy Corporation (BP Energy) had been the full requirements gas supplier for Frontier since November 1, 2014.

At the hearing, Company witness Steele was asked by the Commission about gas storage opportunities. Witness Steele responded that there are opportunities to bid upon storage as well as capacity on Transco and that obtaining storage would also mean that additional capacity would be required in order to move stored gas to the Company's city gate. Witness Steele also responded that such opportunities, often referred to as "off-system storage," would be much less expensive than developing on system storage.

Company witness Steele also responded to Commission questions regarding the role of Gas Natural, Inc. (GNI), Frontier's ultimate parent company, in determining Frontier's gas supply. Witness Steele stated that GNI holds "weekly risk calls" with its four divisions (Frontier, Montana, Ohio, and Maine) and each division presents gas supply opportunities to the Risk Committee for evaluation.

> As to how Frontier plans to meet future system demand, Public Staff witness Larsen testified that he recommended Frontier have a study performed before the next annual review, similar to that attached to Company witness Steele's testimony as Exhibit FAS-1, discussing, among other things, peak day forecasts and determination of contract demand policy. Witness Larsen recommended that this study be made available to the Public Staff to review. In response to Commission questions regarding Public Staff witness Larsen's recommendation, Company witness Steele indicated that Frontier will internally prepare a study to meet the Public Staff's recommendation. He testified that Frontier would present its internal study to the Public Staff to "see if that will fulfill that recommendation." He added, "And then if it does not, we can certainly reach out and have another study done by somebody such as Kan Huston."

Based upon the Public Staff's investigation and review of the data filed in this docket, witness Larsen testified that Frontier's gas costs during the review period were prudently incurred.

Based on the foregoing, the Commission concludes that the Company's gas costs incurred during the review period were reasonable and prudently incurred and that the Company should be permitted to recover all of its prudently incurred gas costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence for this finding of fact is contained in the testimony and exhibits of Company witness Steele and the testimony of Public Staff witnesses Perry and Larsen.

Company witness Steele testified that Frontier strategically tries to minimize adjustments in pricing, which results in some fluctuations of the deferred account over the course of the year as the cost of gas changes. Company witness Steele also testified that Frontier had filed to decrease its Benchmark on two separate occasions during the review period: from $5.900/dt to $4.500/dt (Docket No. G-40, Sub 131), effective February 1, 2016; and from $4.500/dt to $3.500/dt (Docket No. G-40, Sub 134), effective August 1, 2016. Company witness Steele stated that those measures have allowed Frontier to recover its gas costs and reduce its Benchmark to more closely track the current NYMEX market price of gas. He further testified that although the Company had over-collected its gas costs as of September 30, 2016, the Company anticipated that the current credit balance would reverse over the near term.

Public Staff witness Perry agreed with Frontier's credit deferred account balance of $7,899, owed by the Company to the customers, as of September 30, 2016. Public Staff witness Larsen testified that he strongly recommended that Frontier closely monitor the deferred gas cost account balance in order to avoid high balances either owed to the Company or to the customers in the future, and, if needed, Frontier should request Commission approval for the implementation of a new temporary increment or decrement through its purchased gas adjustment (PGA) mechanism, which provides procedures for Frontier to file to adjust its rates pursuant to G.S. 62-133.4. Public Staff witness Larsen testified that he believed the Company is actively managing its deferred account via the PGA procedure, and did not recommend any temporary rate increments or decrements be implemented at this time.

The Commission agrees with the recommendation of Public Staff witness Larsen and concludes that it is not appropriate to require Frontier to implement any temporary rate increments or decrements at this time. In addition, the Commission concludes that, if needed, Frontier should manage its deferred account balances at any point during future review periods by requesting Commission approval to implement new temporary increments or decrements through the PGA procedures that are available for use by the Company

IT IS, THEREFORE, ORDERED as follows:

1. That Frontier's accounting for gas costs during the twelve month period ended September 30, 2016, is approved;

2. That the gas costs incurred by Frontier during the twelve-month period ended September 30, 2016, were reasonably and prudently incurred, and Frontier is hereby authorized to recover all of its gas costs incurred during the period of review;

3. That Frontier shall use the net-of-tax overall rate of return of 7.68% as the applicable interest rate on all amounts over-collected or under-collected from customers reflected in its Deferred Gas Cost Account effective January 1, 2017;

4. That Frontier shall continue to closely monitor the unbilled and lost and unaccounted for volumes in order to avoid future deferred account issues;

5. That Frontier shall continue to closely monitor the deferred gas cost account balance in order to avoid high balances either owed to the Company or to the ratepayers in the future; and

6. That before the filing of Frontier's next annual review proceeding, Frontier shall have a study performed, similar to the consultant report attached to Company witness Steele's testimony as Exhibit FAS-1, discussing, among other things, peak day forecasts and determination of contract demand policy, and made available to the Public Staff for its review;

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of June, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

NATURAL GAS – SHOW CAUSE

DOCKET NO. G-40, SUB 142

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Frontier Natural Gas Company – Violations of	)	ORDER APPROVING AGREEMENT
Title 49, Part 192, Subpart O, Code of Federal	)	AND STIPULATION OF SETTLEMENT
Regulations	)	

BY THE COMMISSION: On July 14, 2017, the North Carolina Utilities Commission (Commission) issued an Order Scheduling Show Cause Hearing in Docket No.G-40, Sub 142. The Order, among other things, required the Staff to file direct testimony on or before September 5, 2017, required Frontier Natural Gas Company (Frontier) and any intervenors in the docket to file testimony on or before September 25, 2017, and scheduled a hearing in this matter for October 16, 2017.

On August 25, 2017, the Staff filed the joint direct testimony and exhibits of John S. Hall, Harry C. Bryant, Ill and Stephen P. Wood. On October 4, 2017, after obtaining two extensions of time, Frontier filed direct testimony and exhibits of Fred A Steele, direct testimony and exhibit of Narinder (Mickey) Grewal, and direct testimony of Rodney Myers.

On October 12, 2017, Frontier filed an Agreement and Stipulation of Settlement and Supplemental Testimony of Stephen P. Wood in support of the Settlement Agreement. In summary, the Agreement and Stipulation of Settlement requires the following:

1- Prior to September 1, 2018, Frontier will have at least a representative portion of its transmission system inspected by an advanced in-line inspection tool known as a "smart pig."

2- Prior to July 1, 2018, Frontier will conduct an emergency response simulation exercise that follows the protocol for addressing a non-weather related breach in the portion of pipeline near Transco's take-off during peak periods.

3- Frontier will comply with all reporting requirements as specified in the schedule attached as Exhibit A to the Agreement.

4- In addition to the costs incurred above, Frontier will expend an additional $2 to $3 million in identifying and implementing system changes to enhance Frontier's system reliability and public safety in case of a pipeline breach. Frontier will engage with Commission Staff in a cooperative information-sharing process prior to and throughout implementation and shall file a report after completion of system enhancements.

5- Frontier will pay a civil penalty of $200,000.

On October 12, 2017, Frontier Natural Gas Company also filed a motion requesting that their witnesses be excused from attending the evidentiary hearing on October 16, 2017. Frontier stated that counsel for Frontier had consulted with the Commission Staff who agreed to waive cross-examination of all witnesses and offer no objection to the introduction of Frontier's affidavits, testimony, work papers, and exhibits into the record. On October 13, 2017, the Commission issued an Order Granting Motion to Excuse Witnesses and Canceling Hearing.

Upon consideration of the entire record in this proceeding, the Commission finds and concludes that the Agreement and Stipulation of Settlement dated October 12, 2017, which is incorporated herein by reference and attached hereto, is in the public interest and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the October 12, 2017 Agreement and Stipulation of Settlement filed with the Commission is hereby approved.

2. That approval of this Agreement and Stipulation of Settlement resolves the show cause proceeding which is hereby dismissed.

3. With respect to Section 2.A. of Agreement, the determination of what is the representative portion of Frontier's transmission system to be inspected by a "smart pig" shall be made in consultation and coordination with Commission Staff and the Commission shall resolve any dispute, if any, regarding what constitutes a representative portion of the transmission system.

4. Frontier shall pay the civil penalty of Two Hundred Thousand Dollars ($200,000) on or before December 31, 2017.

5. That the Commission shall retain jurisdiction over this matter to oversee and enforce the implementation of the Agreement and Stipulation of Settlement and to issue additional orders as it deems necessary.

ISSUED BY ORDER OF THE COMMISSION.
This the __31st___ day of October, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. G-40, SUB 142

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Frontier Natural Gas Company – Violations of Title 49, Part 192, Subpart O, Code of Federal Regulations	)))	AGREEMENT AND STIPULATION OF SETTLEMENT

This Settlement Agreement is entered by and between Frontier Natural Gas Company (Frontier), and the Pipeline Safety Section of the Operations Division, North Carolina Utilities Commission (Staff) (collectively, Stipulating Parties).

WHEREAS, Frontier is a natural gas local distribution company regulated pursuant to Chapter 62 of the North Carolina General Statutes and subject to the requirements of Subpart O of the provisions of Title 49, Part 192, Code of Federal Regulations (Integrity Management Regulations); and

WHEREAS, Frontier is the subject of the pending show cause proceeding in the above-captioned docket for alleged failures to comply with certain provisions of the Integrity Management Regulations; and

WHEREAS, the Stipulating Parties are the only parties of record in this docket; and

WHEREAS, after extensive discussions, the Stipulating Parties have reached a Settlement Agreement (Settlement), the terms and conditions of which are set forth below, that resolves all issues and claims in this docket; and

WHEREAS, the Stipulating Parties believe that the terms and conditions of the Settlement serve the interests of Frontier's customers and the public.

NOW, THEREFORE, the undersigned Stipulating Parties, in consideration of the premises and in settlement and compromise of their respective litigation positions in this proceeding, do hereby agree to a settlement of the disputes between them in this docket.

I. BACKGROUND

On July 14, 2017, the North Carolina Utilities Commission (Commission) issued an Order Scheduling Show Cause Hearing in Docket No.G-40, Sub 142. The Order, among other things, required the Staff to file direct testimony on or before September 5, 2017, required Frontier and any intervenors in the docket to file testimony on or before September 25, 2017, and scheduled a hearing in this matter for October 16, 2017.

On August 25, 2017, the Staff filed the joint direct testimony and exhibits of John S. Hall, Harry C. Bryant, III and Stephen P. Wood.

On October 4, 2017, after obtaining two extensions of time, Frontier filed direct testimony and exhibits of Fred A. Steele, direct testimony and exhibit of Narinder (Mickey) Grewal, and direct testimony of Rodney Myers.

II. TERMS OF AGREEMENT

1. The intent of this Settlement Agreement is to resolve all issues between Frontier and the Staff in Docket No. G-40, Sub 142 relating to Frontier's compliance with federal Integrity Management Regulations and a penalty for prior non-compliance with such regulations.

2. This Settlement Agreement consists of the following material agreements of the Stipulating Parties with respect to the outstanding issues in this proceeding:

A. Prior to September 1, 2018, or as soon as practicable based on contractor availability and acquisition of necessary property rights, Frontier will have at least a representative portion of its transmission system inspected by means of an advanced in-line inspection tool, commonly known as a "smart pig."

B. Prior to July 1, 2018, with the assistance of an outside consultant, Frontier will conduct an emergency response simulation exercise that follows the protocol for addressing a non-weather related breach in a portion of Frontier's transmission pipeline, near the Transco take-off, during a period of peak, heat-sensitive demand.

C. Frontier will complete all of the work and will comply with the reporting requirements as specified in the schedule attached hereto as Exhibit A and incorporated by reference herein.

D. In addition to the amounts expended to comply with points A. through C. above, Frontier will expend up to the amount of \$2.0 to \$3.0 million in identifying and implementing system changes to enhance Frontier's system reliability and public safety in the case of a pipeline breach under peak day or near peak day conditions. Frontier will engage in a cooperative process with the Commission Staff for the purpose of meeting this requirement. The parameters of this process shall include:

(i) A meeting between Staff and Frontier, to be held within sixty (60) days after approval of this Settlement by the Commission, in which Staff and Frontier will discuss ideas, issues, and concerns related to the potential enhancement of Frontier's system as contemplated by this Section 2.D. To the extent workable, the Stipulating Parties will align the time table for this cooperative process with the time table for Frontier's compliance with Regulatory Condition No.

14 of the Commission's Order Approving Merger Subject to Regulatory Conditions (Merger Order), Docket No. G-40, Sub 136 (August 1, 2017).

(ii) The evaluation and identification by Frontier of possible measures to achieve the desired enhancements to system reliability and safety under the conditions described above.

(iii) The submission to Staff of specific measures proposed by Frontier to achieve the goals cited above no later than 180 days after completion of the emergency response simulation exercise provided for in Section 2.B. above, along with the projected costs for the construction/implementation of such measures and a proposed timeline for such construction/implementation.

(iv) Discussions with Staff regarding the proposed measures. Further, Frontier hereby commits to seriously consider any input from Staff regarding those measures.

(v) The $2.0 to $3.0 million expended pursuant to this provision will be consistent with sound engineering practices and the efficient enhancement of Frontier's system reliability and safety, it being the parties' intention that measures to enhance system reliability and safety be rational, cost-effective, and sound from an engineering perspective. In the event of any dispute regarding whether Frontier has complied with this provision, which the Stipulating Parties are unable to resolve between themselves, the dispute shall be submitted to the Commission for resolution prior to the construction of any improvements.

(vi) Pipeline looping shall not be included in the measures utilized to enhance system reliability or safety unless specifically agreed to by the Stipulating Parties. Expenditures under this provision shall also not be used for the purpose of achieving IMP compliance unless such compliance is an ancillary effect of the system enhancement and Staff specifically agrees that such expenditures shall qualify under this provision.

(vii) Frontier will file, within three (3) months after completion of construction of the system enhancements contemplated above, a report in Docket No. G-40, Sub 142 providing the details of the work completed and an itemized accounting of all monies spent on such work.

E. Frontier will pay a civil penalty of Two Hundred Thousand Dollars ($200,000).

3. The Stipulating Parties agree to support this settlement in the evidence and proposed orders they submit to the Commission in this proceeding, to waive cross-examination of each other's witnesses, and to stipulate that all pre-filed testimony and exhibits of the Stipulating Parties may be received into evidence.

4. This Settlement Agreement is the product of give-and-take negotiations, and no portion of this Agreement shall be binding on the Stipulating Parties unless the entire Agreement is accepted by the Commission.

5. This Settlement Agreement shall be effective upon execution by the Stipulating Parties and shall be interpreted according to North Carolina law.

Agreed and stipulated to this the 12TH day of October, 2017.

Frontier Natural Gas Company

By: ______________________

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North Carolina Utilities Commission Staff

By: Leonard G. Green

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Section 1 - Scope of Work

2017 Work

1.1 Frontier and its present engineering consultant, AECOM, or other engineering consultant, will develop a scope of work as to review, critique and to recommend best practices specific to Frontier's Integrity Management Program (IMP) by October 15, 2017.

1.1.1 The above scope of work will include a recommendation from AECOM as to the how to proceed with performing the required ICDA's in the current IMP for Greenway and West Park. The final report from AECOM would be completed by December 2017. To minimize the risk of customer impact due to reduced capacity, ICDA work will be conducted after March 20, 2018 but before October 31, 2018 pending contractor availability and the acquisition of land rights for the required workspace. Frontier and AECOM will meet in January 2018 and present the report and its findings to the North Carolina Utilities Commission Staff. Frontier will also have a 5-year capital budget for all IMP required system modifications and remediation, as applicable.

1.2 Perform direct assessment on T-3 and T-7 as recommended in the EN Engineering Indirect Inspection report, due October 30, 2017, subject to Permit and Scheduling. Final report inclusive of Direct Examination and Post Assessment will be due by March 31, 2018. Any anomalies, if discovered, will be remediated consistent with 49 CFR Part 192.

1.3 Award the contract for the ECDA's on T-2, T-8, T-10, T-12 and T-13 by September 30, 2017.

1.4 Initiate the early sending of the RFP to engineering firms for proposals for the ECDA on T-1 by December 2017.

1.5. Perform direct assessment on T-2, T-8, T-10, T-12 and T-13 as recommended in the EN Engineering Indirect Inspection Report, due December 15, 2017, subject to Permit and Scheduling. Final report inclusive of Direct Examination and Post Assessment will be due by March 31, 2018. Any anomalies, if discovered, will be remediated consistent with 49 CFR Part 192.

2018 Work

1.6 Final reports on all direct assessments will be due by March 31, 2018, subject to Permit and Scheduling. Any anomalies, if discovered, will be remediated consistent with 49 CFR Part 192.

1.7 Complete reassessment ECDA Indirect surveys on T-1 by March 30, 2018. Final report will be due by June 30, 2018 subject to Permit and Scheduling. Any anomalies, if discovered, will be remediated consistent with 49 CFR Part 192.

Risk and Mitigation

This is a single feed system. Meeting schedule deadlines are highly dependent on qualified assessment contractor availability, acquisition of required land rights, permitting by governmental and regulatory authorities and other factors outside of the control of Frontier and AECOM. Impacts of schedule delays outside of the control of Frontier and AECOM will be mitigated by beginning work on these items immediately.

Section 2 - Required Continuous Reporting

2.1 Frontier agrees to submit a monthly progress report to the North Carolina Utilities Commission Staff on or before the 10th day each month beginning with September 2017 until all work in Section 1 above is completed.

2.2 AECOM will monitor and audit the monthly progress report to the North Carolina Utilities Commission Staff and report any deviation(s) from the schedule outlined in Section 1 above.

2.3 The North Carolina Utilities Commission Staff reserves the right to initiate a Show Cause hearing if it believes that Frontier is not proceeding in completing the Scope of Work as outlined in Section 1 above in the timeline submitted.

NORTH CAROLINA UTILITIES COMMISSION
Pipeline Safety Section
4325 Mail Service Center
Raleigh, NC 27699-4300

October 12, 2017

Via electronic mail

North Carolina Utilities Commission
Attn: Ms. M. Lynn Jarvis, Chief Clerk
430 N. Salisbury Street
Raleigh, North Carolina 27601

Re: Settlement Agreement in Frontier Show Cause, Docket No. G-40, Sub 142

Dear Ms. Jarvis:

Please find attached for filing in Docket No. G-40, Sub 142 the following two documents:

1. Agreement and Stipulation of Settlement; and
2. Commission Pipeline Safety Section Supplemental Testimony of Stephen P. Wood in Support of Settlement Agreement.

Thank you for your assistance.

Yours truly,

Leonard G. Green
Senior Staff Attorney
NC Utilities Commission
lgreen@ncuc.net
(919) 733-0834

cc: Mr. Bill Gilmore
Mr. James H. Jeffries, IV

DOCKET NO. SC-1342, SUB 1
DOCKET NO. SC-1802, SUB 2
DOCKET NO. P-747, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request by Global Tel*Link Corporation	)	
and its Subsidiaries, for Waiver of	)	ORDER GRANTING REQUEST
Rule R13-9(d) of the Rules and Regulations	)	FOR WAIVER OF COMMISSION
of the North Carolina Utilities Commission	)	RULE R13-9(d)

BY THE COMMISSION: On May 4, 2017, Global Tel*Link (GTL or Petitioner) and its subsidiaries, Public Communications Services, Inc. and Value Added Communications, Inc. filed a Verified Petition for Waiver of Rule (Verified Petition) of Commission Rule R13-9(d). In the Verified Petition, GTL stated that its petition is similar to petitions filed by inmate calling service (ICS) providers Securus Technologies, Inc. on August 30, 2016 and Pay Tel Communications, Inc., on December 1, 2016, respectively, that, in response to those petitions, the Commission issued an order granting Securus' waiver request on January 11, 2017 and Pay Tel's waiver request on January 25, 2017, that each of the waivers was based on North Carolina specific data provided by Securus and Pay Tel and that, in individual orders, the Commission authorized, Securus and Pay Tel to charge a cap or maximum per minute calling rate of $0.24 for local automated collect station-to-station calls in North Carolina.

Further, the Petitioner stated that GTL and its subsidiaries are ICS providers and that it/they provides inmate calling services and related services to confinement facilities in forty-nine (49) states, including North Carolina, the District of Columbia and Puerto Rico, that Commission Rule R13-9(d) states:

> (d) *0 + Local Automated Collect Station-to-Station.* The recipient of a local automated collect station-to-station call may not be charged more for the call than would have been charged by Windstream Concord Telephone, Inc. for a local collect station-to-station call.,

that, pursuant to Commission Rule R13-9(d), Petitioner and its subsidiaries are authorized to charge and are charging a maximum of $1.71[1] per local, automated collect station-to-station call, that the Federal Communications Commission's Order addressing Rates for Interstate Inmate Calling Services, Second Report and Order and Third Further Notice of Proposed Rulemaking, 30 FCC Rcd 12763 (2015)(the FCC ICS Order) prohibits per call flat rates, that the Petitioner and its subsidiaries have adjusted their billing practices to comply with the ICS Order, that the rate that

[1] In Docket No. P-100, Sub 84c, Commission Rule R13-9(d) was revised by the May 1, 2008 Order Revising Rule R13-9(d) to reflect its current terms and to establish the per call rate cap for 0+ local automated collect station-to-station calls of $1.71.

Petitioner and its subsidiaries are allowed to charge under Commission Rule R13-9(d) does not reflect or recover GTL's and its subsidiaries' cost of service in North Carolina when the per call cap is converted into a per minute rate, and that the Commission should restructure the rate that the Petitioner and its subsidiaries are authorized to charge by Commission Rule R13-9(d) to allow it and its subsidiaries to collect a maximum "per minute" calling rate of $0.24 for 0+ local automated collect station-to-station calls in North Carolina.

The Petitioner thereafter requested that the Commission issue an order: (a) waiving the requirements of Commission Rule R13-9(d) as applied to Petitioner and its subsidiaries, (b) approving Petitioner's proposal to implement a cap or maximum calling rate of $0.24 per minute for local automated collect station-to-station calls in North Carolina, and (c) approving Petitioner's proposal that the maximum calling rate of $0.24 "per minute" become effective not later than 30 days from the filing date of the Verified Petition.

On May 11, 2017, the Commission issued an Order Requesting Comments requiring the Public Staff and other interested parties to file comments by no later than May 24, 2017 and the Company to file reply comments by May 31, 2017.

On May 24, 2017, the Public Staff filed a Motion Requesting an Extension of Time. On May 25, 2017, the Commission issued its Order granting all interested parties an additional 14 days to file comments and the Company an additional 14 days to file reply comments, the Chairman, finds that good cause exists to grant the motion.

On June 6, 2017, the Public Staff filed Public Staff Comments (Comments). In its Comments, the Public Staff stated that it had reviewed the Verified Petition and cost study filed by the Company and that it agrees that the requirements of Commission Rule R13-9(d) as applied to the Petitioner should be waived. Further, the Public Staff stated that the rate that the Petitioner is authorized to charge should be subject to the cap or maximum "per minute" calling rate of $0.24 for 0+ local automated collect station-to-station calls in North Carolina and that such rate is just and reasonable.

As of the date of this Order, no other interested party has filed comments and the Petitioner has not filed Reply Comments.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After carefully considering the Verified Petition, the Comments of the Public Staff and the record proper, the Commission finds and so concludes that the rate that GTL and its subsidiaries, Public Communications Services, Inc. and Value Added Communications, Inc. are authorized to charge for local automated collect station-to-station calls in North Carolina should be subject to a cap or maximum per minute calling rate of $0.24, that the cap or maximum per minute calling rate of $0.24 is just and reasonable, that the request that the Commission waive the provisions of Commission Rule R13-9(d) as it applies to GTL and its subsidiaries should be granted, and that the new rate should be allowed to become effective as of October 1, 2017.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of October, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. SC-62, SUB 5

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request by Pay Tel Communications, Inc.,	)	
for Waiver of Rule R13-9(d) of the Rules and	)	ORDER APPROVING STIPULATION
Regulations of the North Carolina Utilities	)	AND GRANTING WAIVER
Commission	)	

BY THE COMMISSION: On December 1, 2016, Pay Tel Communications, Inc. (Pay Tel or Petitioner) filed a Verified Petition for Waiver of Rule R13-9(d) of the Rules and Regulations of the North Carolina Utilities Commission (Verified Petition). Commission Rule R13-9(d) provides:

> (d) *0 + Local Automated Collect Station-to-Station.* The recipient of a local automated collect station-to-station call may not be charged more for the call than would have been charged by Windstream Concord Telephone, Inc. for a local collect station-to-station call.

In the Verified Petition, Pay Tel stated that it provides inmate calling services (ICS) and related technologies to jails in 14 states, including North Carolina, that, pursuant to Commission Rule R13-9(d), Petitioner is authorized to charge a maximum of $1.71[1] per local, automated collect station-to-station call, that the rate that Petitioner is allowed to charge under Commission Rule R13-9(d) does not reflect the Petitioner's cost of service, and that the Federal Communications Commission's Order addressing Rates for Interstate Inmate Calling Services, Second Report and Order and Third Further Notice of Proposed Rulemaking, 30 FCC Rcd 12763 (2015)(the FCC's 2015 ICS Order) combined with North Carolina's cap on local rates has had a detrimental impact on Petitioner's ability to earn fair compensation for the provision of inmate calling services in

[1] In Docket No. P-100, Sub 84c, Commission Rule R13-9(d) was revised by the May 1, 2008 Order Revising Rule R13-9(d) to reflect its current terms and to establish the per call rate cap for 0+ local automated collect station-to-station calls of $1.71.

North Carolina. Further, the Petitioner stated that the FCC's 2015 ICS Order prohibits per call surcharges and per call flat rates, and that the Commission should restructure the rate that the Petitioner is authorized to charge by Commission Rule R13-9(d) to allow it to collect a maximum "per minute" calling rate of $0.28 for 0+ local automated collect station-to-station calls in North Carolina.

Pay Tel thereafter requested that the Commission issue an order: (a) waiving the requirements of Commission Rule R13-9(d) as applied to Petitioner, (b) approving Petitioner's proposal to implement a cap or maximum calling rate of $0.28 per minute for local automated collect station-to-station calls in North Carolina, and (c) approving Petitioner's proposal that the maximum calling rate of $0.28 "per minute" become effective not later than 30 days from the filing date of the Verified Petition.

On December 2, 2016, the Commission issued an Order Requesting Comments from all parties that participated in Docket P-100 Sub 84 as well the Attorney General, the Public Staff-North Carolina Utilities Commission (the Public Staff) and North Carolina Prisoner Legal Services (NCPLS). Initial comments were required to be filed by January 13, 2017 and reply comments were required to be filed by January 27, 2017.

On December 20, 2016, Pay Tel and the Public Staff (collectively the Stipulating Parties or Parties and individually Party), pursuant to G.S. 62-69 and Rule R1-24(c) of the Rules and Regulations of the North Carolina Utilities Commission filed a Stipulation.

In the Stipulation, the Stipulating Parties agreed to the following:

1. In North Carolina, Pay Tel is authorized to provide telephone service via pay telephone instruments, including the provision of automated collect telephone service pursuant to PSP Certificate 62A as granted by the Commission on April 8, 1994, in Docket No. SC-62, Sub 3.

2. Pay Tel provides inmate calling services to jails in 14 states, including North Carolina.

3. Pay Tel has asked for a waiver of Commission Rule R13-9(d) which provides that the recipient of local automated collect station-to-station call may not be charged more than it would have been charged by Windstream Concord Telephone, Inc.[1] (Windstream Concord) for a local collect station-to-station call. This equates to a maximum rate of $1.71 per call based on Windstream Concord's current rate.

4. In 2008, the Commission established the current maximum rate of $1.71 per call based upon the rate approved for Windstream Concord. In the 2008 proceeding, the Public Staff noted that the maximum rate adopted is a surrogate rate for ICS providers.

[1] Windstream Concord is now known as Windstream Concord Telephone, LLC.

5. Pay Tel is seeking relief due to the impact of the FCC's 2015 ICS Order. This Order, among other reforms, imposes rate caps for intrastate ICS call rates and eliminated or reduced numerous ancillary service charges. According to Pay Tel, the impact of the reforms mandated by the FCC's 2015 ICS Order impairs its ability to earn fair compensation for the provision of ICS in North Carolina including the ability to recover its costs of providing local automated collect station-to-station calls.

6. Pay Tel requested a waiver of Rule R13-9(d) and proposed restructuring the rate it is authorized to charge to be subject to a cap or maximum per minute calling rate of $0.28 for 0+ local automated collect station-to-station calls in North Carolina. Pay Tel submitted a cost study in support of its requested cap or maximum rate of $0.28 per minute.

7. In consideration of the Verified Petition and the cost study filed by Pay Tel and the impact of the current FCC proceedings, the Stipulating Parties agreed that the requirements of Rule R13-9(d) as applied to Pay Tel should be waived; that the rate that Pay Tel is authorized to charge should be subject to a cap or maximum per minute calling rate of $0.24 for local automated collect station-to-station calls in North Carolina; and that such stipulated rate is just and reasonable.

8. The Stipulating Parties request that the Commission approve the Stipulation and enter an order in the docket which (a) grants Pay Tel a waiver of Rule R13-9(d) and (b) authorizes Pay Tel to implement a cap or maximum per minute calling rate of $0.24 for 0+ local automated collect station-to-station calls in North Carolina no later than February 1, 2017.

9. The Stipulation is the product of give-and-take negotiations, and no portion of the Stipulation shall be binding on the Stipulating Parties unless the entire Stipulation is accepted by the Commission.

As indicated above, all parties that participated in Docket P-100 Sub 84 as well the Attorney General, the Public Staff and NCPLS were notified by the December 2, 2016 Order Requesting Comments that that Pay Tel was requesting a waiver of Commission Rule R13-9(d) and that any initial comments that an interested party desired to make regarding Pay Tel's request were required to be filed with the Commission by January 13, 2017. As of this date, no comments have been filed in this docket.

On January 17, 2017, Pay Tel filed Reply Comments Supporting Petition for Waiver. In its Reply Comments, Pay Tel noted: (a) that no party had submitted comments responding to Pay Tel's Petition or to the Public Staff/Pay Tel Stipulation; and (b) that the Commission had issued an Order on January 11, 2017, in Docket SC-1427, Sub 9, granting Securus Technologies, Inc., the same relief sought by Pay Tel in the Public Staff/Pay Tel Stipulation. Pay Tel thereafter requested that the Commission accept and approve the Stipulation and grant it the relief requested in the Public Staff/PayTel Stipulation.

After careful consideration, the Commission, in its discretion, finds and concludes that good cause exists to accept and approve the Stipulation. Further, the Commission finds and so concludes that the Stipulation is the product of the give-and-take among the Stipulating Parties during their settlement negotiations, that the rate that Pay Tel is authorized to charge for local automated collect station-to-station calls in North Carolina should be subject to a cap or maximum per minute calling rate of $0.24, that such stipulated rate is just and reasonable, that Pay Tel's request that the Commission waive the provisions of Commission Rule R13-9(d) as it applies to Pay Tel should be granted, and that Pay Tel's new rate should be allowed to become effective as of February 1, 2017.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of January, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

DOCKET NO. SC-1427, SUB 9

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request by Securus Technologies, Inc.,	)	
for Waiver of Rule R13-9(d) of the Rules and	)	ORDER GRANTING REQUEST
Regulations of the North Carolina Utilities	)	FOR WAIVER OF COMMISSION
Commission	)	RULE R13-9(d)

BY THE COMMISSION: On August 30, 2016, Securus Technologies, Inc. (Securus or Petitioner) filed a Verified Petition for Waiver of Rule R13-9(d) of the Rules and Regulations of the North Carolina Utilities Commission (Verified Petition). In the Verified Petition, Securus requested that the Commission issue an order: (a) waiving the requirements of Commission Rule R13-9(d) as applied to Petitioner, (b) approving Petitioner's proposal to implement a cap or maximum calling rate of $0.28 per minute for local automated collect station-to-station calls in North Carolina, and (c) approving Petitioner's proposal that the maximum calling rate of $0.28 "per minute" become effective not later than 30 days from the filing date of the Verified Petition.

On September 8, 2016, the Commission issued its Order Requesting Comments from all parties that participated in Docket P-100 Sub 84(c) as well the Attorney General, the Public Staff-North Carolina Utilities Commission (the Public Staff) and North Carolina Prisoner Legal Services (NCPLS). Initial comments were required to be filed by October 19, 2016 and reply comments were required to be filed by November 2, 2016.

On September 27, 2016, the Public Staff filed a motion requesting that the Commission extend the time to file initial comments from October 19, 2016 to November 2, 2016 and reply comments from November 2, 2016 to November 16, 2016. On October 5, 2016, the Commission issued an Order granting the requested extension.

On November 2, 2016, the Public Staff filed a second motion requesting that the Commission extend the time to file initial comments from November 2, 2016 to November 16, 2016 and to file reply comments from November 16, 2016 to November 30, 2016. On November 15, 2016, the Commission issued an Order granting the requested extension.

On November 16, 2016, the Public Staff filed a third motion requesting that the Commission extend the time to file initial comments from November 16, 2016 to November 23, 2016 and to file reply comments from November 30, 2016 to December 7, 2016. On November 16, 2016, the Commission issued an Order granting the requested extension.

On November 23, 2016, Global Tel*Link Corporation (GTL) filed comments. Also, on that date, Securus and the Public Staff (collectively the Stipulating Parties or Parties and individually Party), pursuant to G.S. 62-69 and Rule R1-24(c) of the Rules and Regulations of the North Carolina Utilities Commission filed a Joint Stipulation in lieu of Comments.

On December 1, 2016, Securus filed its Reply Comments - Affidavit of Curtis L. Hopfinger and Response to Comments of GTL.

The various pleadings and filings made in this docket are summarized as follows:

The Verified Petition

In the Petition, Securus stated that it provides inmate calling services to 36 jails in North Carolina, that, pursuant to Commission Rule R13-9(d), Petitioner is authorized to charge and is charging a maximum of $1.71[1] per local, automated collect station-to-station call, that the rate that Petitioner is allowed to charge under Commission Rule R13-9(d) does not reflect the Petitioner's cost of service, and that the Federal Communications Commission's Order addressing Rates for Interstate Inmate Calling Services, Second Report and Order and Third Further Notice of Proposed Rulemaking, 30 FCC Rcd 12763 (2015)(the FCC 2015 ICS Order) has sharply impacted and further limited the Petitioner's ability to earn fair compensation for the provision of inmate calling services in North Carolina. Further, the Petitioner stated that the ICS Order prohibits per call flat rates, that the Petitioner has adjusted its billing practices to comply with the ICS Order and that the Commission should restructure the rate that the Petitioner is authorized to charge by Commission Rule R13-9(d) to allow it to collect a maximum "per minute" calling rate of $0.28 for 0+ local automated collect station-to-station calls in North Carolina.

Securus thereafter requested that the Commission issue an order: (a) waiving the requirements of Commission Rule R13-9(d) as applied to Petitioner, (b) approving Petitioner's

[1] In Docket No. P-100, Sub 84(c), Commission Rule R13-9(d) was revised by the May 1, 2008 Order Revising Rule R13-9(d) to reflect its current terms and to establish the per call rate cap for 0+ local automated collect station-to-station calls of $1.71.

proposal to implement a cap or maximum calling rate of $0.28 per minute for local automated collect station-to-station calls in North Carolina, and (c) approving Petitioner's proposal that the maximum calling rate of $0.28 "per minute" become effective not later than 30 days from the filing date of the Verified Petition. Additionally, Securus noted that it would file a separate confidential version of the Petition and its supporting cost study which would include sensitive, proprietary information. Securus subsequently filed a separate confidential version of the Verified Petition and its supporting cost study with the Commission.

GTL's Comments

In its comments, GTL supported Securus' request that the Commission waive the rate cap imposed by Commission Rule R13-9(d). GTL did not, however, support Securus' request that the waiver only be granted to Securus. According to GTL, it would be unfair for the Commission to waive the requirements of Commission Rule R13-9(d) only for Securus because ICS contracts are awarded based on competitive bidding process in which multiple ICS providers compete to serve a correctional facility based upon the specific request for proposal issued by a correctional facility. If Securus is the only ICS provider who is exempted from the requirements of Commission Rule R13-9(d), Securus would have a competitive advantage over other ICS providers in bidding for and negotiating contracts to serve correctional facilities because it would be able to utilize and apply the requested per minute rate while other ICS providers would be required to bid based on the rate cap required by Commission Rule R13-9(d). To put all ICS providers on the same competitive playing filed, GTL thus urged the Commission to grant all ICS providers operating in North Carolina the same relief that Securus is requesting with regard to the per minute rate cap and the requested waiver from Commission Rule R13-9(d).

The Joint Stipulation

In the Joint Stipulation, the Stipulating Parties agreed to the following:

1. In North Carolina, Securus is authorized to provide telephone service via pay telephone instruments, including the provision of automated collect telephone service pursuant to PSP Certificate 1396A as granted by the Commission on November 18, 2010, in Docket No. SC-1427, Sub 7.

2. Securus provides inmate calling services to public safety, law enforcement, and correction agencies throughout North America, including North Carolina.

3. Securus has asked for a waiver of Commission Rule R13-9(d) which provides that the recipient of local automated collect station-to-station call may not be charged more than it would have been charged by Windstream Concord Telephone, Inc.[1] (Windstream Concord) for a local collect station-to-station call. This equates to a maximum rate of $1.71 per call based on Windstream Concord's current rate.

[1] Windstream Concord is now known as Windstream Concord Telephone, LLC.

4. In 2008, the Commission established the current maximum rate of $1.71 per call based upon the rate approved for Windstream Concord. In the 2008 proceeding, the Public Staff noted that the maximum rate adopted is a surrogate rate for ICS providers.

5. Securus is seeking relief due to the impact of the FCC's 2015 ICS Order. This Order, among other reforms, imposes rate caps for intrastate ICS call rates and eliminated or reduced numerous ancillary service charges. According to Securus, the impact of the reforms mandated by the FCC 2015 ICS Order impairs its ability to earn fair compensation for the provision of ICS in North Carolina including the ability to recover its costs of providing local automated collect station-to-station calls.

6. Securus requested a waiver of Rule R13-9(d) and proposed restructuring the rate it is authorized to charge to be subject to a cap or maximum per minute calling rate of $0.28 for 0+ local automated collect station-to-station calls in North Carolina. Securus submitted a cost study in support of its requested cap or maximum rate of $0.28 per minute.

7. In consideration of the Verified Petition and the cost study filed by Securus and the impact of the current FCC proceedings, the Stipulating Parties agreed that the current requirements of Rule R13-9(d) as applied to Securus should be waived; that the rate that Securus is authorized to charge should be subject to a cap or maximum per minute calling rate of $0.24 for local automated collect station-to-station calls in North Carolina; and that such stipulated rate is just and reasonable.

8. The Stipulating Parties request that the Commission approve the Stipulation and enter an order in the docket which (a) grants Securus a waiver of Rule R13-9(d) and (b) authorizes Securus to implement a cap or maximum per minute calling rate of $0.24 for 0+ local automated collect station-to-station calls in North Carolina no later than December 1, 2016.

9. The Stipulation is the product of give-and-take negotiations, and no portion of the Stipulation shall be binding on the Stipulating Parties unless the entire Stipulation is accepted by the Commission.

<u>Securus' December 1, 2016 Cover Letter and Reply Comments</u>

a. <u>Cover Letter</u>

In the Cover Letter, Counsel for Securus addressed GTL's request that the Commission grant the same relief from the requirements of Commission Rule R13-9(d) to GTL and other members of the ICS industry that Securus was requesting from the Commission in its Petition. Securus strongly opposed GTL's request in the Cover Letter. Securus observed that it first filed a

Verified Petition requesting such relief from the Commission more than three months ago, that its Verified Petition was accompanied by a North Carolina specific cost study that supported its contention that it was not recovering its costs of providing ICS services in North Carolina by utilizing the Windstream Concord surrogate rate mandated by Commission Rule R13-9(d), that its figures had been duly noted, vetted and considered by the Public Staff and that it had reached a stipulated settlement with the Public Staff with regard to agreed-upon stipulated rate as a result of give and take negotiations. Further, Securus observed that, although its request for relief from the surrogate rate had been made more than three months ago, neither GTL nor any other member of the industry had sought formal relief from the Commission from the requirements of the Commission Rule R13-9(d); nor had GTL or any other ICS provider filed a North Carolina cost study or any other evidence demonstrating that GTL or any other ICS provider is entitled to the same relief that Securus is requesting.

b. The Hopfinger Affidavit

In the Affidavit, Mr. Hopfinger states that he is the Director of Regulatory and Governmental Affairs for Securus Technologies, Incorporated, and that he has personal knowledge of the facts stated in the affidavit and could testify to the same. Further, Mr. Hopfinger states that he supports the Stipulation and that the newly proposed stipulated rate is just and reasonable and appropriate for implementation in North Carolina for the following reasons:

1. The newly proposed stipulated rate for North Carolina compares favorably with rates currently in effect in other southern states.

2. The Louisiana Public Service Commission adopted a capped rate of $0.25 for prepaid inmate calling by Order on March 22, 2016. The newly proposed stipulated rate for North Carolina would be one cent less per minute than the rate adopted in Louisiana.

3. The Alabama Public Service Commission currently has a rate of $0.28 per minute for inmate calling service which is scheduled to decline to $0.25 per minute on July 1, 2017. The newly proposed stipulated rate for North Carolina would be one cent less per minute than the rate that will become effective in Alabama in 2017.

4. Mississippi currently has a capped rate of $0.50 per minute for inmate calling service. The newly proposed stipulated per minute rate for North Carolina would only be 48% of the maximum rate currently in effect in Mississippi.

5. By statute, inmate telephone service is deregulated in Florida. Thus, there are no rate caps or tariffs in Florida and there are no restrictions on intrastate inmate calling rates. Prior to deregulation, Securus had a tariffed rate of $3.00 plus $0.30 per minute and a prepaid card/debit rate of $0.50 per minute.

6. South Carolina's current local inmate calling rate which became effective on June 20, 2016, is $1.75 for the first minute and $0.12 for each additional minute. The

rate was previously capped at $2.50 per call. The newly proposed stipulated rate for North Carolina would be $0.19 lower than a 12-minute call made in South Carolina.

7. Georgia currently has a rate cap of $0.18 per minute, which is below cost for Securus. Securus has proposed a rate of $0.31 per minute pending approval before the Georgia Public Service Commission. The newly proposed stipulated rate is $0.07 less per minute than the rate which Securus proposes to implement in Georgia.

8. The newly proposed stipulated rate of $0.24 per minute is $0.04 less than the local inmate calling rate of $0.28 which is supported by the cost study filed by Securus in this docket.

9. The current capped rate in North Carolina under Rule R13-9(d) for a 0+ local automated collect station-to-station inmate call is a maximum of $1.71. Under the newly proposed stipulated rate of $0.24, a call of seven minutes or less in duration would be less costly under the newly proposed stipulated rate than under the Rule R13-9(d) rate.

After carefully considering the aforementioned and the record proper, the Commission finds and so concludes that the two issues presently before the Commission for decision are: (1) Whether the Joint Stipulation presented by the Petitioner and Public Staff should be adopted and approved; and (2) If the Joint Stipulation is adopted and approved, should the relief established thereby, be granted to GTL and any other ICS providers operating in North Carolina. With regard to the former, the Commission finds and so concludes that the Joint Stipulation between the Petitioner and the Public Staff, as herein modified, should be adopted and approved. With regard to the latter, the Commission finds and so concludes the GTL's request that the Commission grant it and any other ICS provider operating in this State the same relief that the Commission grants Securus should be and is hereby denied. The Commission reasons as follows.

I. The Joint Stipulation, as herein modified, should be adopted and approved.

On August 30, 2016, Securus filed a Verified Petition with the Commission requesting that the Commission waive the provisions of Commission Rule R13-9(d) as it applied to Securus. In the Verified Petition, Securus states that the FCC's 2015 ICS Order has caused serious problems in providing ICS service in a cost effective manner in North Carolina. To comply with Commission Rule R13-(d) and with the requirements of the FCC's 2015 ICS Order that are currently in effect, Securus has restructured its charge for ICS collect calls from a flat, per-call rate to a per-minute charge with the total per-call charge capped at the Windstream Concord rate. Also, in the Verified Petition, Securus states that the changes caused by the FCC's 2015 ICS Order have sharply impacted Securus' ability to earn a fair rate of return and the impact caused thereby is demonstrated in the confidential cost study provided to the Commission. Further, in the Verified Petition, Securus, states that it is not recovering its costs to provide local automated collect calls in North Carolina as a result of these changes and that authorizing Petitioner to charge the requested rate of $0.28 per minute would allow Petitioner to recover its costs of service and earn a reasonable rate return on its investment. Standing alone, this is persuasive evidence to support Securus' request for relief from Commission Rule R13-9(d).

Further, evidence supportive of the requested relief is found in the Hopfinger Affidavit. In the Affidavit, Mr. Hopfinger provides a detailed analysis of the prevailing rates for ICS services being charged or being contemplated in a number of surrounding southern states. According to Mr. Hopfinger, the stipulated proposed rate is just and reasonable and compares favorably with the rate currently in effect in the surrounding states. Additionally, in the Affidavit, Mr. Hopfinger indicates that under the newly proposed stipulated rate of $0.24 per-minute, a call of seven minutes or less in duration would be less costly under the stipulated rate than under the Commission Rule R13-9(d) rate. Finally, Mr. Hopfinger states that the newly proposed stipulated rate is $0.04 less than the local inmate calling rate which is supported by Securus' North Carolina cost study which was filed as part of the Verified Petition.

Finally, the Commission observes that the Public Staff has signed off on the Stipulated Agreement. By statute, the Public Staff is responsible for reviewing, investigating and making appropriate recommendations to the Commission with respect to the reasonableness of rates charged or proposed to be charged by any public utility. In the performance of that duty, over the past 90 plus days the Public Staff has submitted discovery requests to the Petitioner, reviewed and analyzed the Petitioner's response to those requests and reviewed and analyzed the factual foundations underlying the Petitioner' cost study and justifications for the Petitioner's rate request. After performing this function, the Public Staff entered into a Stipulation with the Petitioner that recommends that the Commission waive the requirements of Commission Rule R13-9(d) as it applies to Securus and that the Commission authorize Securus to charge a rate subject to a cap or maximum per minute calling rate of $0.24 for local automated collect station-to-station calls in North Carolina. Lastly, the Public Staff recommended that the Commission find that the agreed upon stipulated rate is just and reasonable.

The preceding evidence is substantive. It should be and is accorded substantial weight by the Commission. Based upon this evidence and the lack of any evidence contradicting such evidence, the Commission therefore finds and so concludes that the Joint Stipulation is the product of the give-and-take among the Stipulating Parties during their settlement negotiations, and that the current requirements of Rule R13-9(d) as applied to Securus should be waived. The Commission reaches this conclusion based mainly on two factors: (1) Securus' cost of service study that supports its contention that it is not recovering its costs of providing ICS services in North Carolina by utilizing the Windstream Concord surrogate rate mandated by Commission Rule R13-9(d), and (2) the Public Staff investigated the matter and recommended that Securus be authorized to charge a maximum rate of $0.24 per minute. Based upon the aforementioned, the Commission therefore concludes that the rate that Securus is authorized to charge should be subject to a cap or maximum per minute calling rate of $0.24 for local automated collect station-to-station calls in North Carolina, that such stipulated rate is just and reasonable, that Securus' request that the provisions of Commission Rule R13-9(d) as it applies to Securus be waived should be granted, and that Securus' new rate should be allowed to become effective as of January 1, 2017.

II. GTL's request that the Commission grant it and other ICS providers operating in this State the same relief that the Commission grants Securus should be and is hereby denied.

As the Commission noted above, the only party, other than the Petitioner and the Public Staff, to file comments in this docket was GTL. In its comments, GTL supports Securus' requests that: (1) the Commission waive the requirements of Commission Rule R13-9(d) as applied to Securus; and (2) that the Commission approve Securus' proposal to implement a cap or maximum calling rate of $0.28 per minute for local automated collect station-to-station calls in North Carolina. GTL does not, however, support Securus' implicit (and now explicit) request that the Commission grant the requested relief in this docket only to Securus. Instead, GTL urges the Commission to extend any relief that we grant to Securus from the requirements of Commission Rule R13-9(d) to GTL and other members of the ICS industry. GTL contends that to do otherwise, i.e., to grant such relief only to Securus, would give Securus a competitive advantage over other members in the industry in negotiating and securing ICS contracts at the various correctional facilities in the State. Securus strongly opposes GTL's request.

After carefully considering GTL's request, and Securus' response in opposition to the request, as well as the record proper, the Commission, in its discretion, finds and so concludes that GTL's request that: (1) the Commission waive the requirements of Commission Rule R13-9(d) as its applies to GTL and/or other members of the ICS industry operating in North Carolina; and (2) that the Commission allow GTL and other members of the ICS industry operating in North Carolina to implement a cap or maximum calling rate of $0.24 per minute for local automated collect station-to-station calls in North Carolina should be and is hereby denied.

As the Commission observed in the preceding discussion, there are two main factors which persuaded the Commission to grant relief to Securus, i.e., (1) the North Carolina specific cost study that Securus filed supporting its contention that it is not recovering its costs of providing ICS services in North Carolina by utilizing the Windstream Concord surrogate rate mandated by Commission Rule R13-9(d), and (2) the Public Staff investigation that resulted in its recommendation that Securus be authorized to charge a maximum rate of $0.24 per minute. Because of these two factors, the Commission could reasonably conclude: (a) that Securus was entitled to the relief that it was requesting; (b) that the stipulated rate of $0.24 per minute was just and reasonable and would provide Securus with the opportunity to recover its costs of service and to earn a reasonable rate return on its investment; and (c) that, in our discretion, the requested relief should be granted.

To date, GTL has not filed a cost study to support its request that the Commission extend that same relief that the Commission is granting to Securus in this docket to GTL and/or other members of the ICS industry operating in this State. Nor has GTL subjected its costs and expenses to an investigation by the Public Staff.[1] Consequently, the Public Staff has neither investigated a GTL specific request for waiver relief from Commission Rule R13-9(d) nor recommended an authorized maximum per minute rate based on GTL's costs.

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[1] The Commission takes judicial notice that on December 1, 2016, Pay Tel Communications, Inc. (Pay Tel), an ICS provider operating in North Carolina, filed a Verified Petition for Waiver of Commission Rule R13-9(d) as it applies to Pay Tel. In support of its request, Pay Tel attached a confidential exhibit to the Verified Petition which included highly sensitive and proprietary information regarding PayTel's costs of service in North Carolina. The Commission will rule on Pay Tel's Verified Petition in due course.

As a result, there is insufficient company specific or industry specific evidence in the record in this docket to support Commission conclusions that:(a) GTL and/or the other ICS providers are not recovering its/their costs to provide local automated collect calls in North Carolina by charging the Windstream Concord surrogate rate; (b) that the stipulated rate of $0.24 per minute is just and reasonable for GTL and the industry as a whole to charge and the stipulated rate would provide GTL and/or other ICS providers operating in this State with the opportunity to recover its/their costs of service and earn a reasonable rate return on its/their investment; and (c) that the requested relief should be granted. Each conclusion and evidence in support thereof is necessary for the Commission to grant the relief requested by GTL. In the absence of such, it is improper for the Commission to exempt GTL and/or the industry as a whole from the requirements of Commission Rule R13-9(d), based on North Carolina specific data relating only to Securus' costs and cost recovery. Thus, GTL's request that the Commission grant it the same relief that Securus is requesting must be and is hereby denied.[1]

IT IS, THEREFORE, ORDERED that:

1. Securus' request that the current requirements of Rule R13-9(d) as applied to Securus should be waived is hereby granted;

2. Securus is authorized to charge a cap or maximum per minute calling rate of $0.24 for local automated collect station-to-station calls in North Carolina;

3. The newly proposed stipulated rate should be allowed to become effective as of January 1, 2017; and

4. GTL's request that any relief granted to Securus in this docket be extended to GTL and other members of the ICS industry is hereby denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of January, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

Commissioners ToNola D. Brown-Bland, Jerry C. Dockham and James G. Patterson, respectively, did not participate in the decision.

[1] The Commission notes that its decision to deny GTL's request that the Commission waive the requirements of Commission Rule R13-9(d) does not bar GTL and/or any other ICS provider operating in this State from petitioning the Commission for such relief based upon its individual circumstances. See Footnote 3.

DOCKET NO. P-55, SUB 1934
DOCKET NO. P-100, SUB 133C

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. P-55, SUB 1934

In the Matter of Petition of AT&T North Carolina for Order Confirming Relinquishment of Eligible Telecommunications Carrier Designation in Specified Areas DOCKET NO. P-100, SUB 133C In the Matter of Designation of Carriers Eligible for Universal Service Support	)	ORDER CONFIRMING AT&T'S RELINQUISHMENT OF ETC DESIGNATION

BY THE COMMISSION: On May 2, 2017, BellSouth Telecommunications, LLC d/b/a AT&T North Carolina (AT&T) filed a Petition in Docket No. P-55, Sub 1934 requesting the Commission to issue an order confirming the relinquishment of AT&T's Eligible Telecommunications Carrier (ETC) designation for a portion of its service area in North Carolina, as specified in the Petition, effective October 30, 2017. The Commission also placed a copy of AT&T's Petition into Docket No. P-100, Sub 133c – Designation of Carriers Eligible for Universal Service Support.

In its Petition, AT&T noted that it is participating in the Federal Communications Commission's (FCC's) Connect America Fund (CAF) Phase II program, which is enabling AT&T to bring more broadband to high cost, primarily rural areas in North Carolina. AT&T stated that, as a condition of its participation in this program, AT&T is retaining its ETC designation in certain census blocks for which it is eligible to receive CAF Phase II funding, referred to in the Petition as the CAF II Census Blocks. AT&T noted that the Petition refers collectively to the CAF II Census Blocks in which AT&T is retaining its ETC designation as "the retained area". AT&T also noted that by its Petition, it is relinquishing its ETC designation for all of the remaining areas in which it currently is designated as an ETC.

On May 5, 2017, the Commission issued an Order Requesting Comments on AT&T's Petition. The Order specified that interested parties, including the Public Staff and the Attorney General, could file initial comments on AT&T's Petition by no later than May 19, 2017, and AT&T could file reply comments, as necessary, by no later than May 26, 2017.

On May 18, 2017, the Public Staff filed a Motion for Extension of Time to file initial and reply comments. The Public Staff noted that due to the press of business, the Public Staff required an extension of time for filing comments. Therefore, the Public Staff requested a seven-day extension of time for all interested parties to file comments on the Petition, and a seven-day extension of time for AT&T to file reply comments. The Public Staff also noted that AT&T had indicated to the Public Staff that it consented to the seven-day extensions of time for the filing of initial comments and reply comments. By Order dated May 19, 2017, the Commission granted the Public Staff's Motion for Extension of Time. Therefore, interested parties, including the Public Staff and the Attorney General, could file initial comments on AT&T's Petition by no later than May 26, 2017, and AT&T could file reply comments, as necessary, by no later than June 2, 2017.

Initial comments were filed on May 26, 2017 by the Public Staff. AT&T filed reply comments on June 1, 2017.

AT&T'S PETITION

AT&T stated that, pursuant to 47 U.S.C. § 214(e)(4) and 47 C.F.R. § 54.205, it was requesting that the Commission issue an order confirming relinquishment of its ETC designation for the portion of its service area in North Carolina specified in its Petition, effective October 30, 2017.

AT&T noted that it is participating in the FCC's CAF Phase II program that is enabling AT&T to bring more broadband to high cost, primarily rural areas in North Carolina. AT&T stated that as a condition of its participation in this program, AT&T is retaining its ETC designation in certain census blocks for which it is eligible to receive CAF Phase II funding, referred to in its Petition as the CAF II Census Blocks. AT&T noted that its Petition refers collectively to the CAF II Census Blocks in which AT&T is retaining its ETC designation as "the retained area."

AT&T maintained that by its Petition, it is relinquishing its ETC designation for all of the remaining areas in which it currently is designated an ETC ("the relinquishment area"). AT&T asserted that this is AT&T's right under federal law because the relinquishment area is served by at least one other ETC. AT&T clarified that, by its Petition, AT&T is not discontinuing any legacy voice service, and AT&T's ETC relinquishment will not affect the availability of any AT&T legacy voice service in any area of the State. AT&T stated that it will continue to offer and provide legacy voice service in all of its service territory (including the relinquishment area), and it will continue to comply with applicable service obligations of federal and state law in its service territory (including the relinquishment area), unless and until it separately obtains any necessary permission to stop providing retail legacy voice service.

AT&T specified that the only consumer impact of this relinquishment is that consumers in the relinquishment area will no longer receive the Lifeline discount on voice service from AT&T. AT&T noted that Lifeline customers in the relinquishment area can continue receiving any service offered by AT&T at standard AT&T prices (including applicable surcharges, fees and taxes), or if they prefer, they can choose to receive a Lifeline discount from another ETC. AT&T noted that it will provide ample advance notice to all affected customers.

AT&T maintained that federal law provides an objective standard for ETC relinquishment. AT&T noted that 47 U.S.C. § 214(e)(4) states, in pertinent part:

> A State commission . . . shall permit an eligible telecommunications carrier to relinquish its designation as such a carrier in any area served by more than one eligible telecommunications carrier. . .

AT&T further noted that its ETC relinquishment more than meets this controlling standard, because every wire center in the relinquishment area is served by at least four other ETCs, and in some instances as many as seven other ETCs.

Additionally, AT&T maintained that its ETC relinquishment will have only a nominal impact on North Carolina consumers, who have demonstrated a clear preference for obtaining their Lifeline discount from ETCs other than AT&T. AT&T noted that over the past eight years, AT&T has seen its own North Carolina Lifeline subscribership shrink by 94%. AT&T stated that, as of the end of 2016, AT&T was serving less than 1% of the Lifeline subscribers in the State – in other words, more than 99% of Lifeline customers in North Carolina have elected to obtain their Lifeline discount from an ETC other than AT&T. AT&T asserted that there should be no concerns with AT&T relinquishing its ETC status when so many other ETCs are serving North Carolina consumers, and so many North Carolina customers prefer to receive Lifeline from ETCs other than AT&T.

AT&T noted that AT&T incumbent local exchange carriers (ILECs) also are relinquishing their ETC designations in other states. AT&T commented that, to date, six State commissions have approved AT&T's relinquishment – Alabama, Mississippi, Missouri, Oklahoma, Tennessee and Wisconsin; and that Petitions are pending in Georgia, Florida, Indiana, Kansas and South Carolina[1].

AT&T noted that it is an ILEC in North Carolina. AT&T further noted that on December 15, 1997, the Commission granted AT&T's request, pursuant to 47 U.S.C. § 214(e)(1), for designation as an ETC within its ILEC service area.[2] AT&T noted that Exhibit A attached to its Petition sets out the wire centers and associated exchanges in which AT&T currently is designated as an ETC in North Carolina. AT&T stated that as an ETC, AT&T has been eligible to receive federal universal service funding in accordance with 47 U.S.C. § 254, in exchange for which it has been required to offer and advertise supported services pursuant to 47 C.F.R. § 54.201(d) and meet the obligations associated with the universal service programs in which it participates.[3] AT&T maintained that, since its inception, federal universal service funding has included "high cost" support to deploy and maintain networks in rural and other high-cost areas,

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[1] The Commission notes that the South Carolina Public Service Commission approved AT&T's Petition for Order Confirming Relinquishment of Eligible Telecommunications Carrier Designation in Specified Areas on May 3, 2017.

[2] Order Granting Waivers and Designating Carriers, *In the Matter of Carriers Eligible for Universal Service Support*, Docket No. P-100, Sub 133c (December 15, 1997).

[3] *See* 47 U.S.C. § 214(e)(1).

as well as reimbursement from the Lifeline Assistance Program (Lifeline) for offering services to eligible low-income consumers at discounted prices.

AT&T asserted that its relinquishment of its ETC designation in certain areas of North Carolina is prompted, in part, by changes to the universal service program at the federal level. AT&T commented that, most relevant here, the FCC has changed its approach to disbursing high cost universal service support. [1] AT&T noted that for price cap carriers like AT&T, the restructured program is referred to as CAF Phase II, and AT&T has accepted the FCC's offer of CAF II funding in North Carolina – a decision that will enable AT&T to provide broadband in high cost, primarily rural portions of the State.[2]

AT&T noted that unlike federal USF funding in the past, CAF Phase II funding is made available specifically by census blocks[3] rather than by larger areas like wire centers or service areas. AT&T maintained that the FCC's laser focus down to the census block level is intended to ensure high cost support is reaching its target and is not being used to support broadband in areas already served by other broadband providers, or in areas where it is commercially feasible to provide broadband without a subsidy. AT&T further noted that having accepted CAF Phase II funding, AT&T is obligated to: (a) remain an ETC in CAF II Census Blocks[4] for the full six-year funding term; and (b) offer the Lifeline discount to eligible customers who reside in CAF Phase II Census Blocks. Accordingly, AT&T stated that it is retaining its ETC designation in the CAF Phase II Census Blocks. AT&T stated that because it is no longer eligible for high cost universal service

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[1] *See generally* Report and Order, *Connect America Fund*, 29 FCC Rcd. 15644 (2014); Report and Order and Further Notice of Proposed Rulemaking, *Connect America Fund*, 26 FCC Rcd. 17663 (2011) (subsequent history omitted).

[2] *See* August 27, 2015 Letter from James Cicconi in FCC Docket No. 10-90. AT&T noted that it did not make the decision lightly – it declined the FCC's offer of CAF Phase II funding in three of the twenty-one states in which it is a traditional wireline ILEC (Missouri, Nevada and Oklahoma).

[3] AT&T commented that, as explained in more detail in Exhibit E attached to its Petition, census blocks are statistical areas bounded by visible features, such as streets, roads, streams, and railroad tracks, and by nonvisible boundaries, such as selected property lines and city, township, school district and county limits and short line- of-sight extensions of streets and roads. https://www.census.gov/geo/reference/gtc/gtc_block.html

[4] AT&T stated that, in addition to identifying specific census blocks as eligible for CAF Phase II funding, the FCC also allows AT&T to use CAF Phase II support in "Extremely High Cost" census blocks to meet its CAF Phase I broadband commitments. *See* 47 C.F.R. § 54.310(c)(1). The six-year funding term only applies to those Extremely High Cost census blocks in which AT&T actually uses CAF Phase II support. As noted in Exhibit B attached to AT&T's Petition, AT&T is retaining its ETC designation in some "Extremely High Cost" census blocks in North Carolina. Census block boundaries do not always coincide with wire center boundaries. Where a portion of a CAF II Census Block falls outside AT&T North Carolina's traditional wireline footprint, AT&T North Carolina is retaining its ETC designation only in the portion of the census block that is within AT&T's traditional footprint.

support in the areas outside of the CAF Phase II Census Blocks,[1] AT&T is relinquishing its ETC designation in all such areas.[2]

AT&T stated that its ETC relinquishment also is driven by the dramatic changes in the telecommunications marketplace in North Carolina that have occurred since AT&T was designated as an ETC. AT&T asserted that customers today increasingly are replacing AT&T's and other ILECs' traditional wireline residential voice services with numerous other options, including wireless and Voice over Internet Protocol (VoIP) services. AT&T maintained that, as a result, the overall number of traditional (*i.e.*, circuit-switched plain old telephone service (POTS)) ILEC wireline residential customers has decreased substantially. AT&T noted that between 2005 and 2015, the number of traditional ILEC residential wireline customers in North Carolina decreased by 66%, from 2.9 million lines to 994,000 lines.[3] AT&T stated that its traditional residential retail lines in North Carolina decreased by 81% during the same period; and during 2016 alone, AT&T's residential line count dropped nearly 20% from what had been in service at the end of 2015.

AT&T asserted that its number of Lifeline customers in North Carolina likewise has plummeted, even as the total number of Lifeline customers in the state has grown, because consumers have demonstrated a strong preference for obtaining their Lifeline discount from other ETCs. AT&T noted that from 2008 through 2016, the number of AT&T retail Lifeline customers declined by 94%, such that by the end of 2016, AT&T served less than 1% of North Carolina's 320,331 Lifeline subscribers.

AT&T argued that that decline in AT&T's Lifeline subscribership stands in stark contrast to the dramatic increase in overall Lifeline subscribership in the state – between 2008 and 2016, overall North Carolina Lifeline subscribership increased by 154%. AT&T maintained that it is clear that an increasing number of North Carolinians are taking advantage of the Lifeline discount, but they prefer to obtain the discount from carriers other than AT&T.

AT&T noted that Exhibit B as attached to its Petition sets out the CAF Phase II Census Blocks (and associated wire centers) in which AT&T is retaining its ETC designation. AT&T stated that after the relinquishment effective date, that area will be AT&T's ETC service area in North Carolina. AT&T maintained that it will continue offering the Lifeline discount to eligible customers in the retained area. AT&T noted that, as of the end of 2016, 91 AT&T customers were receiving the Lifeline discount in the North Carolina retained area.

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[1] AT&T accepted CAF Phase I Incremental Support (Incremental Support) to deploy broadband service, including some locations in North Carolina. AT&T's Incremental Support service obligation ends with its Form 481 submission to the FCC, with a copy to the Commission, no later than July 1, 2017, which is prior to the relinquishment effective date identified in the Petition.

[2] If AT&T elects to participate in the FCC's CAF Phase II reverse auction and is awarded extremely high-cost service areas through that competitive bidding process, AT&T will file a new request for ETC designation in those areas at that time. *See* Report and Order and Further Notice of Proposed Rulemaking, *Connect America Fund*, 31 FCC Rcd. 5949, ¶¶ 149-56 (May 25, 2016) (establishing the ETC designation process for CAF II auction winning bidders).

[3] *See* FCC Local Competition Reports (2005-2013) and FCC Voice Telephone Services Reports (2014-2015).

AT&T asserted that because it is not eligible for CAF Phase II support in areas that are not identified in Exhibit B, and because customers overwhelmingly prefer to obtain Lifeline from ETCs other than AT&T, AT&T is relinquishing its ETC designation (and will no longer offer the Lifeline discount to customers in the relinquishment area, effective October 30, 2017) in the entirety of its current ETC service area except for the census blocks identified in Exhibit B. AT&T noted that, accordingly, the "relinquishment area" consists of all portions of AT&T's current ETC service area that are not identified in Exhibit B. AT&T stated that, as of the end of 2016, AT&T had 1,701 Lifeline subscribers in the relinquishment area as shown on Exhibit C (AT&T Lifeline Customers & CETCs Designated in AT&T's Current ETC Service Area) attached to its Petition.

AT&T maintained that, to further assist in identifying the areas in which AT&T is retaining and relinquishing its ETC designation, Exhibit D attached to its Petition is a map that generally depicts the retained area in green and the relinquishment area in white. Additionally, AT&T stated that Exhibit E attached to its Petition explains how the United States Census Bureau's website, which provides a wealth of information about census blocks, can be used for various purposes such as determining which census block is associated with a given physical address and viewing maps depicting a given census block.

AT&T noted that it is not providing an exhibit listing the census blocks in which it is relinquishing its ETC designation. AT&T asserted that it has no business or regulatory reason to create or maintain a list of census blocks and associated wire centers for which it will no longer be an ETC – rather, AT&T's need to track information for certain census blocks arises solely from its participation in the CAF Phase II program. AT&T argued that, moreover, an exhibit consisting of hundreds of pages of census block numbers and associated wire center designations would be of no use whatsoever to the Commission, its Staff, or anyone else. AT&T stated that, in contrast, the map attached as Exhibit D and the information addressing the Census Bureau's website in Exhibit E will assist in identifying, if needed, specific areas in which AT&T is retaining and relinquishing its ETC designation.

AT&T maintained that the only change for AT&T customers in the relinquishment area is that the Lifeline discount will no longer be available from AT&T. AT&T noted that after relinquishment, AT&T will continue to offer and provide service in the relinquishment area. AT&T stated that it also will continue to fulfill any retail service obligations imposed by non-ETC provisions in state or federal law, unless and until AT&T separately obtains any necessary permission to stop providing service. AT&T stated that all customers in the relinquishment area, including former AT&T Lifeline customers who choose to keep their AT&T service, will have access to services offered by AT&T at standard AT&T prices, including all applicable surcharges, fees and taxes. Finally, AT&T maintained that its relinquishment will not affect either the ability of other ETCs to participate in the federal universal service program, including Lifeline, or the amount of support available in North Carolina.

AT&T noted that in 47 U.S.C. § 214(e)(2) and (4) and 47 C.F.R. § 54.205, Congress and the FCC delegated authority to state commissions to designate carriers as ETCs and permit carriers to relinquish their ETC designation. AT&T stated that the standard for relinquishing an ETC designation is set forth in 47 U.S.C. § 214(e)(4), which states, in pertinent part:

> A State commission...**shall permit an eligible telecommunications carrier to relinquish its designation** as such a carrier **in any area served by more than one eligible telecommunications carrier.** An eligible telecommunications carrier that seeks to relinquish its eligible telecommunications carrier designation for an area served by more than one eligible telecommunications carrier shall give advance notice to the State commission...of such relinquishment (Emphasis added by AT&T).

AT&T noted that 47 U.S.C. § 214(e)(4) also provides, in part:

> Prior to permitting a telecommunications carrier designated as an eligible telecommunications carrier to cease providing universal service in an area served by more than one eligible telecommunications carrier, the State commission...shall require the remaining eligible telecommunications carrier or carriers to ensure that all customers served by the relinquishing carrier will continue to be served, and shall require sufficient notice to permit the purchase or construction of adequate facilities by any remaining eligible telecommunications carrier.

AT&T asserted that the law does not treat relinquishment of an ETC designation by an ILEC any differently than relinquishment by other designated ETCs, and the Commission has previously allowed carriers to relinquish their ETC designations.[1]

AT&T maintained that this language is inapplicable to this Petition because AT&T will not discontinue any service as a result of the Commission granting this Petition. *See e.g.,* Order Confirming AT&T Mississippi's Relinquishment of its Eligible Telecommunications Carrier Designation in Specified Areas, *In re Verified Petition of AT&T Mississippi for an Order Confirming Relinquishment of its Eligible Telecommunications Carrier Designation in Specified Areas,* Docket No. 2016-UA-213, at 4 (Miss. P.S.C. April 13, 2017) (Mississippi Relinquishment Order)("the requirements related to continuation of service and adequate notice are not applicable in this matter because AT&T will not discontinue any service as a result of the Commission confirming partial relinquishment of the Company's ETC status."); Order Confirming AT&T Tennessee's Relinquishment of Its Eligible Telecommunications Carrier Designation in Specified Areas, *In re Verified Petition of AT&T Tennessee for an Order Confirming Relinquishment of its Eligible Telecommunications Carrier Designation in Specified Areas,* Docket No. 16-00123, at 4 (Tenn. Reg. Auth. Mar. 24, 2017)(Tennessee Relinquishment Order)("AT&T will not cease

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[1] *See, e.g.,* Order Granting Petition to Discontinue Service and Cancelling Designation as Eligible Telephone Carrier, *In the Matter of Petition of Nexus Communications, Inc. to Discontinue Services and Cancel Certificate of Public Convenience and Necessity,* Docket No. P- 1310, Sub 1 (March 5, 2015); Order Granting Petition to Discontinue Service and Cancelling EveryCall Communications, Inc.'s Designation as Eligible Telephone Carrier, *In the Matter of Petition of EveryCall Communications, Inc., for Approval of Proposed Service Discontinuance,* Docket No. P-1278, Sub 3 (May 16, 2014); Order Granting Petition to Discontinue Service and Cancelling Unity Telecom's Designation as Eligible Telephone Carrier, *In the Matter of Petition of Unity Telecom, LLC for Approval of Proposed Service Discontinuance,* Docket No. P-836, Sub 6 (September 4, 2013); Order Cancelling Absolute Home Phones' Designation as Eligible Telephone Carrier, *In the Matter of Petition of Absolute Home Phones, Inc., for Cancellation of Eligible Telephone Certificate,* Docket No. P-1481, Sub 2 (February 25, 2013); Order Cancelling Affordable Phones Services' Designation as Eligible Telephone Carrier, *In the Matter of Petition of Affordable Phone Services, Inc., for Cancellation of Eligible Telephone Certificate,* Docket No. P-1272, Sub 3 (February 25, 2013).

providing universal service in the specified relinquishment area and therefore, additional requirements on remaining ETCs are not applicable.").

AT&T stated that federal law also does not require a carrier to relinquish its ETC designation only for its entire service area or entire wire centers. Rather, AT&T noted that Section 214(e)(4) provides that a state commission "shall permit" relinquishment for "any area" served by more than one ETC. AT&T thus argued that nothing in Section 214 prohibits a carrier from relinquishing its ETC status for only part of its designated service area or part of a wire center. AT&T maintained that this was a logical choice by Congress, since there is no guarantee that other ETCs will be designated in a carrier's entire service area. AT&T noted that several state commissions have granted carriers' requests to partially relinquish their ETC status, including Alabama, Illinois, Kentucky, Mississippi, Missouri, South Dakota, Tennessee, Washington, and Wisconsin.[1]

AT&T stated that although the FCC does not appear to have directly addressed partial relinquishment of ETC status, it has made several forbearance rulings and established exemptions and eligibility requirements that rely on census blocks (instead of entire wire centers) as a relevant geographic area for applying ETC obligations or exemptions. AT&T asserted that these actions necessarily acknowledge that ETC designation or relinquishment can occur on a partial wire center

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[1] *See* Mississippi Relinquishment Order; Tennessee Relinquishment Order; Final Decision, *Request by Wisconsin Bell, Inc. d/b/a AT&T Wisconsin, to Relinquish its Status as an Eligible Telecommunications Carrier in Certain Parts of its Service Territory,* Docket No. 6720-TI-225 (WI PSC March 13, 2017) (Order directed AT&T to seek FCC guidance on whether AT&T Wisconsin could establish an ETC designation based on census blocks rather than wire centers. Order at 8-9. On April 11, 2017, the Wisconsin Commission Staff notified AT&T that the FCC Staff had confirmed that AT&T's ETC relinquishment complied with federal law and that no further FCC review or approval was required.); Order, *In re Implementation of the Universal Service Requirements of Section 254 of the Telecommunications Act of 1996,* Docket No. 25980 (Ala. PSC March 9, 2017)(Alabama Relinquishment Order); Order, *In the Matter of Petition of Bluegrass Wireless LLC for a Partial Relinquishment of Its Eligible Telecommunications Carrier Designation,* Case No. 2015-00055, 2015 WL 1287654 (Ky. PSC Mar. 19, 2015); Order, *USCOC of Central Illinois, LLC: Petition to Partially Relinquish Its Designation as an Eligible Telecommunications Carrier Under 47 U.S.C. § 214(e)(2),* Docket No. 13-0480, 2014 WL 98655 (Ill. C.C. Jan. 7, 2014); Order Approving Partial Relinquishment of Eligible Telecommunications Carrier Designation, *In the Matter of the Application of USCOC Missouri, LLC for Designation as an Eligible Telecommunications Carrier Pursuant to the Telecommunications Act of 1996,* No. TO-2—5-0384, 2013 WL 6971040 (Mo. PSC Dec. 23, 2013); Order Granting Petition for Partial Relinquishment of Eligible Telecommunications Carrier Designation, *In the Matter of Petition of RCC Minnesota, Inc. for Designation as an Eligible Telecommunications Carrier,* No. UT-23033, 2009 WL 521969 (Wash. UTC Feb. 26, 2009); Order Approving Partial Relinquishment of ETC Designation, *In the Matter of the Petition of Cellco Partnerships and Its Subsidiaries and Affiliates to Amend and Consolidate Eligible Telecommunications Carrier Designations in the State of South Dakota and to Partially Relinquish ETC Designations,* No. TC10-090, 2010 WL 10283843 (S.D. PUC Nov. 18, 2010); Order Approving Petition to Partially Relinquish Designation as an Eligible Telecommunications Carrier, *In the Matter of Petition of Brookings Municipal Utilities d/b/a Swiftel Communications for an Approval of a Partial Relinquishment of Its Designation as an Eligible Telecommunications Carrier,* No. TC08-103, 2008 WL 10051437 (S.D. PUC Oct. 3, 2008).

basis,[1] and they are fully consistent with the FCC's decision to make CAF Phase II funding for ETCs available based on census blocks instead of wire centers or entire service areas. AT&T maintained that the FCC clearly knew making CAF Phase II funding available at the census block level would affect the areas where carriers would want to obtain or relinquish ETC status.

AT&T stated that, in short, nothing in Section 214(e) or the FCC's orders or rules requires ETC designations to be made or relinquished only for an entire service area or for entire wire centers, and several state commissions have approved partial relinquishments. Accordingly, AT&T maintained that there is no legal barrier to AT&T's relinquishment of its ETC designation in part of its service area or parts of wire centers where it no longer receives high cost support.

AT&T asserted that it meets the standard for relinquishing its ETC designation because, as set forth in Exhibit C, each wire center in the relinquishment area has at least four other designated ETCs, and in some instances as many as seven other ETCs. AT&T stated that, to its knowledge, each of these providers remains designated an ETC in those wire centers. AT&T stated that as a designated ETC, each of these providers is obligated to provide Lifeline upon reasonable request to eligible customers in the areas for which it obtained its ETC designation, and consumers clearly prefer to receive – and are actually receiving – their Lifeline discount from these other ETCs. AT&T noted that the number of AT&T Lifeline subscribers in North Carolina has steadily declined (by over 94% between 2008 and 2016) to the point that as of the end of 2016, more than 99% of Lifeline customers in North Carolina are served by an ETC other than AT&T.

AT&T asserted that it will ensure that its Lifeline customers in the relinquishment area receive ample notice of the need to select another ETC in order to continue receiving a Lifeline discount. AT&T stated that at least 60 days prior to the relinquishment effective date, AT&T will provide notice in a separate letter via U.S. Mail to each of its affected Lifeline customers explaining that: AT&T will no longer offer the Lifeline discount; and if the customer does not choose another Lifeline provider, AT&T's standard prices (including applicable surcharges, fees and taxes) will

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[1] See, e.g., Report and Order, *In the Matter of Connect America Fund, ETC Annual Reports and Certifications, Petition of USTelecom for Forbearance Pursuant to 47 U.S.C. § 160(c) from Obsolete ILEC Regulatory Obligations That Inhibit Deployment of Next-Generation Networks*, 29 FCC Rcd. 15644, ¶¶ 4, 56, 70 (rel. Dec. 18, 2014) (forbearing from a requirement that price cap carriers offer voice services in three types of census blocks, finding that price-cap carriers like AT&T will effectively become Lifeline-only ETCs *in the specific census blocks that are the subject of this forbearance*. As such, they must continue to offer voice telephone service to qualifying low-income households in those areas [*i.e.*, in those census blocks] unless or *until they relinquish their ETC designations in those areas* [*i.e.*, in those census blocks] pursuant to section 214(e)(4) (emphasis supplied); Memorandum Opinion and Order on Reconsideration, *Standing Rock Telecommunications, Inc. Petition for Designation as an Eligible Telecommunications Carrier*, 26 FCC Rcd. 9160, ¶ 11 (rel. June 22, 2011) (granting ETC designation for area including "rural partial wire centers"). Third Report and Order, Further Report and Order, and Order on Reconsideration, *In the Matter of Lifeline and Link Up Reform and Modernization*, 31 FCC Rcd. 3962, ¶ 48, 312 (rel. Apr. 27, 2016) (carving an exception to the phase-out of standalone voice obligations for ETCs "in those Census blocks where the ETC is the only Lifeline service provider in that given census block," which recognizes that ETC obligations can be defined at the census block level, and noting that ETCs taking advantage of FCC forbearance from certain requirements must "identify those areas by census block where they intend to avail themselves of this forbearance relief," which again recognizes that ETC obligations can vary by census block).

apply to the customer's existing AT&T service. AT&T noted that it also will send each remaining affected Lifeline customer a second notice letter and a bill message at least 15 days prior to the relinquishment date. AT&T maintained that all notices will inform each affected customer that a Lifeline discount can be obtained from the remaining ETCs in the area and will inform affected customers how to contact the Universal Service Administrative Company to obtain a list of other ETCs in the state and answer general questions about Lifeline. AT&T stated that these notice letters also will provide a list of Lifeline providers designated in all or part of AT&T's service territory in North Carolina and a link to an AT&T website that lists those ETCs by city/towns, based on publicly-available information. AT&T noted that Exhibit F attached to its Petition is a sample of the language of these letters and bill messages.

AT&T stated that to avoid customer confusion and assist with a smooth transition process, AT&T will stop enrolling customers from the relinquished area in the Lifeline program either five (5) days after the Commission issues an Order or on August 30, 2017, whichever is later. AT&T maintained that this approach, which is consistent with the approach taken in other jurisdictions, will prevent a newly enrolled Lifeline customer from having to change to another Lifeline provider shortly thereafter.[1]

AT&T requested that the Commission issue an order granting its Petition as soon as possible, but no later than July 31, 2017, so that AT&T can provide ample notice to its Lifeline customers prior to the relinquishment effective date of October 30, 2017.

INITIAL COMMENTS

The **Public Staff** noted in its comments that on December 15, 1997, the Commission designated AT&T as an ETC within its service area pursuant to 47 U.S.C. § 214(e)(1). The Public Staff stated that ETCs are eligible to receive federal universal service funding if they offer and advertise services as set out in 47 C.F.R. § 54.201(d) and meet universal service obligations, which include the deployment and maintenance of networks in rural and other high-cost areas and the provision of discounted services to eligible low-income consumers at discounted prices under the Lifeline Assistance Program (Lifeline).

The Public Staff commented that since AT&T's designation as an ETC, the FCC has restructured its universal service funding (CAF II) to focus more on the provision of broadband in high cost rural areas.[2] The Public Staff noted that this universal service funding is directed to census blocks rather than wire centers or service areas as in the past. The Public Staff maintained that recipients of CAF II funding must remain an ETC in the designated census blocks for six years and offer Lifeline to eligible customers. The Public Staff stated that, under CAF II, AT&T is eligible for universal service funding only in certain census blocks in its service area.

[1] AT&T customer service representatives handling Lifeline inquiries will be able to input a customer's address into a computer application that will determine whether the customer address is within the retained area.

[2] *See* Report and Order, Connect America Fund, 29 FCC Rcd. 15644 (2014); Report and Order and Further Notice of Proposed Rulemaking, Connect America Fund, 26 FCC Rcd. 17663 (2011) (subsequent history omitted).

The Public Staff observed that, in its Petition, AT&T noted that over the past eight years, its Lifeline customers have declined by 94% and that AT&T is serving less than 1% of Lifeline customers in North Carolina. The Public Staff commented that while AT&T does not seek to discontinue its offering of legacy voice service, its petition seeks the Commission's confirmation of its relinquishment of its ETC designation in the areas where it is not receiving CAF II support. The Public Staff noted that in the areas where AT&T would no longer be an ETC, it would discontinue offering Lifeline service.

The Public Staff stated that, under 47 U.S.C. § 214(e)(4), a state commission shall permit an ETC to relinquish its ETC designation in an area, as long as the area is served by more than one ETC. The Public Staff maintained that the ETC relinquishing its status must also give the state commission advanced notice of the relinquishment.

The Public Staff noted that AT&T stated in its Petition that the FCC has not addressed whether an ETC may relinquish portions of its service area or portions of wire centers, but allowing partial relinquishment of partial wire centers is consistent with CAF II's reliance on census blocks to determine eligibility for funding, as well as other FCC rulings.

The Public Staff stated that under 47 U.S.C. § 214(e)(2), state commissions have the primary responsibility for making ETC designations. The Public Staff commented that Section 214(e)(2) also specifies that before a commission designates an additional ETC for a service area, it must find that the determination is in the public interest. The Public Staff stated that the Commission made such a determination in designating Wilkes Communications, Inc., as an ETC in only certain wire centers by Order issued on April 21, 2016, in Docket No. P-100, Subs 133c and 133e. The Public Staff commented that, however, 47 U.S.C. § 214(e)(4) does not require a finding that the ETC relinquishment is in the public interest.

The Public Staff noted that as exhibits to its Petition, AT&T included a list of its current North Carolina ETC service area by wire center (Exhibit A); a list of the wire centers where it would retain ETC status (Exhibit B); a list setting out by wire center the number of Lifeline customers that would be retained, the number that would be relinquished, and the other ETCs designated in each of those wire centers (Exhibit C); a map showing the census blocks where AT&T would retain and relinquish ETC status (Exhibit D); information about mapping addresses in census blocks (Exhibit E); and a sample customer notice and bill message regarding the discontinuance of Lifeline service (Exhibit F).

The Public Staff commented that Exhibit C indicates that AT&T would relinquish 1,701 Lifeline customers and retain 91 Lifeline customers. The Public Staff stated that Exhibit C also shows that in each of those wire centers, there would be from four to seven designated competitive ETCs that provide Lifeline service. The Public Staff noted that five of these competitive ETCs are wireless carriers not under the Commission's jurisdiction. The Public Staff further noted that the remaining two offer Lifeline service via landline in each of the wire centers where AT&T would relinquish Lifeline customers.

Additionally, the Public Staff noted that on October 14, 2011, AT&T filed a letter of election pursuant to G.S. 62-133.5(m) in Docket No. P-55, Sub 1013m. The Public Staff commented that by this election, AT&T indicated that it would forgo receipt of any funding from a State funding mechanism other than interconnection rates that support universal service funding and that its territory was open to competition, thereby deregulating Commission oversight over the rates, terms, and conditions for AT&T's services, except for certain issues or topics reserved under the Commission's jurisdiction. The Public Staff noted that G.S. 62-133.5(m)(3)c. provides that the Commission's jurisdiction over the Lifeline program "consistent with Federal Communications Commission rules and relevant orders" of the Commission was not affected.

The Public Staff stated that it believes that AT&T has met the conditions precedent set out in 47 U.S.C. § 214(e)(4) for it to relinquish its ETC status, *i.e.*, it has shown that there is more than one ETC in the service area and has provided advance notice to the Commission.[1] Further, the Public Staff noted that while the Commission retains jurisdiction over Lifeline, this jurisdiction must be consistent with FCC rules and Commission orders. The Public Staff stated that it is not aware of any orders or rules that would prohibit AT&T from relinquishing its ETC designation.

The Public Staff commented that AT&T has indicated in its Petition that requests to relinquish ETC status in portions of its service area have been granted in Alabama, Illinois, Kentucky, Mississippi, Missouri, South Dakota, Tennessee, Washington, and Wisconsin. The Public Staff further noted that counsel for AT&T has indicated to the Public Staff that to his knowledge, no request has been denied.

The Public Staff stated that it appears that all of AT&T's affected Lifeline customers that require or prefer landline service should have two wireline carriers to choose from that are under the Commission's jurisdiction. The Public Staff further noted that there also appears to be at least two wireless carriers in each affected wire center that provide Lifeline service; however, these carriers are not subject to Commission oversight. The Public Staff commented that the universal service rules do not appear to treat wireless and wireline carriers differently, but the Public Staff is aware of some areas of North Carolina where cellular service is not available.

The Public Staff noted that under 47 U.S.C. § 214(e)(2) and (3), the FCC or a state commission may designate a common carrier as an ETC, especially for unserved areas. The Public Staff stated that under this authority, the Public Staff believes that the Commission could determine whether an ETC should be designated should these census blocks become unserved by other ETCs or if eligible Lifeline customers are unable to access cellular service.

[1] The second sentence of 47 U.S.C. § 214(e)(4) contains requirements for carriers that are relinquishing ETC status and ceasing to provide universal service pursuant to 47 U.S.C. § 254(c). AT&T stated that it will continue to provide universal service in the areas in which it seeks to relinquish ETC designation, so the requirements of this sentence are not applicable in this case.

The Public Staff commented further that Commission Rule R21-2 sets out certain requirements for local exchange carriers such as AT&T intending to cease operations or to discontinue or reduce the provision of telecommunications services. The Public Staff stated that in this case, the Public Staff believes that AT&T's plan to discontinue Lifeline service to the 1,701 customers constitutes a reduction in service under Commission Rule R21-2.

The Public Staff noted that Commission Rule R21-2(a) sets out the requirements for a petition to discontinue or reduce service. The Public Staff opined that AT&T's Petition complies with these requirements. The Public Staff stated that in compliance with Commission Rule R21-2(b), AT&T has indicated that it will provide affected customers with at least 60 days' notice. The Public Staff further noted that Commission R21-2(c) requires that AT&T provide on the notice and on its website a toll-free number for affected customers to call for information. The Public Staff noted that the proposed notice attached as Exhibit F to the Petition indicates that AT&T will include a toll-free number and that AT&T's website at www.att.com lists a toll-free number for customers to call for information.

The Public Staff noted that it has reviewed the proposed customer notice and bill message and recommends that the Commission find them to be sufficient pursuant to Commission Rule R21-2(d). Further, the Public Staff noted that AT&T has agreed to meet with the Public Staff's Consumer Services Division prior to sending out notice to customers of its intention to discontinue offering Lifeline service in their census block.

In conclusion, the Public Staff stated that it does not oppose the granting of AT&T's Petition. The Public Staff requested that the Commission require AT&T to: (1) notify the Commission both when it has mailed or transmitted notice to customers and when it terminates Lifeline service; (2) within seven days of Commission approval of the Petition, post on its website information to assist Lifeline customers to migrate to other Lifeline carriers in compliance with Commission Rule R21-2(f); and (3) within seven days of receiving Commission approval, file a spreadsheet containing a list of billing names, addresses, and telephone numbers (or circuit numbers for non-switched services) for all customers affected by the discontinuation, except those with non-published numbers, as well as circuit IDs, cable pair identification and a statement that AT&T will fully cooperate in the transfer of numbers to other providers through the Number Portability database pursuant to Commission Rule R21-2(g).

REPLY COMMENTS

AT&T noted in its reply comments that the only party to comment on AT&T's Petition was the Public Staff. AT&T also noted that the Public Staff raised no objections to the Commission granting AT&T's request. AT&T commented that the Public Staff specifically stated that it believes that AT&T has met the conditions precedent set out in 47 U.S.C. §214(e)(4) for AT&T to relinquish its ETC status. AT&T also noted that the Public Staff stated that it is not aware of any orders or rules that would prohibit AT&T from relinquishing its ETC designation. AT&T maintained that the Public Staff also does not have any issues with the manner in which AT&T will notify its customers that the Lifeline discount will no longer be available in the relinquishment area, finding AT&T's proposed customer notice and bill message to be sufficient pursuant to Commission Rule R21-2(d).

AT&T stated that its reply comments briefly address the Public Staff's initial comments regarding Commission Rule R21-2(d). AT&T asserted that, as purely a technical matter, AT&T does not agree with the Public Staff's suggestion that Rule R21-2 applies to its ETC relinquishment. AT&T stated that this is not because AT&T has issues with the rule or is unwilling to comply, but rather because, as AT&T understands the rule, it does not apply under these circumstances. AT&T maintained that by their own terms the Chapter 21 rules govern both the complete cessation of telephone operations and the discontinuance or reduction of telephone service by local exchange companies. AT&T argued that in this instance, however, AT&T is not discontinuing or reducing any legacy voice service, and AT&T's ETC relinquishment will not affect the availability of any AT&T legacy voice service in any area of the State. AT&T maintained that in North Carolina, Lifeline is not a service per se, but instead it is a discount that applies to any eligible voice or broadband service ordered by qualifying low-income customers. AT&T noted that its General Subscribers Services Tariff states that "Lifeline service is a federally administered program providing a monthly discount to qualifying low-income consumers for voice telephone service or broadband service." AT&T asserted that all customers who want to continue using AT&T services will be able to do so. AT&T maintained that the only impact of AT&T's ETC relinquishment is that AT&T will no longer provide a Lifeline discount to customers in the relinquishment area. AT&T argued that there is no "cessation" or "discontinuance" of any AT&T telephone service – only the elimination of a discount.

AT&T noted that without waiving its forgoing comments, AT&T agrees with the Public Staff that if Commission Rule R21-2 did apply, the ample notice and information AT&T is giving the Commission and its affected customers regarding the ETC relinquishment and the elimination of the Lifeline discount in the relinquishment area would comply with the Rule. AT&T stated that the Rule requires at least 45 days' notice to the Commission, and AT&T filed its Petition on May 2, 2017, to become effective on October 30, 2017, which is nearly six months after the filing date. AT&T also noted that the Rule asks for a service description and the number of customers affected. AT&T maintained that its Petition, in Exhibit C, states that 1,701 customers in the relinquishment area will no longer be eligible for a Lifeline discount from AT&T, however, they are free to obtain it from another ETC. AT&T further noted that the Rule requires a description of the customer notification efforts that will be used. AT&T stated that its Petition provides the actual customer notification language it will use and describes when and how it will be provided to affected customers.

In addition, AT&T stated that the Rule requires that customers receive at least 14 days' notice and that AT&T's Petition states that customers will receive at least a 60 days' notice. AT&T noted that the Rule asks the carrier to provide a reason for the discontinuance. AT&T noted that its Petition describes in detail the reasons why AT&T no longer wants to be an ETC in the relinquishment area, including that AT&T lost more than 94% of its Lifeline subscribers between 2008 and 2016 to the multiple other ETCs that offer the Lifeline discount. AT&T further stated that the Rule directs carriers to make available a toll-free number where customers can reach knowledgeable customer service representatives. AT&T stated that its customer notice accomplishes both of those objectives.

AT&T continued that the Rule states that the carrier may not take action until the Commission issues an order. AT&T maintained that it will not eliminate the Lifeline discount in the relinquishment area until after the Commission issues an order addressing its Petition. AT&T further commented that the Rule directs the carrier to post relevant information on its website. AT&T maintained that with one slight modification to the Public Staff's recommendation, which the Public Staff has indicated is acceptable, AT&T will be doing just that prior to mailing out the customer notice, and the link will appear in the customer notice. AT&T stated that the Public Staff initially recommended that AT&T post the relevant information on its website within seven days of a Commission Order approving the relinquishment, but after further discussion with AT&T, the Public Staff has agreed to a slight modification of its recommendation. AT&T maintained that anticipating the Order could be issued several weeks before AT&T actually mails notice to the affected Lifeline subscribers, AT&T proposes that, as AT&T is doing in other states, AT&T be permitted to post the information a short time prior to mailing out the customer notice. AT&T stated that Counsel for the Public Staff has indicated that arrangement is acceptable.

AT&T noted that the Rule also asks for a list of affected customers. AT&T stated that shortly after AT&T puts its customer notification letters in the U.S. Mail, it will provide the Commission with a confidential listing of the customers receiving the notice. AT&T stated that Commission Rule R21-2(g) provides that, in instances where carriers are ceasing operations and discontinuing all services, the carrier must provide the Commission with a list of affected customers within seven days of the Commission's approval of the discontinuance. AT&T argued that, here, however, AT&T is not discontinuing any service, only eliminating a discount. AT&T stated that it will be notifying its remaining Lifeline subscribers in the relinquishment area at least 60 days before the October 30, 2017 effective date that the Lifeline discount will no longer be available from AT&T. AT&T maintained that it will provide the Commission a confidential listing of the affected customers who receive that notice, including billing address and phone number, and will do so within seven days of the mailing date.

Finally, AT&T noted that the Rule directs the carrier to cooperate in transferring the telephone numbers of affected customers who elect to move to another carrier by providing the requisite information to the Number Portability database. AT&T stated that that is AT&T's standard practice for moving customer numbers to other carriers.

AT&T concluded that, given that the Public Staff agrees AT&T has met the legal requirements for ETC relinquishment, that no other party has submitted comments or objections, and that AT&T will be providing ample advance notice to all affected customers and otherwise complying with the terms of Commission Rule R21-2 (even though, as a technical matter, that rule does not apply here), AT&T renews its request that its unopposed Petition should be granted as soon as practicable.

DISCUSSION AND CONCLUSIONS

The Commission notes that the Public Staff was the only party to file initial comments on AT&T's Petition. The Public Staff did not oppose the Commission granting AT&T's Petition.

In addition, the Commission concludes that because AT&T has agreed to adhere to the requirements outlined in Commission Rule R21-2, it is not necessary for the Commission to determine whether the Rule is applicable to the situation addressed in AT&T's Petition.

Based on a thorough review of AT&T's Petition, the initial comments, the reply comments, and the record proper, the Commission agrees with the Public Staff that AT&T has met the requirements of 47 U.S.C. § 214(e)(4) for AT&T to relinquish its ETC status in a portion of its service area in North Carolina, as outlined in the Petition, effective October 30, 2017. The Commission also is not aware of any orders or rules that would prohibit AT&T from relinquishing its ETC designation as requested in AT&T's Petition.

Therefore, the Commission concludes that it is appropriate to grant AT&T's Motion and confirm AT&T's relinquishment of its ETC designation in the census blocks outlined in AT&T's Petition, effective October 30, 2017. The Commission further concludes that AT&T's proposed customer notification plans including the sample customer notice and bill message are sufficient.

The Commission further finds it appropriate to adopt the recommendations of the Public Staff, as subsequently modified as outlined in AT&T's reply comments. Thus, AT&T is hereby required to: (1) notify the Commission, in writing in Docket Nos. P-55, Sub 1934 and P-100, Sub 133c, both when it has mailed or transmitted notice to customers and when it terminates Lifeline service; (2) within a short time prior to mailing out the customer notice, post on its website information to assist Lifeline customers to migrate to other Lifeline carriers; and (3) within seven days of the customer notice mailing date, file a spreadsheet containing a list of billing names, addresses, and telephone numbers for all customers affected by the relinquishment.

Finally, as noted by the Public Staff in its initial comments, AT&T has agreed to meet with the Public Staff's Consumer Services Division prior to sending out notice to customers of its intention to discontinue offering Lifeline service in their census block.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the __14th__ day of June, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

TRANSPORTATION -- COMMON CARRIER CERTIFICATE

DOCKET NO. T-4642, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Dominic Edward Ortiz-Brown, d/b/a Charlotte Veteran Movers, 1920 Arbor Vista Drive, Charlotte, North Carolina 28262 - Application for Certificate of Exemption to Transport Household Goods	)))))	NOTICE OF DECISION

BEFORE: Commissioner Bryan E. Beatty, Presiding; Commissioners Don M. Bailey and James G. Patterson

BY THE COMMISSION: On September 16, 2016, Dominic Ortiz-Brown, d/b/a Charlotte Veteran Movers (Applicant) filed with the Commission an application for a certificate of exemption to transport household goods pursuant to North Carolina General Statute Chapter 62, Article 12 and Commission Rule R12-8.1. After notice to Applicant, an evidentiary hearing was held on January 5, 2017, in Raleigh, North Carolina, to address the Commission's concerns regarding Mr. Dominic Edward Ortiz-Brown's fitness. Contemporaneously with the issuance of this Notice of Decision, the Commission issued a confidential Order Ruling on Fitness finding and concluding that the application filed by Dominic Edward Ortiz-Brown, Applicant's sole principal, **should be denied** for failure to establish that he is fit to operate in this State as a household goods mover.

The Commission's decision in this matter is based on the testimony and exhibits submitted to the record, including Mr. Ortiz-Brown's criminal history record. Pursuant to G.S. 62-273.1 and G.S. 143B-963, the Commission must maintain the confidentiality of Mr. Ortiz-Brown's criminal history record. Therefore, the confidential Order Ruling on Fitness issued in this docket will only be made available to the Applicant.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of June, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. T-4622, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Calvin Eugene Walker, d/b/a Walker's Movers, 1825-B Franciscan Terrace, Winston-Salem, North Carolina 27127 – Application for Certificate of Exemption to Transport Household Goods	)	ORDER RULING ON FITNESS TO OBTAIN CERTIFICATE OF EXEMPTION

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina, on Wednesday, July 12, 2017, at 10:00 a.m.

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Commissioners James G. Patterson and Lyons Gray

APPEARANCES:

For Calvin Eugene Walker, d/b/a Walker's Movers:

Calvin Eugene Walker, 1825-B Franciscan Terrace, Winston-Salem, North Carolina 27127, pro se

BY THE COMMISSION: On January 31, 2017, Calvin Eugene Walker, d/b/a Walker's Movers (Applicant), pursuant to G.S. 62-261.8(1) and Commission Rule R2-8.1, filed an application with the Commission for a certificate of exemption (certificate) to transport household goods by motor vehicle for compensation within North Carolina. Mr. Calvin Eugene Walker is identified as the Applicant's sole owner. Mr. Walker's fingerprint card was also included with the application so that the Commission could request the State Bureau of Investigation (SBI) to provide a certified criminal history record check as required by G.S. 62-273.1 and Commission Rule R2-8.1(a)(3).

On May 30, 2017, the Commission issued an Order Scheduling Application for Hearing requiring the Applicant to appear before the Commission to discuss the application. The Order also provided that the Public Staff of the North Carolina Utilities Commission (Public Staff) may participate in the hearing on behalf of the using and consuming public.

On June 27, 2017, Lucy E. Edmondson, Staff Attorney with the Public Staff, filed a letter in this docket informing the Commission that the Public Staff did not intend to participate in this proceeding.

On July 12, 2017, the hearing was held in Raleigh, as scheduled. Calvin Eugene Walker, Applicant's owner, appeared and testified pro se in support of the application and responded to questions from the Commission.

Based upon the information contained in the application, the testimony received at the hearing, and the entire record in this matter, the Commission makes the following:

FINDINGS OF FACT

1. On January 31, 2017, the Applicant filed an application with the Commission for a certificate to transport household goods by motor vehicle for compensation within North Carolina. Calvin Eugene Walker is the sole owner of the business located at 1825-B Franciscan Terrace in Winston-Salem, North Carolina. The Applicant is properly before the Commission seeking a certificate of exemption pursuant to G.S. 62-261(8) and Commission Rule R2-8.1.

2. The Applicant started working in the moving business when he was 21 years old in or around 1982. He first began working for United Van Lines (United) in High Point, North Carolina, where he drove, loaded/unloaded furniture and other items. When United changed its name to Atlas Van Lines (Atlas), Applicant remained with the business and his responsibilities did not change. The Applicant worked for the two companies a total of fourteen and one half years.

3. The Applicant left Atlas to work at Lee Jeans Apparel (Lee) as a machine operator. He worked at Lee for two years before moving on to Douglas Battery (Douglas) which paid him more money. He was eventually laid off by Douglas when the company closed down.

4. While working at Douglas, the Applicant secured a part-time job with U-Haul. Applicant was affiliated with U-Haul as a helper for two years before deciding to return to moving full-time.

5. The Applicant formed his own moving business in 2011 as Walker's Professional Movers. The name of the business was later changed to Walker's Movers. The company served as a U-Haul moving helper and initially delivered furniture for customers from different furniture stores throughout the Winston-Salem area.

6. The Applicant performed several household goods moves until he was contacted by the Public Staff by telephone and informed that intrastate household goods moves for compensation without a certificate from the Commission were illegal. The Applicant subsequently filed the instant application with the Commission.

7. The Applicant employs two part-time workers to perform loads and moves.

8. The Applicant has had no complaints lodged against him with the Public Staff regarding damaged property or regarding his service fee. He has had some issues with fulfilling moves. He has had to cancel two moves because an employee did not show up for the job.

9. The Applicant has a Chevrolet Express Van and a 20-foot trailer to utilize in his moving operations.

10. The Applicant testified he is compliant with state tax laws and requirements. He pays his employees on time.

11. The Applicant appeared at the July 12, 2017 hearing and satisfactorily answered the Commission's questions concerning the application and Mr. Walker's background and fitness to be a certificated household goods mover in North Carolina.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

The evidence in support of the findings of facts is found in the testimony of Mr. Calvin Eugene Walker and the application, which was admitted as an exhibit at the hearing. The record shows that the Applicant possesses a total of fourteen and one half years of experience in the trucking and moving industry. His experience began when the Applicant was 21 years old.[1] At that time, he began working with United Van Lines (United) in High Point, North Carolina.[2] At United, he drove, loaded and unloaded furniture and other items, and packed the moving trucks.[3] He had minimal contact with customers after a moving assignment was accepted, other than to greet the customers as he performed his responsibilities on moving day. He worked at United for two years before it was renamed Atlas Van Lines (Atlas).[4] He continued to work under the Atlas' name for another twelve and one half years.[5] His responsibilities remained the same under Atlas.

The Applicant eventually left the moving business and decided to relocate from High Point to Winston-Salem, North Carolina, to try another profession.

The Applicant began working for Lee Jeans Apparel (Lee) where he operated machines.[6] After two years at Lee, he left to work at Douglas Battery (Douglas), where he was paid more for his labor. He was at Douglas for two years where he also operated machinery.[7] While at Douglas, he sought to increase his income by securing a part-time job with U-Haul where he helped customers who needed assistance with their rented trucks.[8] At U-Haul, he also cared for rental equipment and secured reservations. He held this part-time job with U-Haul for several years. When Douglas closed its doors and laid-off its employees in 2009,[9] the Applicant was forced to apply for unemployment benefits and rely on his income from his part-time U-Haul job.

In search of more income, the Applicant decided to return to the moving business full-time. In 2011, the Applicant formed his own moving business.[10] He initially named it Walker's Professional Movers and later changed its name to Walker's Movers.[11] The business started out

[1] Hearing Transcript p. 8.

[2] *Id.*

[3] *Id.* at 9.

[4] *Id.*

[5] *Id.* at 8-9.

[6] *Id.* at 8 & 43.

[7] *Id.* at 8.

[8] *Id.* at 11.

[9] *Id.*

[10] *Id.* at 14.

[11] *Id.* at 14.

as a mover's helper, assisting U-Haul customers who needed help with a move or assistance with their trucks. Applicant's business also offered delivery services from different furniture stores in the area. The Applicant testified that he had performed a few household goods moves until he was contacted by the Public Staff three summers ago and advised that household goods movers were required by law to be certificated by the Commission.[1] As a result of this information, the Applicant ceased performing any household goods moves and contemplated filing an application for a certificate from the Commission to become a full household goods carrier.[2] The Applicant asserts that he is prepared to secure the necessary insurance required of a certified household goods carrier.

While the Applicant has participated in various moving activities throughout the years, there is no evidence that any complaint has ever been filed against him with the Public Staff. The Applicant has two part-time employees that help with the businesses activities.[3] He testified that his employees handle all aspects of the trucks including loading and unloading furniture and other items.[4] The Applicant, himself, handles customers when they call to schedule appointments.[5]

The Applicant further testified that he has had no complaints involving broken furniture or disputes over the price of his services.[6] According to the Applicant, the only complaints lodged against him involved his availability for service.[7] Unfortunately, the Applicant has had to cancel two moves because an employee did not show up for work.[8] However, on the limited occasions when this has occurred, the Applicant has tried to assist the customer by finding another company to perform the move.

The Applicant appears to be serious and diligent about helping his customers have a good moving experience. If there is a problem, the Applicant's testimony demonstrates that he is committed to resolving it promptly. If he cannot complete or fulfill a move, he tries to work with the customer to find someone else.[9] Also, if he performs a move and there is any damage, his preference is to resolve the dispute quickly.[10] To avoid arguing with customers, he is willing to replace any damaged item, have someone come out and fix the item, or otherwise work it out to the satisfaction of the customer.

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[1] *Id.* at 15.

[2] *Id.*

[3] *Id.*

[4] *Id.*

[5] *Id.*

[6] *Id.* at 19.

[7] *Id.* at 18-19.

[8] *Id.*

[9] *Id.* at 18.

[10] *Id.* at 19.

The record further shows that the Applicant has the resources necessary to perform small household goods moves. The Applicant testified that he owns a Chevrolet Express Van and a 20-foot trailer which he currently uses to haul furniture from furniture stores to customers' residences.[1] The Applicant is prepared to secure the necessary insurance required of a certificated carrier.[2] In order to properly estimate and bill the moves he performs, the Applicant is prepared to attend a Maximum Rate Tariff (MRT) training.[3] The Applicant recognizes that this is something that may help him serve his customers.

The Applicant also has a plan to market his business' services to the using and consuming public. He intends to advertise by taking advantage of websites such as Craig's list, and word of mouth to customers for whom he delivers furniture from furniture stores.[4] He also intends to associate with U-Haul as moving helpers for rental customers.[5]

The Commission has reviewed the Applicant's application, his background, his criminal history record check, work history, and his testimony provided under oath and finds that he has answered the Commission's questions regarding his background, experience, and interest in the household goods moving business to the Commission's satisfaction.

Based upon the foregoing, the Commission finds and concludes that Calvin Eugene Walker, d/b/a Walker's Movers has shown to the satisfaction of the Commission that he has adequate knowledge of the household moving industry, has a demonstrated ability to follow the statutes and Commission rules, and has a desire to provide satisfactory service to the using and consuming public. He appeared before the Commission and satisfactorily answered the Commission's questions concerning his application as well as his background and fitness to be a certificated household goods mover in North Carolina. Therefore, having considered the application and all evidence of record, the Commission finds and concludes that the issue of Mr. Walker's fitness **should not preclude** him from being granted a certificate of exemption.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of September, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

[1] *Id.* at 20.

[2] *Id.* at 16.

[3] *Id.* at 16.

[4] *Id.* at 44.

[5] *Id.*

DOCKET NO. T-4657, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of All My Sons of South Raleigh, Inc.,	)	
For Amendment of the Maximum Rate Tariff –	)	ORDER REQUESTING
To Allow Electronic Bill of Lading	)	COMMENTS ON PETITION

BY THE COMMISSION: On March 29, 2017, All My Sons of South Raleigh, Inc., (AMS) filed a petition with the Commission requesting that the Commission adopt a transition to include electronic bill of lading (BOL). In its petition, AMS asserted that it has successfully implemented the electronic BOL in many states where it operates. Additionally, AMS contended that it has already structured BOL electronic document and signature processes led by top tier customer driven delivery and regulatory entities such as Federal Express (FedEx), United Parcel Service (UPS), United States Postal Service (USPS), and Federal Motor Carrier Safety Administration (FMCSA). AMS stated that this technology has been designed to meet the existing Commission requirements assuring compliance with the rates and tariff requirements programmed into each required BOL field.

In support of its petition, AMS stated that the benefits of electronic BOL would be the following:

- Assurance of consumers understanding prior to move [of] all information and terms. Verification step by step through initials or signatures not possible with paper forms.

- This electronic document fully replicates the existing NCUC paper requirements & "core functions" as a receipt, evidence of or containing the contract of carriage, terms and as a document of title.

- Customer signs all Bills of ladings and all docs and addendums required pre-post move.

- No credit card imprints, card swiped onsite for charges, customer must sign in person and acknowledge.

- Exact duplicates of moving docs signed th[r]ough automated email "real time" to customer and AMS servers.

- All parties can print bill of lading & supporting documents in order "On Demand" easy access for any party.

- Process assures Driver and Consumer compliance to protect all parties "pre-move".

- Eliminates lost or non-duplicate documents, each BOL is true record of move day for each party.

- Validates agreement of driver start and stop times, weights, miles, estimate and copies customer "Real Time".

- Customer can clearly review all terms and charges prior to move and prior to delivery receipt.

- Customer has ability to request paper BOL.

WHEREUPON, the Commission finds good cause to request comments on the petition filed by AMS from interested members of the household goods moving industry, the Public Staff, and other interested entities. The Commission seeks comments on all issues relevant to the electronic BOL proposal as described in AMS' petition; at a minimum, the following issues should be addressed:

(1) Whether the MRT should be amended by the Commission to allow household goods movers to use electronic BOLs, as an alternative for the existing Commission-approved paper BOLs which satisfy BOL requirements as detailed in the MRT; and if so, how should the MRT be modified;

(2) How should the instructional booklet "Moving 101 – A North Carolina Consumers' Guide" be modified to explain electronic BOL process;

(3) Describe the level of computer savvy and the basic equipment or technology that is needed by the shipper to access electronic BOLs;

(4) Whether the electronic BOL will have the same appearance as the current paper BOLs that are currently in use and, if not, what are the differences and what, "core functions" will be missing if any;

(5) What will the persons transporting the goods be required to have in their possession for transporting the household goods, i.e., what are the required electronic devices;

(6) If a mover is stopped by the State Highway Patrol (SHP), during the transportation of a shipper's household goods, how will the electronic BOL (i.e., Paperless Version of BOL) be provided to the SHP as proof that the carrier has received the goods from the shipper and has authority for the transport of such goods;

(7) What protocols will need to be implemented and followed to keep the personal details and electronic signatures secure and safe from cyber-attacks and abuse or misuse by cyber thieves; and

(8) What back up and retention polices will your company implement for keeping the electronic BOLs, and backing up the system, i.e. rules regarding the length of retention when the document is stored? If a customer requests an electronic BOL of their move from multiple number of years ago, will your company be able to provide the BOL?

Furthermore, those who file comments may address any other relevant issues in their comments in addition to those set forth above.

IT IS, THEREFORE, ORDERED as follows:

1. That interested parties may file comments with the Commission on or before August 18, 2017, and that interested parties may file reply comments on or before September 4, 2017 on whether the MRT should be amended by the Commission to allow household goods movers to utilize electronic BOL as described in AMS' petition.[1]

2. That the Chief Clerk shall mail a copy of this Order to all holders of a certificate of exemption to transport household goods granted by the Commission, all applicants with pending applications seeking certificates of exemption, the Public Staff, the Attorney General, and the North Carolina Movers Association, Inc.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of July, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

Commissioner Daniel G. Clodfelter did not participate in this decision.

[1] The official files in this docket may be viewed on the Commission's website. Go to www.ncuc.net, then select "Docket Portal", "Docket Search", and then enter in the "Docket Number" box: T-4657 Sub 1.

DOCKET NO. T-4626, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Harvey's Moving Company, LLC, 200 West Ash Street, Suite 205, Goldsboro, North Carolina 27530 – Unauthorized Representation and Unauthorized Transportation of Household Goods	))))	ORDER RULING ON SHOW CAUSE AND ASSESSING CIVIL PENALTIES

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina, on Wednesday, December 7, 2016, at 10:00 a.m.

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Commissioners Bryan E. Beatty and Jerry C. Dockham

APPEARANCES:

For Harvey's Moving Company, LLC

Charles R. Gurley, Esq., Law Office of Charles R. Gurley, P.A., 104-B South William Street, Post Office Box 1703, Goldsboro, North Carolina 27533-1703

BY THE COMMISSION: On April 1, 2016, an application for a certificate of exemption (certificate) to transport household goods (HHG) by motor vehicle for compensation within North Carolina was filed with the Commission on behalf of Harvey's Moving Company, LLC (Harvey's Moving or Applicant), pursuant to G.S. 62-261(8) and Commission Rule R2-8.1. The application, filed in Docket T-4626, Sub 0, lists Bobby D. Harvey, Robert Boswell, Bobby R. Harvey and Jennifer Pitts as principals of the Applicant.

On June 20, 2016, in Docket No. T-4626, Sub 0, the Commission issued Order Scheduling Application for Hearing in Raleigh, North Carolina to address questions resulting from its review of the complete application regarding the Applicant's fitness to obtain a certificate with Bobby D. Harvey as a principal. The hearing was scheduled for August 15, 2016.

On August 15, 2016, Charles Gurley notified the Commission that he would represent the Applicant in the hearing and asked for a continuance due to a conflict with his Superior Court trial schedule. The motion to continue was granted by Commission Order the same day.

Having become aware of information suggesting that the Applicant was advertising its services to the public and performing full service moves of HHG in the state of North Carolina for compensation without first obtaining a certificate of exemption to transport HHG from the Commission, the Presiding Commissioner issued Order Providing Notice of Show Cause in Docket No. T-4626, Sub 1. The Order required the Applicant to appear and show cause why it should not be found to (1) have advertised its services to the using and consuming public as holding a certificate and otherwise authorized to operate as a carrier of household goods in North Carolina in violation of G.S. 62-280.1(a); (2) have performed an intrastate transportation move of HHG for compensation in North Carolina without a certificate of exemption, as required in G.S. 62-261(8) and Commission Rule R2-8.1; and, therefore, be subject to sanctions provided by statute, including monetary penalties levied by the Commission and/or suspension of its license plates.

By Order of the Presiding Commissioner issued on September 7, 2016, Dockets T-4626, Subs 0 and 1 were consolidated for hearing, which was re-scheduled by the same Order for October 13, 2016. The Order also provided the Applicant with notice that it could be assessed a civil penalty for each violation of North Carolina law and/or Commission Rules and that such penalties would be subject to recovery pursuant to G.S. 62-280.1 and G.S. 62-312.

The consolidated proceedings came on for hearing on October 13, 2016, as scheduled. Bobby D. Harvey ("Mr. Harvey") appeared and informed the Commission that it was uncertain whether Applicant's attorney would be able to attend the hearing due to the effects of Hurricane Matthew[1] and related flooding in the Wayne County area. Mr. Harvey reported that he had not been in contact with Mr. Gurley subsequent to the hurricane's impact on the area. When Mr. Gurley did not appear, the hearing was continued based on the representations of Mr. Harvey.

Later the same morning, Mr. Gurley caused email notice to be filed with the Commission indicating that he was unable to travel to the hearing due to flooding caused by the hurricane. He requested that the Commission reschedule the hearing. By Order dated October 20, 2016, the Commission re-scheduled the hearing for December 7, 2016, in Raleigh, North Carolina.

The hearing was held on December 7, 2016, as scheduled. The Applicant and Mr. Harvey appeared and were represented by counsel, Mr. Gurley.

On January 4, 2017, the Applicant filed its proposed order.

Based upon the testimony of and the exhibits presented at the hearing, and the entire record in these proceedings, the Commission makes the following:

FINDINGS OF FACT

1. The Commission has jurisdiction over public utilities, including those engaged in the intrastate transportation of household goods for compensation in North Carolina, as defined by G.S. 62-3(27) and (15). Movers of household goods in North Carolina must obtain a certificate pursuant to G.S. 62-261(8) and Commission Rule R2-8.1 prior to performing any intrastate residential move for compensation.

[1] Hurricane Matthew hit the state of North Carolina on or about October 8, 2016, causing flooding in various parts of the state, including Wayne County, as well as power outages due to fallen trees on power lines.

2. On April 1, 2016, Applicant, pursuant to G.S. 62-261(8) and Commission Rule R2-8.1, filed an application with the Commission for a certificate to transport household goods by motor vehicle for compensation within North Carolina.

3. The Applicant is properly before the Commission, pursuant to Commission Rules R2-8.1 and R1-4(3).

4. As of the date of the hearing, Applicant was not a certificated intrastate mover of household goods for compensation.

5. Applicant and one of its principals, Bobby D. Harvey received a letter dated April 4, 2016 from the Commission, stating that "until such time as you have been granted a certificate of exemption by the Commission, it is unlawful for you to orally, in writing, in print, or by sign, including the use of a vehicle placard, phone book, Internet, magazine, newspaper, billboard, or business card, or in any other manner, directly or by implication, represent yourself as holding a certificate or being otherwise authorized to operate as a household goods mover in North Carolina."

6. The Applicant advertised its services on the back of receipts from Harris Teeter on Wayne Memorial Drive in Goldsboro, North Carolina, from July 26, 2016, through at least November 2016. The advertisements included Applicant's business name, street address and phone number as well as coupons offering $50 off for a move of $500 or more and $200 off for moves identified as Elite Package Moving and Cleaning. Beneath Applicant's name was the phrase,"Quality Moving With Friendly Customer Service." These receipt advertisements did not indicate in any way that Applicant's moving services were limited or that Applicant was not authorized to perform full service intrastate HHG moves. The advertisements did not expressly state or claim that Applicant was a licensed HHG mover.

7. In September 2016, advertising for the Applicant's services was published in *The Goldsboro News-Argus*, a local newspaper. Mr. Harvey placed the newspaper ad, which ran regularly in the *News-Argus* at least through November 2016. The advertisement appeared as a replication of the Applicant's business card. It contained Applicant's name (Harvey's Moving Company), Mr. Harvey's name as the owner, a reference to membership in the Wayne County Chamber of Commerce, Applicant's address, phone numbers, an email address, and the Applicant's website. Under Applicant's name was the motto, "Quality Moving with Friendly Customer Service." The newspaper "business card" advertisement did not indicate in any way that the Applicant's moving services were limited or that Applicant was not authorized to perform full service intrastate HHG moves. The advertisement also did not expressly state or claim that the Applicant was a licensed HHG mover.

8. In an October 2016 edition of *go! Wayne County*, which Mr. Harvey described as an insert publication of the *Goldsboro News-Argus,* Applicant's services were advertised. The print ad stated, among other things, that Applicant provided commercial and residential relocation services. Mr. Harvey testified that he believes the *go! Wayne County* ads were a part of a

complimentary package of publishing services he received for purchasing the "business card" ad with the *News-Argus*. Mr. Harvey further testified that he did not specifically provide information for nor was he asked to proof or review the *go! Wayne County* ad. He testified he believes the insert publication obtained information for the ad from the newspaper's knowledge of the Applicant's business and from the Applicant's business card, Facebook page and website. Mr. Harvey either provided or was responsible for the moving information on Applicant's business card. Similar moving information was provided to the *News-Argus* for publication as well as used on the Applicant's Facebook page and Applicant's website. The *go! Wayne County* advertisement did not indicate in any way that the Applicant's moving services were limited and that Applicant was not authorized to perform full service intrastate HHG moves. The advertisement also did not expressly state or claim that the Applicant was a licensed HHG mover.

9. Mr. Harvey acknowledged that he has advertised/promoted Applicant's moving services in print media and online through Applicant's internet website and Facebook page. Applicant's website (www.harveysmovingcompany.com), at the time of the hearing, asked those visiting the site whether they were "moving across town?" or "moving to the next bigger city?"

10. As of the date of the hearing, Applicant was still advertising its moving services through print media, its website and its Facebook page.

11. Applicant violated G.S. 62-280.1 when it advertised as a mover in the local newspaper, on the back of the Harris Teeter grocery receipts, on business cards, and on the company's website and Facebook page.

DISCUSSION OF EVIDENCE AND CONCLUSIONS[1]

TRANSPORTATION OF HOUSEHOLD GOODS IN INTRASTATE COMMERCE

Aware that Applicant appeared to be advertising its moving services in print and online media and that customer testimonials and reviews of Applicant were also online, the Commission ordered Applicant to show why it should not be found to have acted as a de facto public utility by holding itself out as a common carrier of HHG or have performed an intrastate HHG move for compensation in violation of G.S. 62-261(8) and Commission Rule R2-8.1. After receiving Mr. Harvey's testimony at the hearing and after reviewing the record as a whole, the Commission concludes that the record does not support a finding that Applicant has performed any intrastate move for compensation prior to obtaining the required certificate of exemption.

[1] Docket Nos. T-4626 Sub 0 & 1 were consolidated for hearing. However, disposition of T-4626, Sub 0 on the issue of fitness is addressed by confidential order of the Commission issued simultaneously with this instant Order addressing the issues raised in T-4626, Sub 1.

Mr. Harvey generally testified in response to questions by the Commission that when Applicant contracts to help residential customers with their intrastate moves, Applicant provides loading and unloading services only unless cleaning services are also purchased. Applicant's employees unload at the customers' final destination point, but they drive themselves to that location in their own vehicles or in the Applicant's vehicles. The customers' HHG are not loaded into Applicant's vehicles nor into the employees' vehicles. The customers supply the vehicles to transport their goods, Applicant loads the goods into vehicles supplied by customers, the customers drive (or arrange for someone other than Applicant to drive) the vehicle and transport their goods to the destination point where they are met by Applicant's employees, who then unload the goods. Applicant and Mr. Harvey specifically avoid transporting goods in intrastate commerce in order not to violate applicable law and regulations pertaining to transportation of HHG. Because Applicant does not provide transportation services, Mr. Harvey often adjusts the usual $125 per hour charge to win the customers' business over other movers. Mr. Harvey testified that Applicant had turned down 33 full service moves in compliance with the legal prohibition against performing full service (including transportation services) moves without first obtaining from the Commission a certificate of exemption. According to Mr. Harvey, these 33 moves could have earned the company $19,000 to $25,000 altogether.[1]

Based on the evidence of record, the Commission concludes that Applicant has presented evidence tending to establish that it has not performed unlawful intrastate household goods moves. Cause was not established to find that Applicant has engaged in any unlawful intrastate move or to impose any related fine or penalty.

REPRESENTING BUSINESS AS AUTHORIZED CARRIER OF HOUSEHOLD GOODS

Because it appeared to the Commission that Applicant was engaged in advertising its business in print and online media, Applicant was ordered to show the Commission why it should not be found to have advertised its services to the public as holding a certificate of exemption or as otherwise being authorized to operate as a carrier of household goods in North Carolina. The Commission concludes based on the testimony of Mr. Harvey and the record as a whole that Applicant violated G.S. 62-280.1 each time it published, caused or allowed to be published or distributed, Applicant's business cards, the "business card" ads in the *Goldsboro News-Argus,* the advertising in *go! Wayne County,* the receipt ads issued at the Goldsboro Harris-Teeter location, and the online advertising on its website and Facebook page.

G.S. 62-280.1(a)(1) expressly provides that "it is unlawful for a person not issued a certificate to operate as a carrier of household goods . . . to . . . orally, in writing, in print, or by sign, including the use of a vehicle placard, phone book, Internet, magazine, newspaper, billboard, or business card, or in any other manner, directly <u>or by implication</u>, represent that the person holds a certificate or is otherwise authorized to operate as a carrier of household goods in [North Carolina]." [Emphasis added.]

[1] Transcript Vol. 3 at 8.

The record shows that Mr. Harvey either purchased or established advertisement on behalf of the Applicant in at least five specific instances that would reasonably mislead the using and consuming public to believe that the Applicant is an authorized moving company or carrier of household goods. First, the record shows that Mr. Harvey paid the *Goldsboro News*-Argus to print its business cards advertising the Applicant's business and services. It is a reasonable inference from the record that Applicant and Mr. Harvey use the business cards to distribute in the promotion of Harvey's Moving Company and its services.

Second, the business cards were replicated as print advertising that ran regularly in the *Goldsboro News-Argus,* a daily local newspaper for Goldsboro and Wayne County, North Carolina, from at least September 2016 through November 2016. The business card and business card ad contained Applicant's name (Harvey's Moving Company), Mr. Harvey's name as the owner, a reference to Applicant's membership in the Wayne County Chamber of Commerce, Applicant's address, phone numbers, an email address, and the Applicant's website. Under Applicant's name was the motto, "Quality Moving with Friendly Customer Service." Neither the card nor the advertisement indicate in any way that Applicant's moving services were limited nor that Applicant did not have authority to perform full service intrastate HHG moves. Likewise, neither the card nor the advertisement stated or claimed that Applicant was a licensed HHG mover and Mr. Harvey testified that he always told inquiring or potential customers that he was not authorized to transport their goods between locations within the state whenever he met with them or discussed services with them. From the record it can be reasonably inferred that copies of the newspaper with Applicant's ad were circulated throughout Goldsboro and Wayne County to the public.

Third, in an October 2016 edition of *go! Wayne County,* which Mr. Harvey described as an insert publication of the *Goldsboro News-Argus,* Applicant's services were advertised. The print ad stated among other things that Applicant provided commercial and residential relocation services. Mr. Harvey testified that he believes the *go! Wayne County* ads were a part of a complimentary package of publishing services he received for purchasing the "business card" ad with the *News-Argus.* Mr. Harvey further testified that he did not specifically provide information for nor was he asked to proof or review the *go! Wayne County* ad. He testified he believes the insert publication obtained information for the ad from the newspaper's knowledge of Applicant's business and from Applicant's business card, Facebook page and website. The *go! Wayne County* advertisement did not indicate in any way that the Applicant's moving services were limited or that Applicant was not authorized to perform full service intrastate HHG moves. The advertisement also did not expressly state or claim that Applicant was a licensed HHG mover.

Despite Mr. Harvey's testimony that he was not aware of the *go! Wayne County* ad or its contents, the record indicates the ad content was derived from information he either provided or was responsible for providing to the *News-Argus* for publication, posting on Applicant's Facebook page and/or posting on the Applicant's website. Therefore, the content of the *go! Wayne County* ad goes to establish or support that the information supplied by Mr. Harvey to the *News-Argus* could reasonably mislead anyone reading it to conclude that Applicant provided residential relocation services to requesting customers without limitation or restriction, *i.e.,* full service residential moves including transportation of HHG. The Commission concludes that Mr. Harvey and Applicant are accountable for the misleading nature of the information printed in *go! Wayne County*. Mr. Harvey acknowledged in response to Commission questions that the advertising alone could be read to include full service residential moves and explained that is one reason he is careful to clarify the precise services Applicant provides after a customer calls him or after he goes to meet the customer at his home. It can be reasonably inferred from the record that copies of *go! Wayne County* advertising Applicant's business and services offered were circulated throughout Goldsboro and Wayne County to the public.

Fourth, the record shows that Mr. Harvey advertised Applicant's moving services on the back of grocery sales receipts distributed by Harris Teeter Grocery Store on Wayne Memorial Drive in Goldsboro, North Carolina from July 26, 2016, through at least November 2016.[1] Applicant's name was clearly printed in the heading of a coupon on back of the receipt. Below the heading of the coupon was the phrase "Quality Moving with Friendly Customer Service." Applicant's address and telephone number were listed in the advertisement with a description of the discounts that were available to customers. For example, the coupon stated that a customer can receive $50 off of a move of $500 or more. The coupon further indicated that a customer can obtain $200 off of "an elite package moving and cleaning." According to Mr. Harvey, the coupon promotion was coordinated by Registered Tape Network, a company out of Durham, North Carolina and was run on a month-to-month basis. As with the business card and newspaper advertising, the receipt-coupon advertisement did not indicate in any way that Applicant's moving services were limited or that Applicant was not authorized to perform full service intrastate moves involving transportation of HHG.

Fifth, the record supports the finding that Mr. Harvey is advertising Applicant's moving services on Applicant's website and Facebook page. Mr. Harvey testified that after performing a moving job he often requests the customer to stand by Applicant's truck in front of their home so he can take photos of them. He posts the photos on the company's webpage at www.harveysmovingcompany.com and on the company's Facebook page in order to attract members of the public to become customers and to contract for Applicant's moving services.[2] Applicant's online advertising highlights residential moves in the description of the company's activities. The webpage states, "Let Harvey's Moving Company move you . . . ." The website also asks and further states, "Moving across town? Moving to the next bigger city? Moving the mother-in-law to an add-on suite? Harvey's Moving Company can help."[3] Again, the Commission concludes Applicant's advertising can mislead members of the public and cause them to believe that Applicant is authorized to provide full service moves of household goods. The language

[1] Commission Sub 1, Exh. 8.

[2] Tr. vol. 3, at 36.

[3] Commission Sub 1, Exhibit 6.

referencing across town and the next bigger city strongly imply Applicant is willing and authorized to perform intrastate moves. It is not lost on the Commission that Mr. Harvey testified that he ultimately advises customers of the limit on the services Applicant may provide as an uncertificated business. However, the misleading nature of Applicant's advertising to date is apparent in Mr. Harvey's own observance that a customer exposed to the advertising would reasonably believe Applicant could provide full service moving until advised otherwise by Mr. Harvey or Applicant.

As discussed above, Harvey's Moving Company filed an application with the Commission for a certificate of exemption to transport household goods by motor vehicle for compensation within North Carolina on April 16, 2016. To date, Applicant has not obtained the required certificate, but has nonetheless, on at least the several occasions noted above, represented through advertising, either directly or by implication, that Applicant is an authorized carrier of HHG in North Carolina. This inappropriate and violative advertising was done after Mr. Harvey received a letter from the Commission's staff advising "that the Applicant is prohibited from engaging in any residential moving activities including advertising until a certificate is issued by the Commission." Accordingly, the Commission concludes that Mr. Harvey advertised the Applicant's moving services in violation of G.S. 62-280.1(a).

The Commission agrees with Mr. Harvey that it is not inappropriate for Applicant to advertise services that do not involve intrastate transportation of HHG for compensation, however, such advertising must be done in a way that does not mislead the public in violation of G.S. 62-280.1(a). There are a number of ways companies that provide manpower services without transportation services can advertise to potential customers the limited moving services they are permitted to provide as a non-certified business.

PENALTIES OR SANCTIONS FOR VIOLATION OF G.S. 62-280.1(a)

Having found and concluded that Mr. Harvey's actions as Applicant's principal, were in violation G.S. 62-280.1(a), the Commission, pursuant to G.S. 62-280.1(c),[1] assesses a civil penalty of five hundred dollars ($500) in United States currency for each of the following types of advertising violations committed on behalf of the Applicant: (1) business cards and business card ads published in print media, (2) other non-business cards ads run in print publications like *go! Wayne County*, (3) sales receipt ads such as the Harris Teeter receipt ads, and (4) online/Internet ads and promotions such as those on Applicant's website and Facebook page. The total assessed penalty of two thousand dollars is payable to the Commission in one sum or in four monthly

[1] Subsection (c) of G.S. 62-280.1 allows the Commission to assess a civil penalty not in excess of five thousand dollars ($5,000) for the violation of subsection (a) of this section. The clear proceeds of any civil penalties collected pursuant to this subsection shall be remitted to the Civil Penalty and Forfeiture Fund in accordance with G.S. 115C-457.2.

payments of five hundred dollars ($500) each beginning fifteen (15) days after the issuance of this Order. If Applicant does not comply with the assessed monetary sanctions, the Commission may take appropriate action pursuant to G.S. 62-312 to recover the assessed penalty. Once the Applicant has paid the penalty in full, the Commission will issue an Order Acknowledging Satisfaction of Penalty.

In assessing the amount of the penalty, the Commission has taken into consideration that while the advertising at issue represented by implication that Applicant was authorized to operate as a carrier of household goods, it did not expressly state that Applicant was licensed or certificated by the Commission.

IT IS, THEREFORE, ORDERED as follows:

1. Applicant shall not operate as a household goods mover performing intrastate residential moves in North Carolina for compensation until it has been issued a certificate of exemption and shall not advertise its services in any way that violates G.S. 62-280.1(a);

2. Applicant shall pay a total civil penalty of two thousand dollars ($2,000) in United States currency to the Commission for violation of G.S. 62-280.1. This monetary fine will be due and payable in one sum or in four equal monthly payments of five hundred dollars ($500), with the first payment due within fifteen (15) days after the issuance of this Order, all remaining payments thereafter due on the same day of each subsequent month as the previous payment(s) until the penalty is fully satisfied;

3. This proceeding will remain open until the Applicant fully completes its financial obligation under the Order. Once the obligation to pay civil penalty is fulfilled, the Commission will issue an Order Acknowledging Satisfaction; and

4. That the Chief Clerk shall serve a copy of this Order on the Public Staff by electronic mail (e-mail) delivery confirmation requested and on Harvey's Moving Company, LLC, and on Bobby D. Harvey and his counsel, by means of United States certified mail, return receipt requested and by e-mail, delivery confirmation requested.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of August, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

DOCKET NO. W-218, SUB 461

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Aqua North Carolina, Inc. for Approval of a Long-Term Debt Agreement Pursuant to G.S. 62-153, G.S. 62-161, and Commission Rule R1-16 and Refinancing of Debt Maturities	)))))	ORDER APPROVING ISSUANCE OF NOTE PAYABLE

BY THE COMMISSION: On June 29, 2017, Aqua North Carolina, Inc. (Aqua NC or the Company) filed a verified Application pursuant to G.S. 62-153, G.S. 62-161, and Commission Rule R1-16 for authorization to issue additional debt in accordance with an unsecured note to Aqua America, Inc. (Aqua America or the Parent), similar to the approvals issued by the Commission on November 13, 2015, in Docket No. W-218, Sub 22; on May 8, 2012, in Docket No. W-218, Sub 337; on June 18, 2009, in Docket No. W-218, Sub 297; and on December 21, 2010, in Docket No. W-218, Sub 320. In addition, the Company requests approval to refinance certain debt that will mature on December 31, 2017.

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. Aqua NC is a public utility operating in North Carolina providing water and wastewater utility service to the public for compensation. The Company provides utility service to approximately 79,400 water customers and approximately 17,800 wastewater customers in North Carolina under authority granted by this Commission.

2. The Company is a direct, wholly-owned subsidiary of Aqua America, a Pennsylvania corporation.

3. On November 13, 2015, the Commission approved Aqua NC's request in Docket No. W-218, Sub 422 to execute a note to Aqua America for long-term debt in the principal amount up to $70,968,398.

4. Aqua NC now proposes to add additional debt in the amount not to exceed $15,000,000 for an aggregate total debt balance of $85,968,398.

5. Pursuant to G.S. 62-153, G.S. 62-161, and Commission Rule R1-16, the Company requests approval to replace the earlier note that was the subject of Commission approval in Docket No. W-218, Sub 422 with the issuance of additional debt in the form of an unsecured note, as shown in Exhibit A to the verified Application, and asserts that the proposed issuance: (i) is for a lawful object within the corporate purposes of Aqua NC as a public utility; (ii) is compatible with the public interest; (iii) is necessary, appropriate for, and consistent with the proper performance

by Aqua NC of its service to the public; (iv) will not impair Aqua NC's ability to perform that service; and (v) is reasonably necessary and appropriate for the purposes for which it is issued.

6. In the event of Commission approval, Aqua America will cancel the promissory note in the amount of $70,968,398 which was approved in Docket No. W-218, Sub 422.

7. A provision in the Commission-approved note allows prepayment of the principal plus any outstanding interest. Thus, the debt can be paid off at any time during the term of the note without penalty. In addition, the interest rates in the note reflect the coupon rates with no adjustment for premiums or discounts. The debt was issued at par. A portion of the debt issuance costs related to Aqua NC debt will be amortized over the life of the loan by the Company. An estimate of the expenses associated with the transactions is attached to the Verified Application as Exhibit B..

8. The Company asserts that there are significant advantages to this approach. Aqua America is well-known in the financial markets and the costs of completing this transaction at the corporate level are less than they would be at the state level.

9. This debt issued by Aqua NC's parent company, Aqua America, is for the benefit of Aqua NC ratepayers and thus is compatible with the public interest. Aqua America is able to borrow debt at lower rates that its North Carolina subsidiary could if Aqua NC were to attempt to issue debt on its own as a "stand-alone" company. The Company submits that Aqua NC ratepayers directly benefit from the issuance of this note due to the lower interest rates afforded to the Parent and the result is a reduction in the overall weighted cost of debt in North Carolina.

10. The purpose of borrowing capital for North Carolina is to fund rate base additions, to maintain existing facilities, and to fund the working capital and investment capital requirements of Aqua NC. A listing of the projects is attached to the verified Application as Exhibit C.

11. In addition to the application to add debt to the Commission-approved note, the Company respectfully requests approval to refinance $2,196,290 of debt that will mature on December 31, 2017. The Company states that the replacement debt results in a one hundred ninety-seven (1.97%) basis point reduction compared to the maturing debt as shown in Exhibit G.

12. Certain terms of the note and provisions were summarized by Aqua NC as follows:

AGGREGATE PRINCIPAL AMOUNT:

The principal sum of up to eighty-five million nine hundred sixty-eight thousand three hundred ninety-eight dollars and no cents ($85,968,398) in more than one separate series.

AQUA NORTH CAROLINA, INC.

LONG-TERM DEBT SCHEDULE

Series	Interest Rate	Issue Date	Maturity Date	Amount
Senior Unsecured Notes	4.87%	07/31/03	07/31/18	1,948,371
Senior Unsecured Notes	4.87%	07/31/03	07/31/20	4,860,925
Senior Unsecured Notes	4.87%	07/31/03	07/31/23	4,041,604
Senior Unsecured Notes	5.20%	02/03/05	02/03/20	2,800,586
Senior Unsecured Notes	5.63%	02/28/07	02/28/22	3,685,069
Senior Unsecured Notes	5.85%	02/28/07	02/28/37	3,299,664
Senior Unsecured Notes	5.40%	05/20/08	05/20/21	765,000
Senior Unsecured Notes	5.54%	12/27/06	12/31/18	2,210,263
Senior Unsecured Notes	4.72%	12/17/09	12/17/19	22,639,371
Senior Unsecured Notes	4.62%	06/24/10	06/24/21	1,100,000
Senior Unsecured Notes	4.83%	06/24/10	06/24/24	1,100,000
Senior Unsecured Notes	5.22%	06/24/10	06/24/28	11,450,836
Senior Unsecured Notes	3.57%	06/14/12	06/14/27	14,435,409
Senior Unsecured Notes	3.59%	05/20/15	05/20/30	11,631,300
Total				85,968,398

13. The following Exhibits were appended to the verified Application and made a part thereof:

Exhibit A: Promissory Note between Aqua America and Aqua NC.

Exhibit B: Estimate of the expenses to be incurred in connection with the pledging of assets, the issuance and sale of securities, or the assumption of liabilities.

Exhibit C: Purpose or purposes to which the proceeds obtained are to be used.

Exhibit D: Aqua NC's balance sheet and income statements as of March 31, 2017.

Exhibit E: Please see the following link for Aqua America SEC filings: http://ir.aquaamerica.com/sec.cfm.

Exhibit F: Aqua NC's Cash Flow Statement for the Year Ended March 31, 2017.

Exhibit G: Debt Refinancing.

Exhibit H: Proposed Order Approving Verified Application for Approval of Long-Term Debt Agreement and Refinancing of Debt Maturities.

WHEREUPON, the Commission now reaches the following:

CONCLUSIONS

Based upon the foregoing Findings of Fact and the entire record in this proceeding, the Commission is of the opinion and so finds and concludes that the long-term debt transaction proposed herein:

(i) Is for a lawful object within the corporate purposes of Aqua NC as a public utility;
(ii) Is compatible with the public interest;
(iii) Is necessary, appropriate for, and consistent with the proper performance by the Company of its service to the public as a utility;
(iv) Will not impair Aqua NC's ability to perform its public utility service; and
(v) Is reasonably necessary and appropriate for the purposes for which issued.

IT IS, THEREFORE, ORDERED that the verified Application filed by Aqua North Carolina, Inc. in this docket on June 29, 2017, is hereby approved and the Company is hereby authorized, empowered and permitted to (1) make, execute and deliver to Aqua America a note for long-term debt in an amount not to exceed $85,968,398 principal amount; (2) refinance $2,196,290 of debt that will mature on December 31, 2017; and (3) take such actions as are reasonable and necessary to effectuate all transactions described in the Company's verified Application and Exhibits appended thereto.

IT IS FURTHER ORDERED that the Commission's approval in this docket does not restrict the Commission's regulatory authority to review and adjust, if the Commission deems it appropriate to do so, Aqua NC's cost of capital and/or expense levels for ratemaking purposes in the Company's next general rate case.

ISSUED BY ORDER OF THE COMMISSION
This 18th day of July, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

Commissioner Daniel G. Clodfelter did not participate in this decision.

DOCKET NO. W-1314, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Pluris Webb Creek, LLC, for Temporary Operating Authority to Serve The Pines Development in Onslow County, North Carolina, and for the Eventual Approval of a Certificate of Public Convenience and Necessity	)	ORDER APPROVING TEMPORARY OPERATING AUTHORITY, APPROVING INTERIM RATES, REQUIRING UNDERTAKING, AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On December 22, 2016, Pluris Webb Creek, LLC (Pluris), filed an application for a certificate of public convenience and necessity (CPCN), and pursuant to G.S. 62-116 for temporary operating authority, to provide wastewater utility service for 34 existing single-family residences in areas known as Eastport I and Timber Ridge, and for 44 to be constructed new single-family residences at Eastport Section III, Phase 1, which are part of The Pines Development in Onslow County, and for approval of rates (Pluris Application). G.S. 62-116(a) provides that the Commission may grant an applicant temporary operating authority upon a finding that no other adequate service exists. Pluris proposes to serve this area utilizing the nearby Webb Creek wastewater system owned by Webb Creek Water and Sewage, Inc. (WCWS), and operated by Pluris as an emergency operator (EO) pursuant to the Commission's Order issued on August 8, 2016, in Docket No. W-864, Sub 11 (the EO Order).

The Public Staff presented this matter at the Commission's Staff Conference on January 23, 2017.

Based upon the Public Staff's Petition and the Commission's records, the Commission makes the following

FINDINGS OF FACT

1. Pluris is a public utility and a wholly owned subsidiary of Pluris Holdings, LLC. Other wholly owned subsidiaries of Pluris Holdings include (1) Pluris, LLC, which is a public utility operating a wastewater utility system serving North Topsail and nearby mainland areas near Sneads Ferry in Onslow County, and (2) Pluris Hampstead, LLC, which is a public utility operating a regional wastewater system near Hampstead in Pender County.

2. As of December 1, 2016, Pluris as EO has spent $187,143 in efforts to renovate the Webb Creek system to address compliance issues, and recover treatment capacity that had been lost. Pluris states it has brought the Webb Creek wastewater system into substantial compliance with environmental and operational requirements.

3. The Pines Development is located near the Webb Creek wastewater system. The Pines Development consists of an existing mobile home park, 34 existing single-family residences known as Eastport I and Timber Ridge, and other lots to be developed as single family residences.

The developer of The Pines Development, National MHP Holdings LLC (National MHP), also plans to develop the area that now consists as the mobile home park as lots for single family residences, once the mobile home park is phased out. The next phase of the development will consist of 44 new homes in Eastport Section III, Phase 1. The Onslow Water and Sewer Authority (ONWASA) provides the water utility service to both The Pines Development and Webb Creek.

4. The existing mobile home park in The Pines Development is served by Pines Utilities, Inc. (PUI). The Public Staff stated the owners of National MHP and PUI are the same individuals. PUI's franchised service area is limited to the mobile home park in The Pines Development. On October 1, 2015, PUI previously filed a Notification of Intention to Begin Operations in Area Contiguous (Notice) in Docket No. W-822, Sub 2, for the 34 parcels in Eastport I and Timber Ridge, which is part of the service area in this Pluris Application.

5. PUI's wastewater treatment plant is very near the end of its useful life. The effluent disposal for PUI wastewater system is through a drainfield with underground low pressure pipe. PUI has stated that it is anxious for Pluris to become the wastewater utility service provider for the entirety of The Pines Development. As a result of PUI's discussions with Pluris, PUI requested its Notice filed October 1, 2015, be held in abeyance.

6. Branch Banking & Trust Company (BB&T) made loans to WCWS which were secured by the Webb Creek wastewater utility system assets owned by and used by WCWS. WCWS defaulted on those loans, and as a result, BB&T now holds both mortgage and judgment liens against WCWS's wastewater system assets. Pluris has advised the Public Staff that Pluris is in advanced negotiations with BB&T to acquire the franchise and wastewater utility system assets of WCWS.

7. National MHP has entered into an Agreement for Sanitary Sewer Service with Pluris dated October 26, 2016 (Developer Agreement). The Developer Agreement provides for Pluris to pay the cost to construct the pump station and force main interconnect to the Webb Creek system. National MHP will pay connection fees of $1,800 per single family residential equivalent, and construct at its cost the wastewater collection system within The Pines Development.

8. Pluris, as EO for WCWS, filed an Application for a CPCN in Docket No. W-864, Sub 12, to expand WCWS's service area to serve the existing 34 detached single-family residences in Eastport I and Timber Ridge. WCWS is owned and managed by J. Hal Kinlaw, Jr. (Mr. Kinlaw). On November 10, 2016, Mr. Kinlaw was sentenced to 17 years in federal prison and is currently incarcerated at the Federal Correctional Institute in Ashland, Kentucky.

9. The Public Staff advised Pluris that it cannot recommend to the Commission that WCWS's service area be expanded as requested in Docket No. W-864, Sub 12, as WCWS lacks the necessary managerial, financial, and operational capacity to provide service. The Public Staff suggested that Pluris request authority to serve the 34 existing residences in Eastport I and Timber Ridge, and the 44 new homes, which will be built in Eastport Section III, Phase I, of The Pines Development as provided in the Pluris Application.

10. Pluris has made significant capital expenditures for the Webb Creek wastewater plant in an effort to bring it into compliance with environmental requirements. Pluris has also committed to expand that plant in an expedient and environmentally sound manner, after Pluris acquires WCWS's assets. If Pluris is able to secure ownership of all necessary assets, Pluris will convert the existing Webb Creek wastewater treatment plant into a membrane bioreactor (MBR) wastewater treatment plant, which produces very high quality effluent.

11. The Public Staff believes the remedial work that Pluris has undertaken at the Webb Creek plant, along with future plans for a MBR wastewater treatment plant, present an opportunity to economically benefit both the existing WCWS ratepayers at Webb Creek and future ratepayers in The Pines Development. If Pluris can use the existing Webb Creek plant to serve ratepayers at the new single-family residences in The Pines Development, those ratepayers can avoid having to bear the cost of a new wastewater treatment plant for PUI. The Public Staff also believes that such a result would benefit the existing ratepayers at Webb Creek by allowing the cost of operating the Webb Creek system and the future MBR plant, to be spread over a larger number of ratepayers, comprised of both Webb Creek and The Pines Development ratepayers. Further, the Public Staff believes that no other adequate service is available in the area as PUI does not desire to serve Eastport I, Timber Ridge, or Eastport Section III, Phase 1, the existing PUI wastewater treatment plant is near the end of its useful life with continued operations becoming substantially less dependable, and a replacement wastewater treatment plant at The Pines Development would result in rate shock.

12. Pluris has applied for a monthly flat rate of $37.69 per single family equivalent (SFE), which is the same rate the Commission approved for Pluris as EO at Webb Creek.

13. The Public Staff recommended that the Commission approve Pluris' request for temporary operating authority to provide wastewater service utilizing the Webb Creek wastewater system to the portion of The Pines Development consisting of the 34 single-family residences in Eastport I and Timber Ridge, and the 44 new homes in Eastport Section III, Phase 1, of the planned further development. The Public Staff believes the temporary operating authority will enable Pluris to take constructive steps to achieving a well-managed, well-operated, and financially viable regional wastewater public utility system, which will ensure the customers of continuous cost effective adequate service. The Public Staff further recommended that the Commission take no action on the application for a CPCN until Pluris has acquired ownership of the necessary Webb Creek wastewater utility assets.

14. The Public Staff recommended that the Commission issue Pluris temporary operating authority and approve the following interim rates:

Monthly Flat Rate (Residential)	$37.69 per SFE

15. The Public Staff recommended a bond in the amount of $10,000 for this service area during the Commission's Staff conference. On January 25, 2017, Pluris filed a corporate surety bond in the amount of $10,000, and has met the filing requirements for a corporate surety bond.

CONCLUSIONS

Based upon the Application, the foregoing findings of fact, and the recommendations of the Public Staff, the Commission concludes that it is in the public interest for Pluris to be issued temporary operating authority for Eastport I, Timber Ridge, and Eastport Section III, Phase 1, pending the Commission's final decision on the Pluris application for a CPCN; that the interim rates recommended by the Public Staff should be approved subject to undertaking; that a public hearing should be scheduled by further order of the Commission, subject to cancellation if no significant protests are filed with the Commission; and that customer notice should be provided .

IT IS THEREFORE, ORDERED as follows:

1. That the commercial surety bond filed in this proceeding, as surety for the bond amount of $10,000 required by the Commission, is hereby accepted and approved.

2. That Pluris Webb Creek, LLC, is issued temporary operating authority to provide wastewater utility service in Eastport I, Timber Ridge, and Eastport III, Phase 1, in Onslow County North Carolina, effective on the date of this Order.

3. That Appendix A, attached hereto, constitutes the Temporary Operating Authority.

4. That the Schedule of Interim Rates, attached hereto as Appendix B, is approved and deemed to be filed with the Commission pursuant to G.S. 62-138. Said Schedule of Interim Rates is authorized to become effective for service rendered on and after the date of this Order and are subject to an undertaking to refund by Pluris, with 10% interest per annum, any portion of the interim rates which are not ultimately approved by the Commission.

5. That Pluris shall execute and file the Undertaking, attached hereto as Appendix C, no later than 10 days after the date of this Order.

6. That an order scheduling public hearing and requiring customer notice shall be issued by the Commission at a later date. This hearing may be canceled if no significant protests are received subsequent to public notice.

7. That a copy of this Order, including Appendices A and B, attached thereto, shall be mailed with sufficient postage or hand delivered to all the Eastport I and Timber Ridge wastewater utility system customers, no later than 10 days after the date of this Order and that Pluris submit to the Commission the attached Certificate of Service, properly signed and notarized, not later than 15 days after the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of February, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

WATER AND SEWER – CERTIFICATE

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX A

DOCKET NO. W-1314, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

PLURIS WEBB CREEK, LLC

is granted this

TEMPORARY OPERATING AUTHORITY

to provide sewer utility service

in

EASTPORT I AND TIMBER RIDGE, AND EASTPORT SECTION III, PHASE I

Onslow County, North Carolina

subject to any orders, rules, regulations,
and conditions now or hereafter lawfully made
by the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.

This the 1st day of February, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

WATER AND SEWER – CERTIFICATE

APPENDIX B

SCHEDULE OF INTERIM RATES

for

PLURIS WEBB CREEK, LLC

for providing wastewater utility service in

EASTPORT I, TIMBER RIDGE, EASTPORT SECTION III, PHASE 1

Onslow County, North Carolina

Monthly Flat Rate (Residential):	$37.69 per SFE[1/]
Connection Fee:	
Residential	$1,800 per SFE[1/]
Reconnection Fees:	
If sewer is cut off by utility for good cause:	$141.00
Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Returned Check Fee:	$20.00
Finance Charges for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date

[1/] Single family equivalent (SFE)

____ Issued in accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1314, Sub 0, on this the 1st day of February, 2017.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX C

DOCKET NO. W-1314, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Pluris Webb Creek, LLC, for) Temporary Operating Authority to Serve The) Pines Development in Onslow County, North) Carolina, and for the Eventual Approval of a) Certificate of Public Convenience and Necessity)	UNDERTAKING

NOW COMES Pluris Webb Creek, LLC (Applicant), and files this Undertaking as follows:

UNDERTAKING

The Applicant, by and through its undersigned owner/executive officer, makes its written undertaking to the North Carolina Utilities Commission that it will refund to its customers any amount of the approved interim rate, plus 10% interest per annum, that may be finally determined by the Commission to be excessive and is required by Final Order of the Commission.

This the ______ day of ________________, 2017.

By: ______________________________

____
(Owner/President)

WATER AND SEWER – CERTIFICATE

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers a copy of the Order issued by the North Carolina Utilities Commission in Docket No. W-1314, Sub 0, and such Order was mailed or hand delivered by the date specified in the Order.

This the ___ day of ________________, 2017.

By: ________________________________

Signature

____

Name of Utility Company

The above named Applicant, _______________________________________, personally appeared before me this day and, being first duly sworn, says that the required copy of the Commission Order was mailed or hand delivered to all affected customers, as required by the Commission Order dated _________________________ in Docket No. W-1314, Sub 0.

Witness my hand and notarial seal, this the ___ day of _________________, 2017.

____

Notary Public

____

Printed Name

My Commission Expires: ________________________________

Date

DOCKET NO. W-1309, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition for Declaratory Ruling by The Villages of Bishops Ridge Association	))	ORDER ISSUING DECLARATORY JUDGMENT

BY THE COMMISSION: On August 17, 2015, The Villages of Bishops Ridge Association[1] (Bishops Ridge HOA or Petitioner) filed a Petition requesting a declaratory ruling that by providing bulk water to the adjacent Village of Bishops Ridge IV Association[2] (BRIV HOA), "Bishops Ridge is not a public utility within the meaning of G.S. 62-3(23), does not own or operate in this State equipment or facilities for '[d]iverting, developing, pumping, impounding, distributing or furnishing water to or for the public for compensation, and is not a utility as defined in Commission Rule R7." Petition, p. 1.

According to the Petition, The Villages of Bishops Ridge Subdivision (Bishops Ridge Subdivision) is a residential community located in Charlotte, North Carolina with 153 townhome and single family homes. Bishops Ridge HOA owns and operates a water distribution system to serve its residential members within the Bishops Ridge Subdivision. Bishops Ridge HOA buys bulk water from Charlotte Water, formerly known as the Charlotte-Mecklenburg Utility Department (CMUD), and is served through nine meters that were installed as the various sections of the Bishops Ridge Subdivision were developed.

Phase IV of the Villages of Bishops Ridge Subdivision (Phase IV Subdivision) is a residential community located adjacent to the Bishops Ridge Subdivision. The initial development plan for Phase IV Subdivision included direct connection to the CMUD water system, but that never occurred. Instead, Phase IV Subdivision's distribution system was tied in with Bishops Ridge HOA's infrastructure and water is currently provided to BRIV HOA and fifty-nine (59) homes in Phase IV Subdivision by Charlotte Water through Bishops Ridge HOA's distribution system.

There are no master meters between Bishops Ridge HOA's and BRIV HOA's distribution systems. There are no water meters at any of the individual residences in either the Bishops Ridge Subdivision or the Phase IV Subdivision. Each month Charlotte Water reads the various meters within Bishops Ridge HOA and issues a bill to Bishops Ridge HOA. Bishops Ridge HOA makes full payment to Charlotte Water, determines the pro rata share owed by BRIV HOA for the water

[1] Bishops Ridge HOA is a non-profit corporation formed pursuant to Chapter 55A of the North Carolina General Statutes. Bishops Ridge HOA serves as the homeowners association for the residents of Bishops Ridge Subdivision. The residents and leaseholders of residents of Bishops Ridge Subdivision are member-owners of Bishops Ridge HOA.

[2] BRIV HOA is a non-profit corporation formed pursuant to Chapter 55A of the North Carolina General Statutes. BRIV HOA serves as the homeowners association for the residents of the Phase IV Subdivision. The residents and leaseholders of residents of the Phase IV Subdivision are resident-members of BRIV HOA. Neither BRIV HOA nor its resident-members are members of Bishops Ridge HOA. Thus, BRIV HOA and/or the resident-members of BRIV HOA are a non-member customer and/or non-member customers of Bishops Ridge HOA.

used by BRIV HOA's resident-members and delivers a bill to BRIV HOA for the pro rata share of the water used by BRIV HOA's resident-members.

Bishops Ridge HOA's member-owners pay for water as a part of their homeowners' association assessment. BRIV HOA's member-owners also pay for the water delivered from Bishops Ridge HOA as a part of their HOA assessment.

This pass-through arrangement has been ongoing since 1999. According to Bishops Ridge HOA, BRIV HOA is Bishops Ridge HOA's only customer and Bishops Ridge HOA has no intention of serving any more customers.

On May 23, 2016, the Public Staff presented this matter at the Commission's Regular Staff Conference. The Public Staff stated that it too agrees that Bishops Ridge HOA is not a public utility as defined in G.S. 62-3(23)a.2 or a utility as set forth in Commission Rule R7-2(a) based upon the decision in State ex rel. Utilities Commission v. Simpson, 295 N.C. 519, 246 S.E.2d 753 (1978) and prior Commission rulings. The Public Staff thereafter joined in Bishops Ridge HOA's request that the Commission issue a declaratory ruling that Bishops Ridge HOA's sale of bulk water does not make Bishops Ridge HOA a public utility as defined in G.S. 62-3(23)a.2 and Commission Rule R7-2(a).

DISCUSSION

In the case presently before the Commission, Bishops Ridge HOA petitioned the Commission to issue a declaratory ruling that it is not a public utility within the meaning of G.S. 62-3(23)a.2 and Commission Rule R7-2(a) when it furnishes water to the BRIV HOA for compensation. According to Bishops Ridge HOA, "[r]elevant case law and the facts dictate a finding that Bishops Ridge [HOA] is not a public utility [because] [i]t does not act [like] a public utility, there is no compelling reason that it needs to be a regulated public utility, and the Commission's determination that it is not a public utility will cause no harm to the public at large or the users of Bishops Ridge [HOA]'s water pipes." Petition, p. 6. Bishops Ridge HOA cited the decision in Simpson and various decisions by the Commission as support for its contention that it is not a public utility as defined in G.S. 62-3(23)a.2. and Commission Rule R7.2(a).

The Commission has carefully reviewed the Petition, the arguments set forth above, the Staff Conference filing by the Public Staff, and the Public Staff's oral presentation to determine if Bishops Ridge HOA's sale of water to BRIV HOA would cause Bishops Ridge HOA to be deemed a public utility. Based upon this review and the Public Utilities Act, the Commission finds and so concludes that Bishops Ridge HOA is a public utility as the term is defined in G.S. 62-3(23)a.2 when it uses its facilities to furnish water utility service to 59 non-member customers residing in the Phase IV Subdivision for compensation.[1]

[1] According to the facts cited in the Petition, Bishops Ridge HOA provides water to 59 residences in the Phase IV Subdivision, although BRIV HOA stands between Bishops Ridge HOA and the residential customers for purposes of facilitating delivery of payment to Bishops Ridge HOA.

G.S. 62-3(23)a.2 defines a public water utility as a person owning or operating equipment or facilities for:

> Diverting, developing, pumping, impounding, distributing or furnishing water to or for the public for compensation,[or operating a public sewerage system for compensation]; provided, however, that the term "public utility" shall not include any person or company whose sole operation consists of selling water to less than 15 residential customers; except that any person or company which constructs a water system in a subdivision with plans for 15 or more lots and which holds itself out by contracts or other means at the time of said construction to serve an area containing more than 15 residential building lots shall be a public utility at the time of such planning or holding out to serve such 15 or more building lots, without regard to the number of actual customers connected.

When G.S. 62-3(23)a.2 is construed and interpreted as a whole and every part thereof given effect, the definition of a water public utility is fairly straight forward. Duke Power Company v. Clayton, 274 N.C. 505, 164 S.E. 2d 289 (1968). Pursuant to the statute, a person is a water public utility who owns or operates equipment for furnishing water to the public for compensation. However, the statute continues on to specifically address residential water service, as opposed to any other type of water customer. The statute provides that if a person or company provides water service to less than 15 residential customers, such person or company is not a public utility and is not subject to regulation by the Commission. It thus follows directly from the context of the statute that a person or company providing water service to 15 or more residential customers for compensation is a public utility subject to the Commission's regulatory authority.[1] The Commission notes that in enacting the statute the legislature was clear in its intent that any group of 15 or more residential water customers being served by a provider would have the protections afforded by the Public Utilities Act, *i.e.*, Chapter 62 of the North Carolina General Statutes ("Chapter 62").

In providing service to the residents of Phase IV Subdivision, Bishops Ridge HOA is serving more than 15 residential customers for compensation. Thus, Bishops Ridge HOA is a public utility when it provides service to BRIV HOA and its members who reside in Phase IV Subdivision. Neither of two possibly applicable exemptions found in G.S. 62-3(23)d apply to Bishops Ridge HOA based on the facts of record. First, if the Phase IV Subdivision residents were members of Bishops Ridge HOA, then Bishops Ridge HOA could possibly be exempt from regulation under the clause in G.S. 62-3(23)d, which states "the term 'public utility' . . . shall not include . . .any person . . . who furnishes such service or commodity only to himself . . . when such service or commodity is not resold to or used by others." It could be argued for the purpose of

[1] Under the doctrine of *expressio unius est exclusio alterius*, the mention of this specific exception for serving less than 15 customers implies the exclusion of others. Good Hope Hospital, Inc. v. N.C. Department Health and Human Services, 175 N.C. App. 309, 623 S.E.2d 315 (2006) aff'd 360 N.C. 641, 636 S.E. 2d 564(2006); Campbell v. Church, 298 N.C. 476, 484, 259 S.E.2d 558, 564 (1979). Thus, the legislature's specific reference to this numerical limitation by which one is exempt from public utility status demonstrates its intent that any water utility provider selling water to 15 or more residential customers shall be a public utility. That the legislature clearly intended this line of demarcation is further evinced by the fact that the General Assembly expressly stated that that any person that planned or constructed a water utility system intended to serve 15 or more residential building lots "shall be a public utility [] without regard to the number of actual customers connected." Emphasis added.

determining the number of customers served, that member-owners of a water system such as Bishop Ridge HOA's are not customers of the system, but are owners collectively paying to own and maintain their system for their own water service. However, the 59 customers in the Phase IV Subdivision are not member-owners of Bishops Ridge HOA and its water system. Instead, they are merely residential customers of Bishops Ridge HOA whose payments to Bishops Ridge HOA routed through BRIV HOA do not provide them any ownership in the Bishops Ridge HOA water system, but provides them only with water utility service allowing them to receive and use the commodity of water. Therefore, referring back to the definition of a water public utility in G.S. 62-3(23)a.2, Bishops Ridge HOA is serving more than 15 non-owner residential customers for compensation when it provides water service to the residents of Phase IV Subdivision and is paid by the customers, either directly or indirectly through their agent, BRIV HOA, to provide that service.

Second, ordinarily Bishops Ridge HOA could be considered for exemption under G.S. 62-3(23)d, which grants regulatory exemption to "a homeowners' association that provides water or sewer service "only to members or leaseholds of members." However, that exemption is not available to Bishops Ridge HOA when it serves the Phase IV Subdivision residents because they are not members or leaseholds of members of Bishops Ridge HOA. This means that Bishops' Ridge HOA is providing service to other than its members or leaseholds of members and is not exempt from public utility status to the extent its system serves more than 15 Phase IV Subdivision residential customers.

In their pleadings, Bishops Ridge HOA and the Public Staff both contend that Bishops Ridge HOA is providing service to a single customer, i.e., BRIV HOA. The suggestion is that Bishops Ridge has only one non-member owner customer and is exempt from regulation as a provider to fewer than 15 residential customers. The Commission rejects this contention because to do otherwise would exalt form over substance and, as discussed below, would leave the Phase IV Subdivision residential customers without protection from their monopoly provider of utility service affected with the public interest and necessary to life. The Commission is not convinced that Bishops Ridge HOA is making a bulk water sale to BRIV HOA based on the information before it. At best, BRIV HOA is an agent/representative for its 59 member-residents of Phase IV Subdivision and is subject to the control of its member/residents. Thus, in substance, this sale is more akin to a direct retail sale to 59 residential customers than a bulk water sale to another public utility who thereafter provides service to retail customers.

The Commission's conclusion that BRIV HOA merely stands between Bishops Ridge HOA and the resident members of BRIV HOA as a collection agent for ease of invoicing and payment is reasonable in light of the Supplemental Declaration of Covenants, Conditions and Restrictions for the Villages of Bishops Ridge IV (Supplemental Covenants), which state that the "[o]wners of the subdivided lots (as defined in the Declaration) within the Submitted Property shall pay to the Bishops Ridge Association, or its agent, based on an invoice ("Invoice") for the charge of the water service[.]" See Exhibit 2. This language and other language contained in the

Supplemental Covenants contradicts the contention that Bishops Ridge HOA is selling water to a single customer and that the sale of such water is a bulk water sale. [1] In fact, from the quoted provision it is quite clear the drafters of the Supplemental Covenants contemplated that each residence owner in Phase IV Subdivision would be a water customer of Bishops Ridge HOA, making individual payment directly to Bishops Ridge HOA for water service rendered. While agreeing with Bishops Ridge HOA's statement and implicit argument in its Petition that "[it] was not a party to the Supplemental [Covenants]" and thus not bound by the customer/provider relationship described in the Supplemental Covenants, the Commission nevertheless finds the Supplemental Covenants informative and relevant on the question as to whether Bishops Ridge HOA is actually serving one or fifty-nine customers in providing water to the residents of Phase IV Subdivision through the pass-through arrangement described hereinabove.

Because the residents of Phase IV Subdivision *are* bound by the Supplemental Covenants which require each of them to pay Bishops Ridge HOA, it seems more likely than not that BRIV HOA is serving as the agent for its members in transmitting payments collected from its member owners to Bishops Ridge HOA. The contention that Bishops Ridge HOA is making a bulk water sale to a single customer does not require the Commission to look beyond the facts that Phase IV Subdivision residents are being served by Bishops Ridge HOA; that they are paying Bishops Ridge HOA indirectly through their agent, BRIV HOA; that BRIV HOA is transmitting to Bishops Ridge HOA the money payments made by Phase IV Subdivision residents with the intent that such payments are to compensate Bishops Ridge HOA for providing them with water service through

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[1] In pertinent part, the Supplemental Covenants state:

1. Water service shall be supplied to the Submitted Property by means of and as a part and extension of its existing private water supply system for the [] Bishops Ridge Properties [].

2. Owners of subdivided Lots [] within the Submitted property shall commence paying water bills submitted by the Bishops Ridge Association upon the issuance of a building permit by Mecklenburg County, North Carolinas. Notice shall be given to Bishops Ridge Association when lots are permitted by Mecklenburg County, North Carolina. Developer will notify the Bishops Ridge Association when lots are conveyed to Torrey or any other entity. Torrey shall cause the closing agent involved at the time of the sale of any Lot to a new Owner who has purchased the Lot for residential purposes to pay for the initial months water bill (and any partial month if the closing takes other than the first of the month) as provided herein, together with a notice of transfer to the management company for Bishops Ridge Association which will allow *Bishops Ridge Association to properly invoice the new Owner. The new Owner of the Lot shall pay water bills as provided in paragraph 4 below.*[Emphasis added.]

3. Charges for water service shall be calculated by the Bishops Ridge Association by dividing pro rata the actual or estimated water bill (as determined by a line item in the Bishops Ridge Association annual budget of common expenses) by the total number of lots within the Bishops Ridge Properties (currently 151 lots) and the number of lots within the Submitted Property which have been issued building permits (up to a total of 59 homes at build-out).

4. Owners of Lots within the Submitted Property shall pay to the Bishops Ridge Association, or its agent, based on an invoice ("Invoice") for the charge of the water service, the actual cost of billing and collection, and a pro rata share of the reserve account maintained by the Bishops Ridge Association (as set forth in a line item in the Bishops Ridge Association annual budget of common expenses) for the repair and maintenance of the main line of the water system serving Bishops Ridge IV.

its meters with Charlotte Water and are not to be kept by BRIV HOA as its own revenue; and that BRIV IV HOA does not do anything to provide or furnish water to the Phase IV Subdivision residents and has no meters through which it is capable of providing water to the Phase IV Subdivision residents or of invoicing the residents for their water usage. Calling the pass through arrangement a bulk water sale, even if the two homeowners' associations agreed to call it such, does not convert retail sales to 59 customers into a bulk water sale. The Commission sees this arrangement/agreement between the associations for what it is: a way for Bishops Ridge HOA to provide water to the residents of Phase IV Subdivision and to be paid for providing such water service. Moreover, being bound by the Supplemental Covenants, BRIV HOA and its member owners, the Phase IV Subdivision residents, were not free to change the relationship described in the Covenants whereby they receive water service from Bishops Ridge HOA and make payment to Bishops Ridge HOA for that service. It is clear from the Supplemental Covenants that Phase IV residents receive water utility service from Bishops Ridge HOA and not from BRIV HOA. Bishops Ridge HOA, having knowledge of the relationship described in the Supplemental Covenants that was binding on BRIV HOA, was aware or should have been aware that any agreement with BRIV HOA and its members purporting to change the provider/customer relationship established in the Supplemental Covenants would be ultra vires and void, and also would not cause BRIV HOA to become the utility service provider for its member-residents of Phase IV Subdivision.

However, even if the Commission found that Bishops Ridge HOA is making a bulk water sale to BRIV HOA, that finding would not excuse Bishops Ridge HOA from public utility status on the facts as presented by the Petitioner. While the Petitioner and the Public Staff argue that Bishops Ridge HOA should not be a public utility under the reasoning of Simpson and that such a holding by the Commission would cause no harm to the public or the Phase IV Subdivision customers, the Commission is instead persuaded that Simpson supports the Commission's conclusion that Bishops Ridge HOA is a public utility when providing water service for compensation to the Phase IV Subdivision residents and members of BRIV HOA. In Simpson, the petitioner argued that his radio communication service was not a public utility because he offered service to a narrow class or small market of no more than the 60 potential customers who were members of the county medical society and his actual number of customer was even smaller at 9. According to the petitioner, the number of persons to and by whom his service was offered and taken was too small to meet the requirement that a public utility by definition must offer service to the public. In rejecting the petitioner's argument, the Simpson court warned that adopting a definition of public that allows an offeror to approach small market slices or definable classes without falling under the statute as a regulated public utility runs the risk of shifting a regulated industry to one that becomes largely unregulated, contrary to the legislature's designation of regulated utility industries. Customers the legislature intended to protect would find themselves outside the protections afforded by Chapter 62.

Simpson indeed agreed that an inflexible definition of "the public," which would not accomplish the legislature's purpose and comport with its public policy within the context of the regulatory circumstances would be inappropriate and held that even when a service is offered to a select and limited class of persons, it could still be an offering to the public depending on the regulatory circumstances at issue. Some of the regulatory circumstances to consider in the context of the Petition are: (1) the nature of the regulated industry, (2) the market served by the industry, (3) the kind of competition in the market, and (4) the effect on the industry of non-regulation of

Bishops Ridge HOA as a residential water service provider. See Simpson, 295 N.C. at 524, 246 S.E. 2d at 756.

In North Carolina, the residential water utility industry consists largely of municipal or government-owned service providers and private investor-owned providers. The government-owned systems are regulated by local elected governing boards and the investor-owned systems are regulated by the Commission pursuant to Chapter 62. Investor-owned water utility providers serve approximately 126,000 household accounts in North Carolina. Hence, in a state with an adult population of more than 7.5 million, the private investor-owned residential water industry is relatively small and serves a small segment of the market of customers who need the protections provided in Chapter 62 and who live primarily in subdivisions or communities, which for a number of reasons are not able to receive water service from a government-owned system or from their own private water source. The competition in these market areas is limited to non-existent in that it is not economically or practicably feasible for multiple private providers to own and install competing water systems designed to serve the same households or relatively small communities. This is the reason willing providers are permitted to apply to the Commission to be certificated as the exclusive monopoly service providers in defined service territories. In the case of Bishops Ridge HOA, there is no other system or provider currently in position to provide uninterrupted water supply to the Phase IV Subdivision residents.

The effect of allowing homeowners' associations, such as Bishops Ridge HOA, to serve customers who are not members of their associations as non-regulated providers would be to risk shifting residential water service to an unregulated industry. This would be particularly true were the Commission to allow an exception from regulation based on classifying the service provided by a homeowners' association as a bulk water sale to an intermediary who provides no service to the end-using customer and who has no ownership in the association's water system. If the Commission were to allow Bishops Ridge HOA to escape regulation by using a "bulk water sale" to fall below the regulatory numerical threshold of 15 residential water customers when there are 59 actual end-using residential customers behind the sale, it would not take long for other regulated providers in the industry to structure their water service in a similar fashion in order to become unregulated providers of one bulk water sale customer, notwithstanding the fact that their real purpose would be to provide water service to hundreds, if not thousands, of residential customers. Such an occurrence or result would be a huge obfuscation of legislative intent to assure regulatory protections to residential water customers. Thus, in summary, Simpson, supports the Commission's recognition of the actual number of customers being served by Bishops Ridge HOA without regard to the bulk sale classification or label—especially where there is no utility provider between Bishops Ridge HOA and the customers, leaving the customers with no one to look to for protections from monopoly power other than this Commission.[1]

[1] In addition, the Commission cannot and will not accept the argument that Bishops Ridge HOA has only one customer because the party or parties most affected by the outcome of the Petition, i.e., BRIV HOA and the residents of Phase IV Subdivision, are not parties to this docket and have not communicated their position on the issues involved in the declaratory ruling request to the Commission. In their absence, the Commission will not make a decision that could forever foreclose their access to this Commission should a dispute arise between the residents of Phase IV Subdivision and their water utility provider.

Finally, in addition to citing Simpson in support of their request that Bishops Ridge HOA fall outside of the definition of a public utility, Bishops Ridge HOA and the Public Staff cited to Commission decisions concluding that providers were not public utilities based on the holding in Simpson. See May 23, 2016 Public Staff Conference Filing. The Commission has carefully reviewed each of the decisions cited by the Petitioner and the Public Staff. Those decisions are legally and factually distinguishable from the scenario presented in the Petition because they do not construe or interpret the precise language that is in question in this docket; they instead focus on certain phrasing that is common to all the different public utility definitions set forth in G.S. 62-3(23)a.1-6. Additionally, the cited decisions do not discuss pertinent provisions of G.S. 62-3(23)a.2[1] and G.S. 62-3(23)d, which address the public utility status of an entity providing water utility services to residential customers or the public utility status of a homeowners association providing water utility services to customers who are neither its members nor leaseholders of its members. Because of the unique facts and circumstances in this case, each of the aforementioned is important and must be fully considered by the Commission to make the proper decision as to the public utility status of Bishops Ridge HOA. Neither the Supreme Court nor the Commission considered these factors in making a decision as to the public utility status of the entity that was at issue in those particular decisions. As a result, none of the cited decisions provides precedent to support a finding by the Commission in this case that Bishops Ridge HOA is not operating as a public utility when it provides water utility service to the residents of the Phase IV Subdivision for compensation.[2]

Having determined that Bishops Ridge HOA is acting as a public utility when and to the extent it provides water utility service to the residents of the Phase IV Subdivision for compensation, the question now becomes what, if any, regulatory authority should the Commission exercise over Bishops Ridge HOA. Although the Commission has been granted broad and comprehensive powers to supervise and control public utilities of this State, the Commission

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[1] Three cases cited by Bishops Ridge HOA and the Public Staff in support of the request for a declaratory ruling in this case find that the entity in question would not be a public utility as the term is defined in G.S. 62-3(23)a.2. See Request for Declaratory Ruling by Pharr Yarns, LLC, Docket No. W-1260, Sub 0 (November 22, 2005), Petition for Declaratory Ruling by Grand Strand Water and Sewer Authority, Docket No. W-1278, Sub 0 (January 28, 2008), and Request for Declaratory Ruling by JUSA Utilities Bridgeton, LTD, Docket No. W-1290, Sub 0 (April 27, 2010). It is noteworthy, however, that that G.S. 62-3(23)a.2 contains two separate and distinct public utility definitions, i.e., a definition for a water public utility which is the definition in question in this case, and a definition for a sewer public utility, which was the definition in question in those cases. In G. S. 62-3(23)a.2, a sewer public utility is defined as a person owning or operating equipment or facilities for: "operating a public sewage system for compensation[.]" The sewer utility definition is fundamentally different from that of a water utility in scope and terms. The sewer utility definition is much more straight-forward without any exception or other descriptive language. The sewer utility definition is broad in scope and without limitation. By contrast, the water public utility definition is more complex, including numerical customer minimums, several different types of water service and a complex exception to the definition. These differences are vividly illustrated by the water utility definition set forth on page 3 of this Order. Because of these differences, the Commission's decisions construing the sewer utility definition and/or other public utility definitions listed in G.S. 62-3(23)a are inapposite to the facts and law of this case.

[2] Also, in each of the Commission's decisions in which the public utility definition contained in G.S. 62-3(23)a.2 was considered, the Commission included some version of the following language: "The Commission notes that this decision is limited to the facts set forth above and in the Petition and should not be regarded as precedent for any person engaging in such activities other than those presented in this case. The determination of public utility status must be made in each case on the basis of the particular facts and circumstances presented." See Request for Declaratory Ruling by JUSA Utilities Bridgeton, LTD, Docket No. W-1290, Sub 0 (April 27, 2010).

need not exercise the full measure of its authority in order to properly discharge its duties pursuant to the Public Utilities Act in every instance. Indeed, depending upon the facts of the particular case, the Commission need exercise only such power and supervision as is necessary and sufficient to carry out the laws providing for the regulation of the public utilities. *See* G.S. 62-30. Pursuant to this authority, the Commission may subject certain water utilities to only those regulatory conditions it deems appropriate if it finds that the organization and the quality of service of the utility are adequate to protect the public interest and that additional regulation is not required by the public interest, convenience and necessity.

Based upon the record heretofore presented, the Commission finds and so concludes that the quality of service provided by Bishops Ridge HOA to the Phase IV Subdivision is adequate to protect the public interest. This conclusion is supported by the Public Staff's Staff conference presentation in which the Public Staff noted that Bishops Ridge HOA secures its water from a governmental water supplier, i.e., Charlotte Water, and allows that water simply to flow through to the Phase IV residents. (Bishops Ridge HOA is, of course, duly compensated by BRIV HOA to allow this flow-through arrangement.) This arrangement is beneficial because it allows the residents of the Phase IV Subdivision to receive service from Charlotte Water without incurring the added expense that would be associated with maintaining a direct connection with Charlotte Water. Moreover, the Commission notes that Charlotte Water, as a large government owned system, has the wherewithal, resources and expertise to ensure that the water it provides to customers meets state and federal safety standards. Thus, the Commission further finds and concludes that it need not apply the full panoply of protective and regulatory measures to Bishops Ridge HOA that it would customarily apply to another entity that provides or is providing water utility service to residential customers for compensation arising from its provision of service to the residents of the Phase IV Subdivision.

However, because the residents of the Phase IV Subdivision have no ownership interest in Bishops Ridge HOA and none of the protections that come with such ownership, they are in a unique and potentially vulnerable position as to access to water service and as to rates charged for that water utility service. Unlike the member-owner residents of Bishops Ridge Subdivision, they are not able to vote for or participate in the election of the governing body of Bishops Ridge HOA.[1] They essentially have no opportunity to influence the decisions of Bishops Ridge HOA because they cannot vote for the members governing board of directors. In this circumstance, it is the Commission's duty to protect BRIV HOA and its resident-customers from the unchecked monopoly power of Bishops Ridge HOA. Among other things, the Commission is charged to protect the non-member customers in the Phase IV Subdivision from unfair discriminatory charges for water service as well as from any unwarranted or arbitrary action that would result in their being deprived of uninterrupted water supply. The Commission, therefore, deems it necessary and within its regulatory oversight authority to subject Bishops Ridge HOA, a public utility, to the

[1] The Commission observes that a key reason the General Assembly permits an HOA serving only its members to be exempt from economic regulation is that such members are protected from the utility's overreach by their membership right in the HOA, which allows them to elect the governing board of the HOA. A non-member customer being served by an HOA has no such protection and therefore an HOA serving any non-member must be subject to the oversight and regulation deemed necessary by the Commission for the adequate protection of such non-member. The General Assembly also allows the Commission to exempt a non-profit water utility from such regulatory oversight if such member-customers are allowed to elect their governing board. See G.S. 62-110.5.

following conditions with respect to the water service it provides to BRIV HOA and the residents of Phase IV Subdivision:

(1) Bishops Ridge HOA shall submit an application for a certificate of public convenience and necessity to continue providing water utility service to BRIV HOA and the residents of Phase IV Subdivision within 120 days from the date of this Order;

(2) Bishops Ridge HOA shall submit a copy of the water sale agreement that it has entered into with BRIV HOA to the Commission for review and approval within 120 days of this Order;

(3) Bishops Ridge HOA shall submit a detailed explanation of the methodology by which the rates for BRIV HOA or the residents of the Phase IV Subdivision are determined to the Commission for review and approval within 120 days of the date of this Order;

(4) If the sale agreement and rate methodology are approved, any change in the rates charged to BRIV HOA and/or to the residents of the Phase IV Subdivision thereafter shall be submitted to the Commission for review and approval within 30 days of the implementation date of the rate or ratemaking methodology change; provided that any change that is identical to a change (increase or decrease) imposed on Bishops Ridge HOA by Charlotte Water need not be approved by the Commission but must be filed with the Commission within 30 days of the implementation of the change in rates, provided further that if the Commission determines that Bishops Ridge HOA has imposed a rate that is inconsistent with the change in rates charged by Charlotte Water, such rate change is subject to refund with statutory interest if so ordered by the Commission;

(5) The rate charged by Bishops Ridge HOA to BRIV HOA shall reflect the rate charged to Bishops Ridge HOA by Charlotte Water. Therefore, Bishops Ridge HOA shall change the rate charged to BRIV HOA to reflect any decrease in rates afforded it by Charlotte Water and any increase in rates charged to it by Charlotte Water; and,

(6) The terms and conditions set forth in G.S. 62-118, and G.S. 62-60 through G.S. 62-81, respectively, and Commission Rules R7-17, R7-19 and R7-20 are applicable to Bishops Ridge HOA.

As the Commission noted in the preceding discussion, it is subjecting Bishops Ridge HOA to the specific enumerated conditions above because on the record before the Commission, Bishops Ridge HOA was and is providing water utility service to the residents of Phase IV Subdivision, none of whom is a member or leasehold of a member of Bishops Ridge HOA.. However, nothing in the record here presented or the decision of the Commission precludes Bishops Ridge HOA and BRIV HOA and their member-residents from forming a non-profit water utility, which upon application, could potentially be exempted from regulation under G.S. 62-110.5, or, alternatively, nothing prevents the two HOAs from joining together as one association, which would be exempt from regulation automatically under the homeowners' exemption of G.S.62-3(23)d.

Accordingly, for the reasons stated above, the Commission denies the Petitioner's request that the Commission find that it is not a public utility and on its own motion, finds, concludes and so declares that Bishops Ridge HOA is a public utility subject to the regulatory conditions set forth in this Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of April, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

Commissioner Bryan E. Beatty did not participate in this decision.

DOCKET NO. W-1309, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition for Declaratory Ruling by The Villages of Bishops Ridge Association	)))	ORDER DENYING PETITION FOR RECONSIDERATION AND STAY OF ENFORCEMENT

BY THE COMMISSION: On August 17, 2015, the Villages of Bishops Ridge Association[1] (Bishops Ridge HOA or Petitioner) filed a Petition requesting a declaratory ruling that by providing bulk water to the adjacent Village of Bishops Ridge IV Association[2] (BRIV HOA), "Bishops Ridge is not a public utility within the meaning of G.S. 62-3(23), does not own or operate in this State equipment or facilities for '[d]iverting, developing, pumping, impounding, distributing or furnishing water to or for the public for compensation, and is not a utility as defined in Commission Rule R7." Petition, p. 1.

On May 23, 2016, the Public Staff presented this matter at the Commission's Regular Staff Conference. The Public Staff stated that, in its opinion, Bishops Ridge HOA is not a public utility

[1] Bishops Ridge HOA is a non-profit corporation formed pursuant to Chapter 55A of the North Carolina General Statutes. Bishops Ridge HOA serves as the homeowners association for the residents of Bishops Ridge Subdivision. The residents and leaseholders of residents of Bishops Ridge Subdivision are member-owners of Bishops Ridge HOA.

[2] BRIV HOA is a non-profit corporation formed pursuant to Chapter 55A of the North Carolina General Statutes. BRIV HOA serves as the homeowners association for the residents of the Phase IV Subdivision. The residents and leaseholders of residents of the Phase IV Subdivision are resident-members of BRIV HOA. Neither BRIV HOA nor its resident-members are members of Bishops Ridge HOA. Thus, BRIV HOA and/or the resident-members of BRIV HOA are a non-member customer and/or non-member customers of Bishops Ridge HOA.

as defined in G.S. 62-3(23)a.2 or a utility as set forth in Commission Rule R7-2(a). The Public Staff thereafter requested that the Commission issue a declaratory ruling to that effect.

On April 24, 2017, the Commission issued an Order Issuing Declaratory Ruling (DRO). In the DRO, the Commission held that Bishops Ridge HOA is a public utility as the term is defined in G.S. 62-3(23)a.2 when it uses its facilities to furnish water utility service to 59 non-member customers residing in the Phase IV Subdivision for compensation.

On April 29, 2017, pursuant to G.S. 62-80, Bishops Ridge HOA filed a Petition for Reconsideration and Stay of the Enforcement of the Commission's Declaratory Ruling Order (the PR&S). In the PR&S, Bishops Ridge HOA stated that "[it] believes that clarification of certain information related to the method by which it provides water to the adjacent Bishops Ridge IV Association ("BRIV") supports a reversal of the Utilities Commission's determination that [Bishops Ridge HOA] is a public utility as that term is defined in G.S. 62-3(23)." In support of the PR&S, Bishops Ridge HOA asserted the following clarifications:

(1) Bishops Ridge HOA only passes the pro rata portion of the monthly water bill that it receives from Charlotte Water to BRIV HOA. Bishops Ridge HOA does not add any upcharge, compensation or profit to the bill that it provides to BRIV HOA. Therefore, Bishops Ridge is not providing water to BRIV HOA for compensation and does not fall within the definition of a public utility set forth in G. S. 62-3(23).

(2) Bishops Ridge HOA does not collect any money directly from residents in the Phase IV Subdivision for water used by those residents and is not authorized to shut off water to any home in Phase IV Subdivision for the failure of the occupant to pay his/her assessment to BRIV HOA.

(3) Bishops Ridge is not responsible for maintaining water distribution lines outside of the Bishops Ridge Subdivision. Bishops Ridge HOA does not maintain or repair any water distribution lines inside of the Phase IV Subdivision. Bishops Ridge HOA does not own any real estate or have an easement over any real estate upon which the distribution lines run in the Phase IV Subdivision. BRIV HOA has exclusive ownership, control and responsibility for repairing any damage to water distribution lines within the Phase IV Subdivision.

(4) Forcing Bishops Ridge HOA to operate as a public utility would result in significant additional costs for water utility service to Bishops Ridge HOA and BRIV HOA because Bishops Ridge HOA would be authorized to recover reasonable operating expenses as well as a reasonable rate of return from BRIV HOA when it provides water to BRIV HOA and the residents of the Phase IV Subdivision.

(5) Charlotte Water already includes costs for administration and profit in its bills to Bishops Ridge HOA. If Bishops Ridge HOA is forced to act as a public utility, Bishops Ridge HOA would also charge for its administrative costs and profits. Charging for costs and profits in the manner described would be duplicative and would negatively and financially impact all water users.

(6) Because it is a nonprofit organization which is managed by a volunteer board of directors made up of residents of the community, Bishops Ridge HOA is simply not administratively able to operate as a public utility.

(7) Bishops Ridge HOA does not offer water sales to the public and does not allow water to run through its pipes to any other community or person.

(8) Bishops Ridge HOA has no ability to control the price of water that it purchases from Charlotte Water and provides to BRIV HOA since that price is set by Charlotte Water without input from Bishops Ridge HOA.

(9) Charlotte Water is a heavily regulated public authority subject to regulatory oversight and consumer protection by the North Carolina Utilities Commission. Therefore, no further regulation of the arrangement between Bishops Ridge HOA and BRIV HOA is necessary.

(10) Bishops Ridge HOA is ready and willing to execute any Commission approved agreement or other necessary documentation with BRIV HOA to clarify that the method by which water flows through Bishops Ridge HOA will not make Bishops Ridge HOA a public utility and to ensure that the water users in the Phase IV Subdivision are not negatively impacted by the arrangement.

(11) The consent and support of BRIV HOA's Board of Directors is evidenced by the Board President's signature on the PR&S.

After listing the aforementioned clarifications, Bishops Ridge HOA respectfully requested that the Commission reconsider the DRO that Bishops Ridge HOA was a public utility, stay all obligations with that Order pending review and enter an Amended Order finding that Bishops Ridge HOA is not a public utility subject to regulation by the Commission.

On November 30, 2017, the Public Staff filed Comments on the Petition for Reconsideration and Stay of Enforcement (Comments). In its Comments, the Public Staff recommended that the Commission reconsider the DRO and enter an amended Order finding that Bishops Ridge HOA is not a public utility subject to regulation by the Commission. In support of its recommendation, the Public Staff stated that the decision should be reversed because:

(1) Bishops Ridge HOA's responsibility for providing water to BRIV HOA and/or the residents of the Phase IV Subdivision ends at the points of delivery at the boundary line with the Phase IV Subdivision. Therefore, Bishops Ridge HOA does not own, operate, maintain or repair the water distribution mains or water service lines within the Phase IV Subdivision. The responsibility for meeting those obligations within the Phase IV Subdivision belong to BRIV HOA, the owner and operator of the distribution lines and water mains within the Phase IV Subdivision. As a homeowners association, BRIV HOA is exempt from regulation by the Commission pursuant to G.S. 62-3(23). These facts were not presented to the Commission prior to the Commission's DRO.

(2) All water for the Bishops Ridge Subdivision and the Phase IV subdivision is purchased from Charlotte Water, which issues a monthly water bill to Bishops Ridge HOA. BRIV HOA pays a prorated share of the Charlotte Water bill to Bishops Ridge HOA each month based upon an agreed upon formula established in 2007 which was developed through mediation between the two HOA's with assistance from the Public Staff. The 2007 agreement has been in continuous use since that time and is considered fair and reasonable by Bishops Ridge HOA and BRIV HOA. These facts were not presented to the Commission prior to the DRO.

(3) BRIV HOA has executed the Bishops Ridge's PR&S concurring in the request that the Commission reconsider its order and declare that Bishops Ridge HOA is not a public utility subject to regulation by the Commission.

(4) Bishops Ridge HOA provides water to BRIV HOA and not to the homeowners' residing in the Phase IV Subdivision. The monthly Charlotte Water bill is prorated without markup or fees paid to Bishops Ridge HOA. Therefore, Bishops Ridge HOA does not receive compensation for providing water to BRIV HOA which is a required element in the definition of a water public utility in G.S. 62-3(23)a.2.

(5) BRIV HOA pays the full agreed upon monthly prorated price for water, regardless of whether all of the Phase IV residents have paid their individual BRIV HOA assessments.[1] Bishops Ridge HOA has no dealings with or responsibilities to the residents of Phase IV Subdivision.

(6) Bishops Ridge HOA does not offer water service to the public. Bishops Ridge HOA only passes through the purchased costs of water from Charlotte Water to only one entity, BRIV HOA with a predetermined cost sharing proration.

(7) Charlotte Water is not regulated by the Commission. Due to economies of scale, Charlotte Water's rates are significantly below the average water rates in North Carolina. The Commission's regulation of Bishops Ridge HOA as a water public utility with the required reports, would increase operating costs thereby unnecessarily increasing the amounts the residents of Bishops Ridge Subdivision and Phase IV Subdivision pay for service.

The Public Staff thereafter recommended that the Commission reconsider the decision that Bishops Ridge HOA was a public utility, and enter an Amended Order finding that Bishops Ridge HOA is not a public utility.

[1] In the Public Staff's Comments, Paragraph 4 states that "[t]he BR IV Association pays to the BR POA the full agreed upon monthly proration, regardless whether all of the BRIV Assoc. members have paid the *BR POA*." Emphasis added. This language implies that the Phase IV residents pay Bishops Ridge HOA directly. Clearly this is erroneous. BRIV HOA and the Public Staff both acknowledge that Phase IV residents do not have any direct interactions with Bishops Ridge HOA. Instead, the Phase IV residents pay their assessments directly to BRIV HOA which then pays the pro rata share of the water bill submitted by Bishops Ridge HOA. For this reason, the Commission's summary used language which correctly reflects the true nature of the payment arrangement.

DISCUSSION

Pursuant to G.S. 62-80, the Commission has broad authority "to reconsider its previously issued order, upon proper notice and hearing" and "upon the record already compiled, without requiring the institution of a new and independent proceeding by complaint or otherwise." State ex rel. Utilities Commission v. Edmisten, 291 N.C. 575, 582, 232 S.E.2d 177, 181 (1977). In exercising that authority, the Commission may rescind, alter, amend, or refuse to make any change to its earlier order. Id. An application for reconsideration pursuant to G.S 62-80 is addressed to and rests in the discretion of the Commission. State ex rel. Utilities Commission v. Services Unlimited, Inc., 9 N.C. App. 590, 591, 176 S.E.2d 870, 871 (1970).

In light of the aforementioned, the Commission has carefully considered the clarifications provided by Bishops Ridge HOA in its PR&S, the Comments filed by the Public Staff which were intended to clarify and amplify previously presented information and to add new facts and arguments that the Commission had not considered prior to the issuance of the DRO and the entirety of record. In the Commission's opinion, none of the clarifications, amplifications, new facts[1] or arguments[2] presented in Bishops Ridge HOA's and the Public Staff's filings and presentations are compelling enough to warrant the amendment, reversal or rescission of the Commission's determination that Bishops Ridge HOA is a public utility when it uses its facilities

[1] Bishops Ridge HOA and the Public Staff both now emphasize that BRIV HOA's Board of Directors is supportive of the PR&S. While the Commission finds this information helpful, it is not persuaded that the support shown by BRIV HOA's Board of Directors alleviates the Commission's concern that the Phase IV residents may be subject to overreach by Bishops Ridge HOA. As was noted in Footnote 9 in the DRO, typically individuals receiving water utility service from a homeowners' association (HOA) are protected from the HOA's overreach by their membership right in the HOA, which allows them to elect the governing board of the HOA. As non-members of the Bishops Ridge HOA, neither BRIV HOA nor the residents of the Phase IV Subdivision have this right. In that circumstance, the Commission held that a "HOA serving a non-member must be subject to oversight and regulation deemed necessary by the Commission for adequate protection of such non-member." See Footnote 9 DRO.

[2] In their post decision filings both Bishops Ridge HOA and the Public Staff for the first time argue that because the prorated payment that BRIV HOA makes to Bishops Ridge HOA for its share of the Charlotte Water bill does not include a markup, upcharge, fees or profit, Bishops Ridge HOA does not receive compensation, i.e., a required element in the definition of a water public utility in G.S. 62-3(23)a.2. There is no merit to this argument.

The term "compensation" is not defined in G.S. 62-3(23)a.2. When the statute is silent as to the definition of a word, the term must be given its ordinary meaning. The American Heritage Dictionary, Third Edition (1997) defines the word "compensate" thusly: To make satisfactory payment or reparation to; recompense or reimburse. Similarly, it defines the word "compensation" as: Something given or received as payment or compensation. Clearly, the payment arrangement that Bishops Ridge HOA has with BRIV HOA falls within the confines of these two definitions even if it does not include any markup, upcharge, fees or profits.

to furnish water utility service to 59 non-member customers residing in the Phase IV Subdivision for compensation. Thus, for the reasons articulated herein, the Commission, it its discretion, finds and so concludes that Bishops Ridge HOA's Petition for Reconsideration and Stay of the Enforcement of the Commission's Declaratory Ruling must be and is hereby denied.

IT IS, THEREFORE, SO ORDERED.[1]

ISSUED BY ORDER OF THE COMMISSION.
This the __15th__ day of December, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

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[1] In the PR&S, Bishops Ridge HOA requested that the Commission stay any actions required by the DRO pending review of its Petition. To the extent that the DRO was stayed, such stay is lifted by this Order. Bishops Ridge HOA is therefore required to comply with the terms and conditions set forth in the DRO from the date of this Order.

DOCKET NO. W-390, SUB 13

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Request by the Public Staff – North Carolina Utilities Commission for the Appointment of Carolina Water Service, Inc. of North Carolina as Emergency Operator of the Riverbend Estates Water System in Macon County, North Carolina	))))))	ORDER APPOINTING EMERGENCY OPERATOR, APPROVING INCREASED RATES, AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On May 9, 2017, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a Petition pursuant to G.S. 62-116(b) and G.S. 62-118(b), requesting the Commission issue an order: (1) declaring an emergency, (2) appointing Carolina Water Service, Inc. of North Carolina (Carolina Water) as emergency operator, and (3) approving an emergency rate increase on a provisional basis for the water system serving Riverbend Estates in Macon County, North Carolina.

Based upon the Public Staff's petition and the Commission's records, the Commission makes the following

FINDINGS OF FACT

1. On February 22, 1973, in Docket No. W-390, Sub 0, the Commission issued a Show Cause Order to Calvin Henson, the original developer of the Riverbend Estates Subdivision, for failure to obtain a franchise for the Riverbend Estates water utility system in Macon County. Subsequently, Calvin Henson did file an application for a certificate of public convenience and necessity in Docket No. W-390, Sub 1, and on April 1, 1974, the Commission issued an Order Dismissing Show Cause Order.

2. The Commission by Order dated July 9, 1974, in Docket No. W-390, Sub 1, required additional information to support the franchise application filed by Riverbend Estates, Inc., T/A Riverbend Estates Water System, Finding of Fact No. 2 stated:

> "2. The water system in Riverbend Estates as it now exists does not meet the Standards of the Division of Health Services. The Applicant has not received approval of its water system plans from the State Division of Health Services."

The Commission issued Order Granting Temporary Operating Authority to Riverbend Estates, Inc., T/A Riverbend Estates Water System dated December 4, 1974, which ordered the applicant to complete system improvements to bring the water system up to Division of Health Service (DHS) standards.

3. The Commission in Docket No. W-390, Sub 2, by Order dated September 15, 1978, approved the transfer of the Riverbend Estates water system to Sportsland, Inc., T/A Riverbend Estates Water System (Sportsland) and also granted Sportsland temporary operating authority. Sportsland obtained the water system as part of the purchase of Riverbend Estates Subdivision.

4. By Order dated December 10, 1982, in Docket No. W-390, Sub 4, the Commission approved the transfer of the water system from Sportsland to Riverbend Water System, Inc., whose President was Albert Rudisill, who operated a local pump service and well supply business and had previously made improvements to the water system for Sportsland. The system was experiencing excessive iron in a new well and engineering plans for the system improvements made by Sportsland had not been submitted for approval to the North Carolina Department of Human Resources. Riverbend Water System, Inc., was granted temporary operating authority and Riverbend Water System, Inc., was ordered to

> "proceed with measures to correct the excessive iron problem and ... obtain approval of the Riverbend Estates Water System from the Department of Human Resources."

5. On February 25, 1987, in Docket No. W-390, Sub 5, the Commission issued an Order in the complaint proceeding filed by a customer alleging the water system was rundown and in need of immediate repair, that there were frequent service interruptions, that the water quality was poor due to a high iron content, and that Riverbend Water System, Inc., had not made the system corrections ordered by the Commission in Docket No. W-390, Sub 4. In addition, Albert Rudisill, the President of Riverbend Water System, Inc., had moved to Florida, and it had been difficult for customers to contact him when problems were encountered. The water system still had not received DHS approval even though the Commission's Order dated December 10, 1982, required upgrading so that the water system would satisfy DHS standards. The only DHS approval was for the original system approved to serve only 28 connections, but in 1987 the system was serving 90 connections. No plans had been approved by DHS since the Commission's December 10, 1982 Order, in Docket No. W-390, Sub 4, nor had the iron problem been corrected.

The Hearing Examiner's Order dated February 25, 1987, ordered Riverbend Water System, Inc., to

a. Obtain DHS plan approval and construct system improvements to comply with the DHS approved plans;

b. Provide the local qualified operator authority to repair or replace broken water lines and pumps to avoid pressure problems or loss of water to customers;

c. Provide adequate storage capacity, well yield, water quality, and flushing to remove accumulated iron deposits in the mains; and

d. There be no new service connections until authorized by DHS.

6. On October 7, 1987, in Docket No. W-390, Sub 6, the Commission issued Order Approving Stock Transfer approving Albert Rudisill transferring his 100% of the stock in Riverbend Water System, Inc., 50% to Ronald L. Hardegree, and 50% to Geraldine M. Hardegree (Hardegrees). The Hardegrees stated they would make the improvements as required in the February 25, 1987, Order as follows:

a. Have engineers update as-built plans and get them approved by DHS;

b. Filter the high yield well for iron or drill another well if iron filtering cannot feasibly be done;

c. Install 20,000 gallons more storage (in addition to the current 20,000 gallons);

d. Install new main as needed (as engineer recommends);

e. Provide 24-hour service man and truck using Rudisill Pump Service or other qualified sub-contractors having specialty equipment that would not be feasible for the Hardegrees to own (when needed); and

f. Meter all customers.

7.a. Riverbend Water System, Inc., filed a general rate case in 1989, in Docket No. W-390, Sub 8. The Hearing Examiner in the Order dated April 24, 1989, stated in Finding of Fact No. 5 that

"The Company is presently providing adequate service to its customers."

b. Andy Lee, the Director of the Public Staff Water Division, testified that the Hardegrees had completed all the Commission required improvements in the Order dated October 7, 1987, with the exception of metering all the customers. Andy Lee testified

> "As built plans specifying improvements have been submitted and approved by the Department of Health Services (DHS). The high yield well has been recased and berm filters have been installed to remove excess iron. An additional 20,000 gallons of ground storage has been added bringing the total storage to 40,000 gallons. New mains have been installed to tie all wells directly to the storage tanks. A new electrical control system has been installed to operate and control the well and filtering system more efficiently. Twenty-four hour service is being provided. Five meters have been installed leaving 92 meters to be installed.
>
> At the end of the test year period, September 30, 1988, the Hardegrees had invested $41,781 in capital for improvements to the system."

8. In the general rate case Order dated July 9, 1998, Docket No. W-390, Sub 9, Hearing Examiner Stallings found in Finding of Fact No. 2 that Riverbend Water System, Inc., was providing adequate service. However, customers testified that at certain times their water was

red or brown. Andy Lee outlined in his affidavit how improved filter operations and distribution system flushing could improve the water quality. Andy Lee stated that the Hardegrees had installed well filters and began flushing the system, both of which had improved the water quality.

9. In the next general rate case in Docket No. W-390, Sub 10, with hearing held on July 23, 2002, several customers testified they had experienced episodes of brown or discolored water coming from their faucets and other plumbing fixtures. Riverbend Water System, Inc., had installed an iron removal filter and was flushing the distribution system monthly. Hearing Examiner Stallings found in the Order dated September 12, 2002, in Finding of Fact No. 14

> "The water utility system serving Riverbend Estates Subdivision is compliant with the NC Department of Environment and Natural Resources Division of Environmental Health, and the Applicant is providing adequate water utility service. However, customers are continuing to experience slugs of brown water on a periodic basis, primarily the result of sediment build-up in the distribution mains. The Company should investigate and report to the Commission on the practicability, effectiveness and cost of remedying this problem through each of the following approaches; (1) sequestration; (2) scouring or cleaning the mains; and (3) purchasing water from the Town of Franklin."

10.a. In the summer of 2012, the Town of Franklin bulk purchased water interconnection was completed and the Town of Franklin began to sell bulk metered water to the Riverbend Estates water system. Prior to the interconnection, the customers continued to experience discolored water and staining from iron. In addition, the wells had struggled to meet the demand. The Hardegrees had transferred the water system to a newly formed corporation Riverbend Estates Water System, Inc. (REWS), in which the Hardegrees owned 100% of the stock.

b. The Order Granting Franchise, Granting Partial Rate Increase, and Requiring Customer Notice dated February 26, 2013, in Docket No. W-390, Sub 11, granted a certificate of public convenience and necessity to REWS and a rate increase to include the expenses relating to purchased bulk water from the Town of Franklin. No customers protested the applied for increase.

c. The Commission approved the metered rates as follows:

Monthly base charge, zero usage:	$19.52
Usage charge, per 1,000 gallons:	$ 5.00

The annual purchased water expense included in this rate case was $40,228, based upon average residential customer usage of 4,200 gallons per month, plus 10% water loss, and the Town of Franklin's water usage rate of $5.00 per 1,000 gallons, plus a monthly base charge for a four-inch water meter of $440.

11. The current bulk water rate the Town of Franklin charges REWS is a monthly base charge $589.70, which includes 24,000 gallons minimum, and usage charge per 1,000 gallons of $6.60. The Public Staff Water Division on two occasions advised and provided instructions with

a sample filing to Ronald Hardegree for the filing of a purchased water pass through rate increase. However, REWS has not filed for a pass through.

12. Beginning in August 2015, REWS only made partial purchased bulk water payments each month to the Town of Franklin. The past due balances increased monthly, with only a few exceptions. As of June 10, 2016, REWS was indebted to the Town of Franklin in the amount of $13,995 of which $11,347 was past due. Mrs. Hardegree executed a payment agreement with the Town of Franklin dated June 10, 2016, with an agreed upon payment plan to pay the current bill each month plus $500 each week of the arrearage. However, REWS did not comply with the agreement.

13. By letter dated October 10, 2016, the Town of Franklin advised Mr. and Mrs. Hardegree that they owed the town $27,987, and the bulk water would be disconnected if the account was not paid in full by November 10, 2016. The Town of Franklin's bulk water is the only water source for the Riverbend Estates water system as the wells were disconnected in the summer of 2012.

14. REWS sent to the 131 residential customers a letter dated October 31, 2016, stating that the company was at risk of closing in the next 30 days. The letter stated customers should make arrangements to start a personal account with the Town of Franklin, and if that is not an option, to drill a water well for their residences.

15. An emergency exists in the Riverbend Estates water system as REWS has threatened abandonment and should the Town of Franklin discontinue for non-payment the bulk water deliveries, the 131 residential customers would be completely without water utility service.

16. Carolina Water has approximately 40 years' experience managing and operating water systems in the North Carolina mountains. Currently Carolina Water manages and operates mountain water systems in the following North Carolina counties: Alleghany, Avery, Buncombe, Cherokee, Henderson, Jackson, Madison, Macon, Rutherford, Transylvania, Watauga, and Yancey. The Public Staff advised the Commission that the Public Staff believes Carolina Water is well qualified to be the emergency operator and is willing to perform the emergency service.

17. REWS has advised the Public Staff that REWS consents to Carolina Water being appointed emergency operator.

18. Carolina Water has agreed to be appointed emergency operator effective May 16, 2017. However, Carolina Water has requested that the Commission's Order appointing Carolina Water emergency operator clearly state:

a. That Carolina Water as emergency operator shall not be responsible for, or liable for, any acts, omissions, system operations and maintenance, or system installations, occurring prior to the date of the appointment as emergency operator, with the exception of payments to the Town of Franklin for arrearages for purchased bulk water as described in Findings of Fact Nos. 12, 13, and 24.

b. That Carolina Water as emergency operator may petition the Commission at any time to be discharged as the emergency operator, which discharge the Commission shall approve.

The Public Staff stated it fully supports the inclusion of both those provisions in the Commission's Order appointing Carolina Water as emergency operator.

19.a. The REWS customer rates for the Riverbend Estates system including purchased water from the Town of Franklin were approved in general rate case Order dated February 13, 2013, Docket No. W-390, Sub 11, and were:

Metered Monthly Rates (Residential Service)

Base charge, zero usage	$19.52
Usage charge, per 1,000 gallons	$ 5.00

b. The Commission approved rates for REWS were reduced by Order dated October 13, 2015, Docket No. W-390, Sub 12, for the repeal of the gross receipts tax, by Order dated May 26, 2016, Docket No. W-390, Sub 12, for the reduction to 4% of the North Carolina corporate income tax rate, and by Order dated December 12, 2016, in Docket No. W-390, Sub 12, for the reduction in the North Carolina corporate income tax rate to 3%. The current Commission approved rates for REWS are:

Metered Monthly Rates (Residential Service)

Base charge, zero usage	$18.67
Usage charge, per 1,000 gallons	$ 4.79

The average monthly residential customer water bill is $38.79 based upon the REWS current rates and the 4,200 gallons average monthly consumption from the most recent REWS general rate case decided in 2013.

20. The REWS 2016 Annual Report reflects for 2016 a net operating loss of $735, excluding accrued interest, and also excluding the arrearage owed to the Town of Franklin for purchased bulk water.

21.a. The Public Staff stated it believes the expenses listed on the REWS 2016 Annual Report do not include all the operational costs necessary to provide adequate service and for the Riverbend Estates water system to be operated in compliance with the Rules Governing Public Water Systems. The Public Staff stated it believes the net operating losses in 2016 were significantly larger than the listed net loss of $735, as the price for purchased water from the Town of Franklin increased on July 1, 2016, and the Public Staff stated there has probably been a substantial increase in unaccounted-for water.

b. The REWS 2016 Annual Report income statement appears to be on a modified cash basis rather than a more accurate accrual basis. For example, the 2016 Annual Report lists the purchased bulk water expense at $26,500. However, the Town of Franklin billed REWS for purchased bulk water during calendar year 2016 a total of $67,465, and the Town of Franklin received purchased water payments from REWS during calendar year 2016 totaling $44,471.

22. The Public Staff recommended that the Commission approve a significant immediate emergency rate increase so the emergency operator, Carolina Water, will have adequate funds to operate the system, perform necessary administrative functions, provide the necessary supplies, repair parts, replacement meters, limited system improvements, pay the Town of Franklin for the purchased bulk water including payments on the arrearage, perform a distribution audit to reduce the unaccounted-for water, and have reserves for emergencies.

23. The Public Staff recommended the Commission approve on a provisional basis, an emergency rate increase with the following rates:

Metered Rates (Residential Service)

Monthly base charge, zero usage	$35.00
Usage charge, per 1,000 gallons	$11.95

These Public Staff recommended rates include a 7.5% operating margin on operating revenue deductions.

These Public Staff recommended rates will increase the average monthly residential bill 120% from $38.79 to $85.19 based upon the average monthly residential consumption of 4,200 gallons.

24. The most recent REWS purchased water indebtedness to the Town of Franklin dated April 27, 2017, reflects a balance due of $46,995, which includes the April 21, 2017, billing of $4,433 to REWS. After consultations with the Public Staff in October 2016, the Town of Franklin after learning the Public Staff would recommend to the Commission the appointment of an emergency operator, suspended the process to discontinue for non-payment the bulk water deliveries to the Riverbend Estates water system (the only source of potable water to the customers).

25. The Public Staff recommended in order to ensure continued water service to the 131 residential customers, that the Commission order the emergency operator to make installment monthly payments of $1,500 on the arrearage to the Town of Franklin, beginning on November 15, 2017, which payment would continue until the purchased water arrearage is paid in full. The six-month delay in the commencement of payments, the Public Staff stated should enable Carolina Water to complete its distribution system unaccounted-for water audit and make the necessary repairs, renovations and replacements which should materially decrease the amounts of purchased monthly bulk water deliveries from the Town of Franklin. If there is later appointed a successor emergency operator, then that emergency operator would continue the $1,500 monthly purchased water arrearage payments until the arrearage is paid in full.

26. The emergency operator will also pay the Town of Franklin each month the current purchased bulk water bill.

27. Riverbend Estates Water System, Inc., does not have a bond posted with the Commission.

CONCLUSIONS

Based upon the foregoing and the recommendations of the Public Staff, the Commission concludes that an emergency exists for the Riverbend Estates water system which is in imminent danger of losing adequate water utility service. The Commission further concludes that Carolina Water should be appointed emergency operator and the Public Staff recommended rate increase on a provisional basis should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That Carolina Water Service, Inc. of North Carolina is hereby appointed as emergency operator of the Riverbend Estates water system, effective May 16, 2017.

2. That a copy of this Order and Schedule of Rates, attached as Appendix A, shall be mailed with sufficient postage or hand delivered by Carolina Water to all customers served by the Riverbend Estates water system, no later than 15 days after the date of this Order and that Carolina Water shall submit to the Commission the attached Certificate of Service properly signed and notarized not later than 20 days after the date of this Order.

3. That the Schedule of Rates, attached as Appendix A, is approved effective May 16, 2017, on a provisional basis for water utility service provided by Carolina Water as emergency operator of the Riverbend Estates water system, and subject to refund of any amounts found unjust and unreasonable.

4. That the following provisions are adopted by this Order:

a. That the emergency operator shall maintain full records of receipts and expenses and shall file with the Commission and Public Staff, by the end of the subsequent month, a summary financial report on a quarterly basis. The first report shall be filed on or before July 31, 2017.

b. Full records of receipts and expenses shall be made available to the Commission and Public Staff upon request, and include the following:

i. Copies of receipts and payments for all expenses and capital improvements incurred as part of emergency operation of the system.

ii. Weekly ledger of field operator time to/from system and time spent on-site.

iii. Maintenance, repair, and capital improvements labor and material receipts.

c. That Carolina Water as the emergency operator shall have exclusive charge of the daily operation of the Riverbend Estates water system, instead of the owner(s) of REWS. Carolina Water's duties and responsibilities acting as emergency operator shall include, among others, the following:

i. Regular inspections and testing of the Riverbend Estates water system in Macon County;

ii. Billing of all customers and collection of bills;

iii. Routine and emergency maintenance and repair;

iv. System renovations and additions necessary to maintain adequate water service;

v. Quarterly accounting to the Utilities Commission and the Public Staff of all rates collected, expenses incurred, checks written, and all monies spent; and

vi. Providing a telephone number to customers for routine and emergency calls and a mailing address.

d. That the owner(s) of REWS shall not

i. Interfere with the emergency operator's operation of the water utility plant;

ii. Receive or attempt to collect any water bill payments or monies for water utility service;

iii. Alter, impair, or remove any of the water utility plant; or

iv. Dispose or divest itself of any utility property, real or personal, without the prior consent of the Utilities Commission.

e. That the emergency operator may contract with any person to carry out any of the duties necessary for operation and repair of the water utility system, but the emergency operator shall have the ultimate, sole responsibility to see that such duties are carried out.

f. That the emergency operator in the performance of its duties, shall be free to seek assistance from customers of the water system, plumbers, engineers, attorneys, and such other persons as may be necessary for the performance of its duties and responsibilities.

g. That the emergency operator shall, when it becomes necessary in the performance of its duties, seek the assistance of the Public Water Supply Section of the Department of Environmental Quality, the North Carolina Utilities Commission, the Public Staff of the Utilities Commission, and the Macon County Health Department.

h. That the emergency operator shall collect from the customers of the water system such rates, assessments, and surcharges as may be approved by the North Carolina Utilities Commission and shall be fully authorized to bill and collect those rates, assessments, and surcharges and to disburse those funds as may be necessary to provide safe, reliable, and adequate water utility service to the customers. Any customer who fails to pay the bill(s) authorized by this paragraph shall be disconnected by the emergency operator as provided by the orders, rules, and regulations of the North Carolina Utilities Commission.

i. That the emergency operator shall be entitled to all available records relating to the water utility system and those records shall include, but not be limited to, a list of customer names, addresses, and billing records. REWS shall provide to Carolina Water all customer records within three days of the date of this Order.

j. That the emergency operator shall keep records of all monies collected through the rates, assessments (if any), and surcharges (if any), and all monies expended in the operation of the water system. In order to protect the customers' interests in the water utility system, the emergency operator is required to keep a separate record of all monies and assessments collected from customers and expended on improving and upgrading the water utility system, whether performed by the emergency operator or contractor hired by the emergency operator.

k. The emergency operator shall account for any funds advanced by it for operation of the water utility system.

l. That Carolina Water as the emergency operator beginning November 15, 2017, shall make installment monthly payments to the Town of Franklin of $1,500 on the purchased water arrearage, which payments shall continue until the purchased water arrearage is paid in full. If there is later appointed a successor emergency operator, then that emergency operator shall continue the $1,500 monthly purchased water arrearage payments until the arrearage is paid in full.

m. The emergency operator each month shall pay the Town of Franklin the current purchased bulk water bill.

n. That as the emergency operator will be paying the significant purchased bulk water arrearages to the Town of Franklin, all Riverbend Estates water system accounts receivable from customers, both billed and accrued and not yet billed on the effective date of this Order, shall be received and retained by the emergency operator and used for the payment of the purchased water arrearage.

o. As stated in Finding of Fact No. 4.k., the emergency operator shall make payments to the Town of Franklin for purchased bulk water charges incurred prior to the appointment of Carolina Water as emergency operator. With the exception of the purchased water payments to the Town of Franklin, the emergency operator shall be responsible for and pay only those liabilities arising from the emergency operator's operation of the Riverbend Estates water system pursuant to Commission Order. The emergency operator shall not be responsible for, or liable for, any acts, omissions, system operations and maintenance, or system installations, occurring prior to the date of the appointment as emergency operator. The disbursements by the emergency operator shall be made from the separate account set up by the emergency operator; the emergency operator shall account for any funds advanced by it for the operations.

p. That the emergency operator may petition the Commission at any time to be discharged as the emergency operator of the Riverbend Estates water system, which discharge the Commission shall approve. Prior to its discharge, the emergency operator shall provide an acceptable accounting to the Utilities Commission of all monies collected and disbursed during its tenure as emergency operator, as well as the amounts due and owing the emergency operator at the time of its discharge for its services performed as emergency operator. The emergency operator filing a petition for discharge shall also mail a copy of the petition to the Macon County Health Department, the Town of Franklin, and the Public Water Supply Section (PWSS) of the North Carolina Department of Environmental Quality.

q. That this docket shall remain open for further motions, reports, etc., of the emergency operator, the PWSS, the Public Staff and for further orders of the Commission.

5. That the following items of information shall be provided by REWS to Carolina Water within three business days of the effective date of the emergency operator appointment:

a. Customer information for each residence connected to the water system, containing at a minimum, customer name, service address, billing address, contact phone numbers (home and work), and billing records.

6. That the following items of information shall be provided by REWS to Carolina Water within 10 business days of the effective date of the emergency operator appointment:

a. Copy of the water system plans and specifications.

b. Copies of all monitoring reports and evaluations completed by Riverbend Estates Water System, Inc., or its certified operator for the past 24 months.

c. The names, addresses, and telephone number of all vendors providing materials and supplies for the water system operations.

d. Copies of all 2015 and 2016 property tax bills.

e. Copies of all 2016 and 2017 purchased bulk water bills from the Town of Franklin.

7. That the Chief Clerk of the Commission shall mail a copy of this Order to the Town of Franklin, 95 East Main Street, Franklin, North Carolina 28734.

ISSUED BY ORDER OF THE COMMISSION.
This the 16th day of May, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

Commissioner Jerry C. Dockham did not participate in this decision.

APPENDIX A

SCHEDULE OF PROVISIONAL RATES

for

RIVERBEND ESTATES WATER SYSTEMS, INC.
(Carolina Water Service, Inc. of North Carolina, Emergency Operator)

for providing water utility service in

RIVERBEND ESTATES SUBDIVISION

Macon County, North Carolina

WATER RATES AND CHARGES

Metered Rates: (Residential Service)

Monthly base charge, zero usage	$35.00
Usage charge, per 1,000 gallons	$11.95

Connection Charge:

$1,000 plus actual cost to connect to the Town of Franklin

Reconnection Charge:

If water service cut off by utility for good cause	$27.00
If water service discontinued at customer's request	$27.00

If water service is reconnected to the same customer at the same address within nine months of disconnection, then the reconnection charge shall be the base charge times the number of months disconnected.

New Water Customer Charge:	$27.00
Bills Due:	On billing date
Bills Past Due:	25 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
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.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-390, Sub 13, on this the 16th day of May, 2017.

WATER AND SEWER – EMERGENCY OPERATOR

CERTIFICATE OF SERVICE

I, ______________________________________, mailed with sufficient postage or hand delivered to all affected customers a copy of the Order issued by the North Carolina Utilities Commission in Docket No. W-390, Sub 13, and such Order was mailed or hand delivered by the date specified in the Order.

This the _____ day of __________________________, 2017.

By: ______________________________________
Signature

Carolina Water Service, Inc. of North Carolina
Name of Utility Company

The above named Applicant, ______________________________, personally appeared before me this day and, being first duly sworn, says that the required copy of the Commission Order was mailed or hand delivered to all affected customers, as required by the Commission Order dated __________________________ in Docket No. W-390, Sub 13.

Witness my hand and notarial seal, this the _____ day of ______________________, 2017.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ______________________________________
Date

WATER AND SEWER – EMERGENCY OPERATOR

DOCKET NO. W-1036, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Unauthorized Abandonment of Wastewater	)	ORDER APPOINTING NEW
Utility Service in Grande Oaks Subdivision,	)	EMERGENCY OPERATOR,
Durham County, North Carolina, by	)	APPROVING RATES, REQUIRING
Sedgefield Development Corporation	)	AUDIT, AND REQUIRING
	)	CUSTOMER NOTICE

BY THE COMMISSION: On May 30, 2017, the previously appointed emergency operator Thomas Harden d/b/a LTH 3 Environmental Associates (Harden), notified the Public Staff that he was resigning as emergency operator for the Grande Oaks Subdivision wastewater system, effective July 1, 2017. Harden has served as emergency operator beyond July 1, 2017, at the request of the Public Staff. On July 7, 2017, the Public Staff filed a Motion to Appoint New Emergency Operator for the Grande Oaks wastewater utility system in Durham County.

The Public Staff presented this matter at the Commission's Staff Conference on July 10, 2017.

The Public Staff has recommended that an Order be issued appointing a new emergency operator, requiring audit of the current emergency operator, and approving provisional rates subject to refund and true-up.

FINDINGS OF FACT

1. The Grande Oaks Subdivision with 14 residences on the wastewater utility system, is located off Bivens Road in northern Durham County, North Carolina, was developed in 1986 by Sedgefield Development Corporation (Sedgefield). The water system was conveyed to Heater Utilities, Inc., which is now Aqua North Carolina, Inc. (Aqua). The wastewater system consists of a collection system, a small package wastewater treatment plant, and an effluent discharge line with discharge to Crooked Creek. The discharge of the wastewater effluent was authorized by NPDES permit number NC0056731, which has expired. This wastewater system was permitted by the Division of Water Resources of the Department of Environmental Quality (DWR) to Sedgefield.

2. Sedgefield was administratively dissolved on November 17, 1993, by the North Carolina Secretary of State for failure to file annual reports.

3. On June 10, 1993, the Public Staff filed a motion in this docket requesting the Commission to issue emergency authority pursuant to G.S. 62-116(b) to Crosby Water and Sewer, Inc. (Crosby), to operate the wastewater collection and treatment system at the Grande Oaks Subdivision in Durham County. The Public Staff further moved that Sedgefield, the developer of Grande Oaks Subdivision, be ordered to appear before the Commission and show cause, if any there be, why it should not be found to have been furnishing wastewater utility service for

compensation in the Grande Oaks Subdivision without authority from this Commission in violation of G.S. 62-110, and to have abandoned such service without the prior consent of the Commission in violation of G.S. 62-118.

4. On June 11, 1993, the Commission entered an Order in this docket declaring that a real emergency exists with respect to the wastewater system owned and operated by Sedgefield in the Grande Oaks Subdivision as an emergency is defined in G.S. 62-116(b). The Commission also appointed Crosby to serve as emergency operator.

5. The Commission in its Order dated August 26, 1993, in this docket made findings of fact including:

...

> 2. Sedgefield has demanded and accepted compensation from residents of Grande Oaks Subdivision for sewer utility service.
> 3. Sedgefield Development Company is a public utility subject to the jurisdiction of the North Carolina Utilities Commission.
> 4. Sedgefield has never applied for a certificate of public convenience and necessity to provide sewer utility service in Grande Oaks Subdivision.
>
> ...
>
> 7. Sedgefield stopped paying operating costs and power to the sewer system was cut off in April 1993.
> 8. The Division of Environmental Management took over operation of the sewer system in April 1993 using emergency funds which were to expire on June 16, 1993.
> 9. Prior to the Commission's appointment of an emergency operator in its June 11, 1993, Order, a real and pressing emergency existed that sewer service could be interrupted to Grande Oaks customers.

6. The Commission in its August 26, 1993 Order concluded Sedgefield has furnished wastewater utility service for compensation in Grande Oaks Subdivision without authority from this Commission in violation of G.S. 62-110 and has abandoned such service without the prior consent of the Commission in violation of G.S. 62-118. Sedgefield agreed to the appointment of an emergency operator under the control of the Commission to operate the system. The Commission issued to Sedgefield a certificate of public convenience and necessity to provide wastewater utility service to 14 properties in Grande Oaks Subdivision.

7. On October 28, 1997, Crosby filed a letter with the Commission stating Crosby was negotiating with Envirolink, Inc. (Envirolink), to sell Crosby's assets related to the operation of wastewater facilities. By Order dated March 30, 1998, in Docket No. W-1036, Sub 0, Envirolink was appointed emergency operator for the Grande Oaks wastewater system.

8. By letter filed on June 8, 1998, Envirolink requested to be discharged as emergency operator and requested that John Poteat be appointed as emergency operator. By Order dated July 22, 1998, in Docket No. W-1036, Sub 0, the Commission appointed John Poteat d/b/a Enviroment Plus (Poteat) as the emergency operator for the Grande Oaks wastewater utility system.

WATER AND SEWER – EMERGENCY OPERATOR

9. By letter filed on November 8, 2001, in Docket No. W-1036, Sub 0, jointly signed by Poteat and Harden, Poteat requested to be discharged and Harden requested to be appointed emergency operator of the Grande Oaks wastewater utility system and the monthly flat rates be increased to $112 per residence. By Order dated December 18, 2001, in Docket No. W-1036, Sub 0, the Commission appointed Harden as emergency operator and approved the $112 per month flat rate.

10. On May 9, 2007, a Notice of Violation from the Division of Water Quality of the North Carolina Department of Environmental Quality (DWQ) was delivered to Jerry Tweed, Utilities Engineer, Public Staff Water Division, and filed in this docket on that same date for the Grande Oaks wastewater utility system stating:

a. the facilities NPDES Permit has been expired since January 31, 2003;
b. the discharge of wastewater from the Grande Oaks wastewater treatment facility to waters of the State without a NPDES Permit is a violation of G.S. 143-215.1(a)(1);
c. the responsible charge of this facility must submit an NPDES application; and
d. seven other necessary renovations.

11. On July 8, 2010, DWQ sent a Compliance Evaluation Inspection, filed in this docket on July 22, 2010, to Jerry Tweed for the Grande Oaks wastewater utility system, stating there still was not a NPDES Permit and this wastewater system continued to violate G.S. 143-215.1(a)(1). This document also summarized the status of plans to interconnect the Grande Oaks wastewater collection system to the City of Durham wastewater system.

12. DWQ sent a Compliance Evaluation Inspection dated June 13, 2011, to Jerry Tweed, Public Staff, filed in this docket on July 11, 2011, updating the City of Durham's interconnection plans and summarizing the wastewater systems non-compliance including lack of a NPDES Permit.

13. Public Staff Utilities Engineer Jerry Tweed sent a letter to DWQ dated July 14, 2011, filed in this docket on July 14, 2011, providing some of the history of the wastewater system, and that neither the Public Staff, the Commission, nor the emergency operator are the permittee. Jerry Tweed encouraged the interconnection to the City of Durham wastewater system.

14. Jerry Tweed worked to obtain the interconnection with the City of Durham from 2005 until his retirement in 2013. The interconnection projected capital costs materially increased to comply with North Carolina Department of Transportation specifications. In 2017, David Furr, the Director of the Public Staff Water Division, has met with City of Durham officials on a number of occasions to encourage the interconnection. It is uncertain when, at what cost, and if, there will be an interconnection. At this time, there is not a City of Durham commitment for an interconnection. The Grande Oaks wastewater system continues to be operated without a permittee and without an NPDES permit.

15. There continues to exist an emergency situation in which there is an imminent danger of losing adequate wastewater utility service due to the abandonment of service by Sedgefield in the Grande Oaks Subdivision and the request to resign by emergency operator Harden, justifying the appointment of a new emergency operator in accordance with G.S. 62-116(b) and G.S. 62-118(b).

16. There are currently 14 customers receiving wastewater utility service in Grande Oaks Subdivision.

17. Old North State Water Company, LLC (ONSWC), has stated that it is willing to be appointed to serve as emergency operator of the wastewater utility system serving Grande Oaks Subdivision, at the $112 per month flat rate previously approved by the Commission.

18. The Public Staff recommended that, in the interest of maintaining adequate utility service, the Commission immediately appoint ONSWC as emergency operator and establish a provisional rate of $112 per month, subject to refund and true-up.

19. Harden has failed to file all the monthly reports as required by the Commission's December 18, 2001 Order appointing Harden as emergency operator.

20. The Public Staff recommended that an audit of Harden's records be performed prior to discharging him as emergency operator.

21. Aqua North Carolina, Inc. (Aqua), which provides water service to Grande Oaks, is now providing billing and collection services for the emergency operator.

EVIDENCE AND CONCLUSIONS

The evidence for these findings of fact is found in the Commission's records. These facts are uncontroverted. The Commission, therefore, concludes an emergency exists, that Old North State Water Company, LLC, should be appointed as the emergency operator of the Grande Oaks wastewater utility system at 12:01 a.m., July 6, 2017, that an audit of Harden's records as emergency operator should be performed, and that the Public Staff's recommended provisional rate should be approved subject to refund and true-up.

IT IS, THEREFORE, ORDERED as follows:

1. That Old North State Water Company, LLC, is appointed emergency operator for the wastewater utility system serving Grande Oaks Subdivision in Durham County, North Carolina, effective after 12:01 a.m. on July 6, 2017.

2. That ONSWC is authorized to charge a monthly provisional rate of $112 per customer, subject to refund and true up.

3. That the following provisions are adopted by this Order:

a. That Sedgefield, its officers, directors, and shareholders, if any, are hereby ordered to offer all reasonable assistance to the emergency operator. Sedgefield shall not dispose or divest itself of any wastewater utility property, real or personal, without the prior written consent of the Commission.

b. That ONSWC, as emergency operator, is authorized to obtain billing and collection services from Aqua. Aqua is authorized to provide billing and collection services to the emergency operator for Grande Oaks Subdivision.

c. That the emergency operator shall maintain full records of receipts and expenses and shall file with the Commission and the Public Staff, by the end of the subsequent month, a summary financial report on a quarterly basis. The first report shall be filed on or before October 31, 2017, for the quarter ending September 30, 2017.

d. That the emergency operator shall have charge of the daily operation of the wastewater system in Grande Oaks Subdivision, and the emergency operator's duties and responsibilities shall include, among others, the following:

(i) Operations, inspections, and testing of the wastewater system;
(ii) Billing of all customers and collection of bills;
(iii) Routine and emergency maintenance and repair;
(iv) System renovations and additions necessary to maintain adequate wastewater service;
(v) Quarterly accounting to the Utilities Commission and the Public Staff of all rates collected, expenses incurred, checks written, and all monies spent; and
(vi) Providing a telephone number to customers for routine and emergency calls and a mailing address.

e. That the emergency operator may contract with any person or corporation to carry out any of the duties necessary for operation, maintenance, repair and renovations of the wastewater system, but the emergency operator alone shall have the ultimate responsibility to see that such duties are carried out.

f. That the emergency operator, in the performance of its duty, shall be free to seek assistance from customers of the wastewater system, plumbers, engineers, attorneys, and such other persons as may be necessary for the performance of its duties and responsibilities.

g. That the emergency operator shall, when it becomes necessary in the performance of its duties, seek the assistance of the North Carolina Department of Environmental Quality (DEQ), the Commission, the Public Staff, and the Durham County Health Department.

h. That the emergency operator shall collect from the customers of the wastewater system such rates and assessments as may be approved by the Commission and shall be fully authorized to bill and collect said rates and assessments and to disburse such of those funds as may be necessary to provide safe, reliable, and adequate wastewater utility service to the customers. Any customer who fails to pay the bill(s) authorized by this paragraph shall be disconnected by the emergency operator as provided by the orders, rules and regulations of the Commission.

i. That the emergency operator shall be entitled to all available records relating to the wastewater system, and those records shall include, but not be limited to, a list of customer names, addresses, and billing records.

j. That the emergency operator shall keep records of all monies collected through the rates and assessments and all monies expended in the operation of the wastewater system. In order to protect the customers' investments in the wastewater system in the event the wastewater system should be sold or revert to Sedgefield, the emergency operator is required to keep a separate record of all monies and assessment collected from customers and expended on improving and upgrading the wastewater system, including, but not limited to, the installation of new plant, replacement plant, rebuilt equipment, and the cost of labor associated with those improvements whether performed by the emergency operator or a contractor hired by the emergency operator.

k. That the emergency operator shall pay only those liabilities incurred by the emergency operator on and after the date of the appointment of the emergency operator. Those liabilities shall be defined as the liabilities arising from the emergency operator's operation of the Grande Oaks wastewater system pursuant to Commission Order. The disbursements by the emergency operator shall be made from the separate account set up by the emergency operator. The emergency operator shall account for any funds advanced by it for the operations.

l. That Sedgefield , its officers, agents, servants, and employees, if any, shall not

(i) Interfere with the emergency operator's operation of the wastewater utility plant, including the pumps, easements, rights-of-way, treatment facilities, mains, collection lines, storage or holding facilities, meters, filters, taps, or effluent disposal lines;
(ii) Receive or attempt to collect any wastewater bill payments or monies for wastewater service provided by the emergency operator;
(iii) Alter, impair, or remove any of the wastewater utility plant.

m. That the appointment of an emergency operator shall continue until terminated by an Order of the Commission finding that the emergency has ended and that the emergency operator is no longer required pursuant to G.S. 62-118(b) to provide public wastewater utility service to the customers of the Grande Oaks wastewater system.

n. That the emergency operator may petition the Commission at any time to be discharged as the emergency operator herein: and the emergency operator, prior to its discharge, shall provide an acceptable accounting to the Commission of all monies collected and disbursed during its tenure as emergency operator, as well as the amounts due and owing the emergency operator at the time of its discharge for its services performed as emergency operator. The emergency operator upon filing a petition for discharge shall also mail a copy of said petition to the Durham County Health Department and DEQ.

o. That this docket shall remain open for further reports and motions, from the customers, the emergency operator, the Durham County Health Department, the DEQ, the Public Staff, and for further orders of the Commission.

4. That the Schedule of Rates, attached as Appendix B, is approved on a provisional basis, subject to adjustment and true-up upon review and approval of the actual costs of operating the wastewater system. Said Schedule of Rates shall become effective for service rendered on and after July 6, 2017, and is deemed to be filed with the Commission pursuant with G.S. 62-138.

5. That the following items of information be made available to ONSWC:

a. Customer information for each residence connected to the system, containing at a minimum, customer name, service address, billing address, and contact phone numbers (home and work).

b. Copy of latest electrical power bill for the wastewater treatment plant (needed for transfer of service).

c. Copy of latest water bill, if any, for the wastewater treatment plant (needed for transfer of service).

d. Copy of system plans and specifications with any noted discoveries or changes by current owner for the past 12 months.

e. Copies of all monitoring reports and evaluation completed by the emergency operator for the past 24 months.

6. That the Public Staff is hereby requested to conduct an accounting audit of the books and records maintained by Harden as emergency operator of the Grande Oaks wastewater system and file the results of its accounting investigation, including recommendations regarding how to treat outstanding debts or amounts, if any, claimed by Harden. Upon resolution, the Commission will issue a further order discharging Harden as emergency operator.

7. That Aqua North Carolina, Inc., is currently franchised to provide water utility service in Grande Oaks Subdivision and shall continue to be the billing agent for the emergency operator with Aqua compensated at the rate of $2 per customer per month. Aqua shall continue to forward any funds it receives for wastewater utility service to the emergency operator.

8. That copies of this Order shall be served on H.O. Chesson, Jr., the former President of Sedgefield, Shannon Becker, President of Aqua, and the Division of Water Quality of DEQ.

9. That the Notice to Customers, attached as Appendix A, shall be mailed with sufficient postage or hand delivered by ONSWC to all customers in the Grande Oaks Subdivision no later than 10 days after the date of this Order; and that ONSWC shall submit to the Commission the attached Certificate of Service properly signed and notarized not later than 15 days after the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of July, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-1036, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Unauthorized Abandonment of Wastewater	)	
Utility Service in Grande Oaks Subdivision,	)	NOTICE TO CUSTOMERS
Durham County, North Carolina, by Sedgefield	)	
Development Corporation	)	

NOTICE IS HERBY GIVEN that Thomas Harden, d/b/a LTH3 Environmental Associates (Harden), has requested to be discharged from its duties and responsibilities as emergency operator of the wastewater utility system serving Grande Oaks Subdivision in Durham County, North Carolina, effective at 12:01 a.m. on July 6, 2017. The Commission has issued an order in this docket regarding the appointment of a new emergency operator. The Commission ordered the following:

1. That Old North State Water Company, LLC, is appointed as the emergency operator of the wastewater utility system serving Grande Oaks Subdivision in Durham County, North Carolina, effective after 12:01 a.m. on July 6, 2017.

2. That Old North State Water Company, LLC, is authorized to charge a provisional monthly flat rate of $112.00 per customer, subject to refund and true up.

3. That the Public Staff is hereby requested to conduct an accounting audit of the books and records maintained by Harden as emergency operator of the Grande Oaks wastewater system and file the results of its accounting investigation, including recommendations regarding how to treat outstanding debts or amounts, if any, claimed by Harden.

This the 12th day of July, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX B

SCHEDULE OF RATES

for

SEDGEFIELD DEVELOPMENT CORPORATION
(Old North State Water Company, LLC, Emergency Operator)

for providing wastewater utility service in

GRANDE OAKS SUBDIVISION

Durham County, North Carolina

Flat Sewer Rate: (Residential Service)

$112 per month [1/] [2/]

Connection Charge:	Actual Cost
Reconnection Charges:	
If sewer service cut off by utility for good cause	$15.00
Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charges 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.

WATER AND SEWER – EMERGENCY OPERATOR

[1/] The $112 per month is a provisional rate subject to refund and true up.

[2/] The $112 per month flat rate includes $2 per month, retained by Aqua North Carolina, Inc., for billing and collection. Aqua North Carolina, Inc., provides water utility service in Grande Oaks Subdivision.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1036, on this the 12th day of July, 2017.

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-1036, Sub 0, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of __________________, 2017.

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-1036, Sub 0.

Witness my hand and notarial seal, this the ____ day of ______________, 2017.

____

Notary Public

____

Printed Name

(SEAL) My Commission Expires: ______________________________

Date

DOCKET NO. W-218, SUB 363A

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 G.S. 62-133.12	))))))	ORDER APPROVING WATER AND SEWER SYSTEM IMPROVEMENT CHARGES ON A PROVISIONAL BASIS AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On October 30, 2017, 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, 2018, pursuant to Commission Rules R7-39 and R10-26 (Application).

On December 4, 2017, the Public Staff filed a Notice of Public Staff's Plan to Present Comments and Recommendations at the Commission's December 18, 2017 Regular Staff Conference (Notice).

On December 18, 2017, the 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. In Aqua's last general rate case, Docket No. W-218, Sub 363 (Sub 363 Rate Case), the Commission approved in its Order dated May 2, 2014, Aqua's request to utilize a WSIC and SSIC mechanism pursuant to G.S. 62-133.12, concluding that the rate adjustment mechanisms are in the public interest, and establishing WSIC and SSIC procedures for Aqua.

3. The implementation of the WSIC and SSIC for Aqua was first approved 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.

4. Aqua's proposed increases/decreases to the WSIC and SSIC previously approved by the Commission on July 1, 2017, are as follows:

	Previously Approved WSIC/SSIC Percentage	Net Change To WSIC/SSIC Percentage	Cumulative WSIC/SSIC Percentage
Uniform water	4.87%	-0.10%	4.77%
Uniform sewer	3.33%	0.26%	3.59%
Fairways/Beau Rivage water	2.93%	1.34%	4.27%
Fairways/Beau Rivage sewer	3.88%	0.65%	4.53%
Brookwood/LaGrange water	5.31%	0.08%	5.39%

5. The WSIC/SSIC percentages above include the Experience Modification Factor (EMF) adjustments from the 2016 annual WSIC/SSIC revenue review. The three rate divisions impacted are Aqua Uniform Sewer – adjusted downward by -0.07% (due to overcollection in 2016), Fairways/Beau Rivage Sewer – adjusted upwards by 0.02% (due to undercollection in 2016) and Brookwood/LaGrange Water – adjusted upward by 0.09% (due to undercollection in 2016).

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	$1,558,018	$0	$1,558,018
Uniform sewer	$413,562	$56,293	$469,855
Fairways/Beau Rivage water	$27,204	$14,209	$41,413
Fairways/Beau Rivage sewer	$47,458	$9,301	$56,759
Brookwood/LaGrange water	$249,083	$0	$249,083

7. Aqua's additional WSIC/SSIC revenue requirement is comprised of the calculated WSIC/SSIC revenue requirement for the current review period plus updates to previously approved WSIC/SSIC revenue requirements which became effective on January 1, 2015, July 1, 2015, January 1, 2016, July 1, 2016, January 1, 2017, and July 1, 2017. The updates include a roll forward of accumulated depreciation and accumulated deferred income taxes, a reduction in the state corporate income tax rate from 4% to 3%, a decrease in the public utility regulatory fee from 0.148% to 0:14%, and an update of the projected (non-WSIC/SSIC) annual service revenue amounts to Aqua's 2017/2018 projection.

8. Aqua is proposing the above increases 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, 2017 through September 30, 2017:

Water main relocation	$176,398
Total WSIC plant additions	$176,398
Sewer main relocation	$177,300
Replace blowers and/or motors	$627,254
Total SSIC plant additions	$804,554

9. Pursuant to 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 363 Rate Case. The total cumulative WSIC/SSIC revenue requirement calculations for Aqua NC Water, Fairways/Beau Rivage Sewer and Brookwood/Lagrange Water has exceeded the maximum revenue cap for these entities, therefore the WSIC/SSIC surcharges for this proceeding are based on maximum allowed revenue requirement.

10. As stated by the Commission in its Order adopting Commission Rules R7-39 and R10-26, issued on June 6, 2014, 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 the Company'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, except for a portion of the Willow Creek aeration blower project discussed below, are eligible water and sewer system improvements as defined in G.S. 62-133.12(b), (c), and (d).

12. The Public Staff recommended and implemented the removal of a portion of SSIC aeration blower replacement project at Willow Creek in the amount of $1,987, from the calculation of Aqua NC Wastewater cumulative revenue requirement. This portion of the project are costs to fabricate, deliver, and install a new aluminum weir box at the sewer treatment plant. The Public Staff is of the opinion that the new weir box does not meet the definition of an "eligible sewer system improvement" as determined by G.S. 62.133.12(d). The weir box should be characterized on Aqua's books as a capital project not subject to SSIC recovery. Removal of these costs reduces Aqua NC Wastewater additional SSIC revenue for this proceeding by $191, but the cumulative SSIC surcharge percentage as proposed by Aqua is not affected by the adjustment recommended by the Public Staff.

13. Based on the above adjustment, the Public Staff recommended the following adjustments to the WSIC and SSIC revenue requirement proposed by Aqua:

	WSIC/SSIC Revenue Requirement Per Aqua	WSIC/SSIC Revenue Requirement Per Public Staff	Impact of Public Staff Adjustments	WSIC/SSIC Percentages per Public Staff
Uniform water	$1,558,018	$1,558,018	$0	4.77%
Uniform sewer	$469,855	$469,664	$(191)	3.59%
Fairways water	$ 41,413	$41,413	$0	4.27%
Fairways sewer	$56,759	$56,759	$0	4.53%
Brookwood water	$249,083	$249,083	$0	5.39%

14. Based on the Public Staff's investigation to date, the Public Staff recommended that the cumulative WSIC and SSIC percentages proposed by Aqua be implemented effective for service rendered on or after January 1, 2018, 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 its proposed increases/decreases in the WSIC and SSIC percentages effective for service rendered on and after January 1, 2018. 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-3 to Aqua's Schedule of Rates effective for service rendered on and after January 1, 2018, 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-3 is approved and is deemed filed with the Commission pursuant to G.S. 62-138.

3. That Aqua shall mail to each of its customers with the next regularly scheduled customer billing the Commission-approved customer notice.[1]

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of December, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

[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.

APPENDIX A-3

AQUA NORTH CAROLINA, INC.
WATER AND SEWER SYSTEM IMPROVEMENT CHARGES

WATER SYSTEM IMPROVEMENT CHARGE

All Aqua NC water systems except as noted below	4.77% [1/]
Water systems in Brookwood and LaGrange service areas	5.39% [1/]
Water systems in Fairways and Beau Rivage service areas	4.27% [1/]
Glennburn, Knollwood, and Wimbledon systems in Gaston County	None [2/]
Thornton Ridge/Timberlake system in Alamance County	None [3/]
Clear Meadow system in Mecklenburg County	None [3/]

SEWER SYSTEM IMPROVEMENT CHARGE

All Aqua NC sewer systems except as noted below	3.59% [4/]
Sewer systems in Fairways and Beau Rivage service areas	4.53% [4/]

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/ These water systems, which were acquired from Wayne M. Honeycutt in Docket No. W-218, Sub 385, are not included under Aqua's uniform rates and improvements made in these systems are not eligible for Water System Improvement Charge recovery.

3/ These water systems were acquired by Aqua subsequent to Aqua's last general rate case and are not included in Aqua's uniform rates.

4/ 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 363A on this the 18th day of December, 2017.

ATTACHMENT A
PAGE 1 OF 3

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 363A

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 G.S. 62-133.12	)))))	NOTICE TO CUSTOMERS IN BROOKWOOD / LAGRANGE SERVICE AREAS

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued an Order dated December 18, 2017, pursuant to G.S. 62-133.12 and Commission Rules R7-39 and R10-26, authorizing Aqua North Carolina, Inc. (Aqua), to increase the Water System Improvement Charge (WSIC) effective for service rendered on and after January 1, 2018, 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 G.S. 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. On October 31, 2014, Aqua filed for its first semiannual adjustment to the WSIC and SSIC charges to be effective January 1, 2015.

ATTACHMENT A
PAGE 2 OF 3

The Public Staff – North Carolina Utilities Commission (Public Staff) carefully reviewed Aqua's stated WSIC, including a review of invoices, materials lists, work orders, employee time sheets, and other accounting records. On December 4, 2017, the Public Staff filed a Notice of Public Staff's Plan to Present Comments and Recommendations at the Commission's December 18, 2017 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 increase in the WSIC charge for the Brookwood and LaGrange service areas, effective for service rendered on and after January 1, 2018:

	Previously Approved WSIC Percentage	Net Change To WSIC Percentage	Cumulative WSIC Percentage
WSIC	5.31%	0.08%	5.39%

G.S. 62-133.12(g) limits the WSIC cumulative system improvement charges to 5% of the total water service revenues approved by the Commission in Aqua's last general rate case. The 5% maximum equals $249,083 in annual water service revenues. The Commission has approved total WSIC annual revenues of $249,083. However, due to decreases in the number of customers and average consumption, a 5.39% WSIC charge (consisting of 5.30% plus an 0.09% adjustment related to an undercollection in 2016) is approved to achieve the maximum allowable annual water service revenues of $249,083, based upon the projected revenues during the 12-month period following implementation of this WSIC charge, as required by Commission Rule R7-39(h)(2).

The WSIC percentage of 5.39% will be applied to the water utility bill of each customer under Aqua's applicable service rates and charges.

The cumulative 5.39% WSIC percentage results in a $1.63 increase to the monthly average residential bill for a customer using the average of 5,817 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 G.S. 62-133.12, dated June 6, 2014, in Docket No. W-100, Sub 54, the Aqua NC WSIC/SSIC Application filed October 30, 2017, the December 4, 2017 Public Staff Notice, and the December 18, 2017 Commission Order in Docket No. W-218, Sub 363A, 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 363A).

ATTACHMENT A
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 18th day of December, 2017.

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 363A

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 Adjustments	)	FAIRWAYS AND BEAU RIVAGE
to Water and Sewer System Improvement	)	SERVICE AREAS
Charges pursuant to G.S. 62-133.12	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued an Order dated December 18, 2017, pursuant to G.S. 62-133.12 and Commission Rules R7-39 and R10-26, authorizing Aqua North Carolina, Inc. (Aqua), to increase the Water System Improvement Charge (WSIC) and Sewer System Improvement Charge (SSIC) effective for service rendered on and after January 1, 2018, 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 G.S. 62-133.12, for authority to implement a semiannual 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. On October 31, 2014, Aqua filed for its first semiannual adjustment to the WSIC and SSIC charges to be effective January 1, 2015.

ATTACHMENT B
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The Public Staff – North Carolina Utilities Commission (Public Staff) carefully reviewed Aqua's stated WSIC and SSIC improvements, including a review of invoices, materials lists, work orders, employee time sheets, and other accounting records. On December 4, 2017, the Public Staff filed a Notice of Public Staff's Plan to Present Comments and Recommendations at the Commission's December 18, 2017 Staff Conference (Notice).

Aqua made a WSIC and SSIC eligible infrastructure improvement in the Fairways/Beau Rivage service to relocate water and sewer mains due to NCDOT replacement of bridge over Lords Creek on SR1100.

Based on the application filed by Aqua and the Public Staff's Notice and recommendations, the Commission has approved the following increases in the WSIC and SSIC charges for the Fairways and Beau Rivage service areas, effective for service rendered on and after January 1, 2018:

	Previously Approved WSIC/SSIC Percentage	Net Change To WSIC/SSIC Percentage	Cumulative WSIC/SSIC Percentage
WSIC	2.93%	1.34%	4.27%
SSIC	3.88%	0.65%	4.53%

The WSIC percentage of 4.27% will be applied to the water utility bill of each customer, and the SSIC percentage of 4.53% will be applied to the sewer utility bill of each customer, under Aqua's applicable service rates and charges.

The 4.27% WSIC percentage results in a $0.82 increase to the monthly average residential bill for a customer using the average of 7,655 gallons per month. The 4.27% WSIC percentage also will apply to the monthly bills for the customers on water systems where Aqua purchases bulk water.

The cumulative SSIC percentage of 4.53% will be applied to the sewer utility bill of each customer under Aqua's applicable service rates and charges. The cumulative 4.53% SSIC percentage results in a $1.65 increase to the monthly residential customer flat rate sewer bill.

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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 G.S. 62-133.12, dated June 6, 2014, in Docket No. W-100, Sub 54, the Aqua NC WSIC/SSIC Application filed October 30, 2017, the December 4, 2017 Public Staff Notice, and the December 18, 2017 Commission Order in Docket No. W-218, Sub 363A, 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 363A).

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 18th day of December, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

ATTACHMENT C
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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 363A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	NOTICE TO CUSTOMERS
202 MacKenan Court, Cary, North Carolina	)	IN AQUA NORTH CAROLINA
27511, for Approval of Semiannual Adjustments	)	UNIFORM RATES SERVICE
to Water and Sewer System Improvement Charges	)	AREAS
pursuant to G.S. 62-133.12	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued an Order dated December 18, 2017, pursuant to G.S. 62-133.12 and Commission Rules R7-39 and R10-26, authorizing Aqua North Carolina, Inc. (Aqua), to increase the Water System Improvement Charge (WSIC) and Sewer System Improvement Charge (SSIC) effective for service rendered on and after January 1, 2018, in its service areas in North Carolina.

WATER AND SEWER – FILINGS DUE PER ORDER

By Order entered in Docket No. W-218, Sub 363, on May 2, 2014, the Commission approved Aqua's request, pursuant to G.S. 62-133.12, for authority to implement a semiannual 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. On October 31, 2014, Aqua filed for its first semiannual adjustment to the WSIC and SSIC charges to be effective January 1, 2015.

The Public Staff – North Carolina Utilities Commission (Public Staff) carefully reviewed Aqua's stated WSIC and SSIC improvements, including a review of invoices, materials lists, work orders, employee time sheets, and other accounting records. On December 4, 2017, the Public Staff filed a Notice of Public Staff's Plan to Present Comments and Recommendations at the Commission's December 18, 2017 Staff Conference (Notice).

ATTACHMENT C
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Aqua made SSIC eligible infrastructure improvements to replace motors, blower and other mechanical equipment at eight wastewater treatment plants.

Based on the application filed by Aqua and the Public Staff's Notice and recommendations, the Commission has approved the following increases in the WSIC and SSIC charges, effective for service rendered on and after January 1, 2018:

	Previously Approved WSIC/SSIC Percentage	Net Change To WSIC/SSIC Percentage	Cumulative WSIC/SSIC Percentage
WSIC	4.87%	-0.10%	4.77%
SSIC	3.33%	0.26%	3.59%

WATER AND SEWER – FILINGS DUE PER ORDER

The WSIC percentage of 4.77% will be applied to the water utility bill of each customer, and the SSIC percentage of 3.59% will be applied to the sewer utility bill of each customer, under Aqua's applicable service rates and charges.

The cumulative 4.77% WSIC percentage results in a $2.19 increase to the monthly average residential bill for a customer using the average of 5,170 gallons per month. The cumulative 4.77% WSIC percentage also will apply to the monthly bills for the customers on water systems where Aqua purchases bulk water.

The cumulative 3.59% SSIC percentage results in a $2.33 increase to the monthly residential flat rate sewer bill. The cumulative 3.59% SSIC percentage will also apply to the monthly metered bills for customers on sewer systems where Aqua purchases bulk sewer treatment.

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 G.S. 62-133.12, dated June 6, 2014, in Docket No. W-100, Sub 54, the Aqua NC WSIC/SSIC Application filed October 30, 2017, the December 4, 2017 Public Staff Notice, and the December 18, 2017 Commission Order in Docket No. W-218, Sub 363A, 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 363A).

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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 18th day of December, 2017.

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 Order Approving Water and Sewer System Improvement Charges on a Provisional Basis and Requiring Customer Notice issued by the North Carolina Utilities Commission in Docket No. W-218, Sub 363A, by the date specified in the Order.

This the _____ day of __________________, ______.

By: ______________________________
Signature

____
Name of Utility Company

The above named Applicant, ______________________________, personally appeared before me this day and, being first duly sworn, says that the Order Approving Water and Sewer System Improvement Charges on a Provisional Basis and Requiring Customer Notice was mailed or hand delivered to all affected customers, as required by the Commission Order dated _____________ in Docket No. W-218, Sub 363A.

Witness my hand and notarial seal, this the ____ day of ____________, ____.

____
Notary Public

____
Typed or Printed Name

(SEAL) My Commission Expires: ______________________________
Date

DOCKET NO. W-354, SUB 356

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Carolina Water Service, Inc. of North Carolina, 4944 Parkway Plaza Boulevard, Suite 375, Charlotte, North Carolina 28217, for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All of its Service Areas in North Carolina, Except Corolla Light and Monteray Shores Service Area and Elk River Development	)	ORDER APPROVING STIPULATIONS, GRANTING PARTIAL RATE INCREASE, AND REQUIRING CUSTOMER NOTICE

HEARD: Tuesday, July 25, 2017, at 7:00 p.m., in the Buncombe County Courthouse, Courtroom 1A, 60 Court Plaza, Asheville, North Carolina

Wednesday, July 26, 2017, at 7:00 p.m., in the Watauga County Courthouse, 842 W. King Street, Boone, North Carolina

Tuesday, August 1, 2017, at 7:00 p.m., in the Mecklenburg County Courthouse, Courtroom 6350, 832 East 4th Street, Charlotte, North Carolina

Tuesday, August 22, 2017, at 7:00 p.m., in the Craven County Courthouse, Courthouse Annex, Courtroom #4, 302 Broad Street, New Bern, North Carolina

Wednesday, August 23, 2017, at 7:00 p.m., in Courtroom #317, New Hanover County Courthouse, 316 Princess Street, Wilmington, North Carolina

Monday, August 28, 2017, at 7:00 p.m., and Wednesday, September 20, 2017, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; and Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson, Lyons Gray, and Daniel G. Clodfelter

APPEARANCES:

For Carolina Water Service, Inc. of North Carolina:

Jo Anne Sanford, Sanford Law Office, PLLC, P.O. 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:

Gina C. Holt and William E. Grantmyre, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

For Corolla Light Community Association, Inc.:

Dwight W. Allen, Brady W. Allen, and Britton H. Allen, The Allen Law Offices, PLLC, 1514 Glenwood Ave., Suite 200, Raleigh, North Carolina 27608

BY THE COMMISSION: On February 24, 2017, Carolina Water Service, Inc. of North Carolina (CWSNC or Company) filed a letter notifying the North Carolina Utilities Commission (Commission or NCUC) of its intent to file a general rate case as required by Commission Rule R1-17(a). On March 31, 2017, CWSNC filed an application for a general rate increase (the Application) seeking authority: (1) to increase and adjust its rates for water and sewer utility service in all of its service areas in North Carolina, except for the Company's Corolla Light/Monteray Shores (CLMS) and Elk River service areas; (2) to pass-through any increases in purchased bulk water rates, subject to sufficient proof by CWSNC of the increase, as well as any increased costs of wastewater treatment performed by third parties and billed to CWSNC; and (3) to increase certain other charges.

By Order issued April 26, 2017, the Commission declared the matter to be a general rate case pursuant to G.S. 62-137 and suspended the proposed new rates for up to 270 days pursuant to G.S. 62-134.

The intervention and participation by the Public Staff – North Carolina Utilities Commission (Public Staff) was made and recognized pursuant to G.S. 62-15(d) and Rule R1-19(e) of the Rules and Regulations of the Commission.

On May 23, 2017, the Corolla Light Community Association, Inc. (CLCA or Community Association) a customer of CWSNC, filed a petition to intervene, stating that it is the homeowners' association for the Corolla Light development; that its membership includes more than 450 residents in the development; that its members are provided wastewater treatment services by CWSNC; and that the Community Association and its members have an interest in the subject matter of these proceedings. On May 25, 2017, CLCA filed an amended petition to intervene. CLCA's petition to intervene was granted by Commission Order dated June 16, 2017.

On June 2, 2017, the Commission issued its Order Scheduling Hearings and Requiring Customer Notice, scheduling the application for public hearings in Asheville, Boone, Charlotte, New Bern, Wilmington, and Raleigh, North Carolina, and for evidentiary hearing in Raleigh, North Carolina; establishing the dates for filing testimony; and requiring notice to all affected customers of the proposed rate increase and hearings.

On June 19, 2017, CWSNC filed the Commission-required certificate of service indicating that the notices to customers were served in conformity with the Order Scheduling Hearings and Requiring Customer Notice.

Forty-two different witnesses testified at the six public hearings and at the evidentiary hearing. Twenty-one witnesses testified in Asheville on July 25, 2017: Michael Sanders, Carl Burkhart, Susan Kish, Phil Reitano, Jim Hemphill, Jack Zinselmeier, John Jennings, Allen Higgins, Jack Barton, Margaretta Lang, Warren Grafer, Donn Levine, Richard Adams, Vernon McMinn, James T. Cain, Dennis Shellenberger, Jerard Worster, Tom Haynes, Sean O'Meara, Chuck Van Rens, and Betty Jackson. One customer, Howell Sharpe, testified in Boone on July 26, 2017. At the Charlotte hearing, on August 1, 2017, four customers testified: William R. Colyer, Damian Michael Werner, Isaac Cochran, and Chanyne Cupil. Simon Lock and Tom Musser testified in New Bern on August 22, 2017, and in Wilmington on August 23, 2017, the following nine people testified: Frank (Frances) Carroll,[1] Randal Woodruff,[2] Diana Wooley, Edward Worrell, Danny Conner, Ferrell Drewry, Ernest Thomas Chance, Thomas Mathis, and Mandy Ware. The Raleigh public hearing was held on August 28, 2017, and the following four witnesses testified: Vincent P. Roy, William Glance, Judith Bassett, and Ben Farmer. On September 20, 2017, in Raleigh, at the start of the evidentiary hearing, public witnesses Bryan McCabe and Vincent P. Roy testified (Public witness Roy for the second time).

On July 13, 2017, William R. Colyer, in his capacity as Secretary of the Board of Directors of the Bradfield Farms Homeowners Association, filed a petition to intervene in this proceeding. On August 10, 2017, the Commission entered an Order Denying Petition to Intervene Without Prejudice which denied the petition because it had not been signed or verified by a licensed attorney as required by Commission Rule R1-5(d) and G.S. 84-2.1 et. seq.

On July 21, 2017, CWSNC filed a notice regarding its semiannual water system improvement charge/sewer system improvement charge (WSIC/SSIC) surcharge applications pursuant to G.S. 62-133.12 and Commission Rules R7-39 and R10-26. The purpose of this filing was to notify the Commission, the Public Staff, and other interested parties that CWSNC did not intend to file an application for semiannual adjustments of the Company's Commission-authorized WSIC/SSIC surcharge mechanisms on August 1, 2017, to become effective on October 1, 2017.

On August 7, 2017, CWSNC filed the direct testimony and exhibit of Company witness Richard Linneman, the Company's Financial Planning and Analysis Manager.

On August 7, 2017, the Public Staff and CWSNC filled a Stipulation (First Stipulation) regarding cost of capital and capital structure issues.

[1] Mr. Carroll spoke on behalf of himself and 28 other customers from Belvedere Plantation Subdivision who were present at the hearing and stood to indicate their collective endorsement of Mr. Carroll's comments.

[2] Public witness Woodruff, County Manager for Pender County, stated that he is not a customer of CWSNC. At the Wilmington hearing, he read into the record a letter dated July 24, 2017, from the Pender County Board of Commissioners concerning its constituents who reside in Belvedere Plantation Subdivision.

On August 29, 2017, CWSNC filed a report regarding customer concerns raised at the public hearings held in Asheville and Boone on July 25, 2017 and July 26, 2017, respectively.

On September 11, 2017, CWSNC filed a report regarding customer concerns raised at the public hearings held in Charlotte and New Bern on August 1, 2017 and August 22, 2017, respectively.

On September 18, 2017, CWSNC filed a report regarding customer concerns raised at the public hearings held in Wilmington and Raleigh on August 23, 2017 and August 28, 2017, respectively.

On August 30, 2017, the Public Staff filed a motion to extend the due date for the filing of Public Staff and Intervenor testimony in this docket to September 12, 2017, and for the filing of rebuttal testimony to September 15, 2017. The motion was granted by Commission Order dated September 1, 2017.

On September 12, 2017, the Public Staff filed a Second Motion for Extension. In the Second Motion, the Public Staff stated that the Public Staff and CWSNC had reached a settlement of all issues in dispute but needed additional time for the Company to provide information regarding final capital projects that the Company seeks to include in the rate case proceeding and to allow the Public Staff time to audit those projects. Further, the Public Staff stated that all parties consented to the requested extension. The Public Staff thereafter requested that the Commission approve an extension of time until September 19, 2017, for the Public Staff and CWSNC to file a stipulation and settlement agreement and supporting prefiled testimony in this docket. The motion was granted by Order dated September 14, 2017.

On September 19, 2017, the Public Staff and CWSNC filed a Joint Stipulation (Second Stipulation) in this docket (including Joint Stipulation Exhibits A – E), which set forth the terms and conditions of the settlement agreement among those parties. In addition, on September 19, 2017, the Public Staff also filed the testimony and exhibits of Public Staff witnesses Sonja R. Johnson, Staff Accountant, Accounting Division; Gina Y. Casselberry, Advanced Utilities Engineer, Water, Sewer, and Communications Division; Lindsay Quant, Utilities Engineer, Water, Sewer, and Communications Division; and Calvin C. Craig, III, Financial Analyst, Economic Research Division in support of the Stipulations.

On September 20, 2017, the evidentiary hearing was convened in Raleigh, North Carolina as scheduled. During the morning session of the evidentiary hearing, two public witnesses testified. In addition, the prefiled testimony and exhibits offered by CWSNC witness Linneman and Public Staff witnesses Casselberry, Quant, Johnson, and Craig were copied into the record as if given orally from the witness stand. The prefiled testimony and exhibit submitted by Company witness Linneman were admitted in evidence. The exhibits of the Public Staff witnesses were identified as marked. The following documents were admitted in evidence: CWSNC's Application, including attached exhibits and the confidential and public sections of NCUC Form W-1; the three reports filed by CWSNC related to customer testimony; the First Stipulation regarding cost of capital and capital structure issues (filed on August 7, 2017); and the Second Stipulation (filed on

September 19, 2017). The Commission then recessed the hearing in order to have additional time to review the record before proceeding.

The evidentiary hearing was reconvened at 3:00 p.m. on September 20, 2017, in Raleigh, North Carolina. The Commission addressed questions to Public Staff witnesses Johnson, Casselberry, Quant, and Craig and CWSNC witness Linneman regarding their prefiled testimony and exhibits, including the two Stipulations. In addition, CWSNC witness Bryce Mendenhall, the Company's Vice President of Operations, testified in response to questions from the Commission. Witness Mendenhall did not prefile any testimony. During the course of its questioning of the above-referenced witnesses, the Commission requested that both the Company and the Public Staff provide certain information as late-filed exhibits. At the conclusion of its questions, the Chairman adjourned the evidentiary hearing, but advised the parties that the Commission reserved the right to reconvene the hearing for further questions, should it find reason to do so, after reviewing the late-filed exhibits to be submitted by the parties.

On September 26, 2017 and September 29, 2017, CWSNC filed late-filed exhibits consisting of Affidavits signed by Richard A. Linneman and J. Bryce Mendenhall, respectively, which contained their responses to questions posed by Commissioners at the September 20, 2017 evidentiary hearing.

On September 29, 2017, the Public Staff filed the late-filed exhibits of witnesses Johnson and Casselberry. On October 2, 2017, the Public Staff filed the late-filed exhibits of witness Craig.

By Order dated October 13, 2017, the Commission, after considering the late-filed exhibits and the record proper, admitted the late-filed exhibits into evidence, formally adjourned the evidentiary hearing, and required the parties to the proceeding to file briefs and proposed orders in 10 days.

On October 23, 2017, CWSNC and the Public Staff filed a Joint Proposed Order.

On October 24, 2017, CLCA filed a letter with the Commission stating that CLCA does not object to the Stipulation between the Public Staff and CWSNC.

On the basis of the Application; the First Stipulation; the Second Stipulation; the public witness testimony; the testimony and exhibits of CWSNC witnesses Linneman and Mendenhall, including their late-filed Affidavits; the testimony and exhibits of Public Staff witnesses Johnson, Casselberry, Quant, and Craig, including their late-filed exhibits; and the entire record in this proceeding, the Commission is of the opinion that the provisions of the First and Second Stipulations are just and reasonable. Accordingly, the Commission makes the following

FINDINGS OF FACT

1. CWSNC 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.[1] CWSNC provides water and sewer utility service to customers in 38 counties in North Carolina. CWSNC is a wholly-owned subsidiary of Utilities, Inc.[2]

2. CWSNC is properly before the Commission pursuant to Chapter 62 of the General Statutes of North Carolina seeking a determination of the justness and reasonableness of its proposed rates and charges for its water and sewer utility operations.

3. As of the 12-month period ending December 31, 2016, CWSNC served 29,883 water customers and 20,020 sewer customers, including Elk River and CLMS; and 3,636 water and 1,224 sewer availability customers. CWSNC operates 92 water systems and 39 sewer systems in the State.

4. A total of 42 individuals[3], almost all of whom are customers, testified at the six public hearings and the evidentiary hearing, with approximately 20 of those witnesses expressing service-related concerns. Such concerns included repair and maintenance issues involving main breaks, road repairs, sewage spills or backups, water quality in terms of particulate and hardness issues, and customer communications issues, including comments regarding boil water notices and the sewage spills. In addition, most, if not all, of the customers who appeared as witnesses testified in opposition to the proposed rate increase.

5. CWSNC filed three reports with the Commission, verified by Company Vice President of Operations, J. Bryce Mendenhall, addressing the service-related concerns and other comments expressed by the public witnesses who testified at the public hearings. Such reports described each of the witnesses' specific service-related concerns and comments, the Company's response, and how each concern and comment was addressed, if applicable.

6. The overall quality of service provided by CWSNC is adequate.

[1] On April 22, 2016, CWSNC, Bradfield Farms Water Company (Bradfield Farms), Carolina Trace Utilities, Inc. (Carolina Trace), CWS Systems, Inc. (CWSS), Elk River Utilities, Inc. (Elk River), and Transylvania Utilities, Inc. (Transylvania) filed a Joint Application for Approval of Merger with the Commission in Docket No. W-354, Sub 350, et al., requesting approval of the merger of Bradfield Farms, Carolina Trace, CWSS, Elk River, and Transylvania (all of which, like CWSNC, were wholly-owned subsidiaries of Utilities, Inc.) into CWSNC. On August 17, 2016, the Commission entered an Order Approving Merger. The Articles of Merger were filed with the North Carolina Secretary of State on August 30, 2016. Since that date, CWSNC has owned and operated all of the merged water and sewer systems previously owned and operated by the five former Utilities, Inc. subsidiaries.

[2] Utilities, Inc. owns regulated utilities in 16 states which provide water and sewer utility service to approximately 197,750 customers.

[3] One customer testified twice in Raleigh; once at the public hearing held on August 28, 2017 and again at the start of the evidentiary hearing held on September 20, 2017.

WATER AND SEWER – RATE INCREASE

7. The test period for this rate case proceeding is the 12-month period ended December 31, 2016, adjusted for certain known and actual changes in plant, revenues, and costs based upon circumstances and events occurring or becoming known through September 13, 2017, prior to the close of the evidentiary hearing in this proceeding.

8. CWSNC's last general rate case (pre-merger) was decided by Order (2015 Rate Case Order) entered on December 7, 2015, in Docket No. W-354, Sub 344. Transylvania's last general rate case (pre-merger) was decided by Order entered on January 15, 2010, in Docket No. W-1012, Sub 12. Carolina Trace's last general rate case (pre-merger) was decided by Order entered on November 24, 2010, in Docket No. W-1013, Sub 9. Bradfield Farms' last general rate case (pre-merger) was decided by Order entered on March 27, 2015, in Docket No. W-1044, Sub 41. CWSS's last general rate case (pre-merger) was decided by Order entered on February 24, 2016, in Docket No. W-778, Sub 91. Elk River's last general rate case was decided by Order entered on September 20, 2016, in Docket No. W-1058, Sub 7.[1]

9. The present rates for water and sewer service in all CWSNC's service areas have been in effect since January 1, 2017, pursuant to the Commission's Order issued on December 20, 2016, in Docket Nos. M-100, Sub 138, M-100, Sub 142, and W-354, Sub 342.

10. On August 7, 2017, CWSNC and the Public Staff filed the First Stipulation regarding cost of capital and capital structure issues and on September 19, 2017, CWSNC and the Public Staff filed the Second Stipulation regarding all remaining terms and conditions. The First and Second Stipulations settled all issues between CWSNC and the Public Staff.

11. By its Application, CWSNC initially requested a total annual revenue increase in its water and sewer rates of $5,557,499, a 19.14% increase over the total revenue level generated by the rates currently in effect for the Company.

12. It is reasonable and appropriate to design and approve rates in this proceeding based upon CWSNC's proposal, agreed to by the Public Staff, to establish the following four Rate Divisions:

CWSNC Uniform Water
CWSNC Uniform Sewer
Bradfield Farms/Fairfield Harbour (BF/FH) Water
Bradfield Farms/Fairfield Harbour (BF/FH) Sewer

13. CWSNC's present and proposed service revenues for the 12-month period ending December 31, 2016, including pro forma adjustments, are shown below:

[1] The Order in the Elk River rate case was issued after consummation of the merger.

WATER AND SEWER – RATE INCREASE

	Present	Proposed
CWSNC Uniform Water Operations	$15,122,929	$18,414,144
CWSNC Uniform Sewer Operations	$11,755,741	$13,294,803
BF/FH Water Operations	$ 717,509	$ 1,029,392
BF/FH Sewer Operations	$ 1,370,666	$ 1,792,244

14. CWSNC's total original cost rate base used and useful in providing service to its customers is $98,278,591 for its combined operations, consisting of $51,860,184 for CWSNC Uniform Water Operations; $39,028,369 for CWSNC Uniform Sewer Operations; $1,830,765 for BF/FH Water Operations; and $5,559,273 for BF/FH Sewer Operations.

15. Accumulated depreciation consists of the following balances for water and sewer operations:

CWSNC Uniform Water Operations	$26,418,797
CWSNC Uniform Sewer Operations	$19,466,724
BF/FH Water Operations	$ 1,741,151
BF/FH Sewer Operations	$ 2,996,036

16. Contributions in aid of construction (CIAC), reduced by accumulated amortization of CIAC, consist of the following amounts for water and sewer operations:

CWSNC Uniform Water Operations	$18,763,662
CWSNC Uniform Sewer Operations	$18,798,350
BF/FH Water Operations	$ 1,131,010
BF/FH Sewer Operations	$ 4,341,809

17. The levels of total operating revenues under present rates appropriate for use in this proceeding are $15,202,586 for CWSNC Uniform Water operations; $11,810,369 for CWSNC Uniform Sewer operations; $748,466 for BF/FH Water operations; and $1,371,245 for BF/FH Sewer operations, for a total level of operating revenues for combined operations of $29,132,666.

18. The overall levels of total operating expenses under present rates appropriate for use in this proceeding are $12,597,944 for CWSNC Uniform Water operations; $9,306,364 for CWSNC Uniform Sewer operations; $752,840 for BF/FH Water operations; and $1,165,407 for BF/FH Sewer operations, for a total level of operating expenses under present rates for combined operations of $23,822,555.

19. It is reasonable and appropriate for CWSNC to recover total rate case expenses of $710,275, consisting of $424,336 related to the current proceeding and $285,939 of unamortized rate case expense from prior proceedings, to be amortized and collected over a three-year period, for an annual level of rate case expense of $236,758.

20. It is reasonable and appropriate that the unamortized balance of the gain on sale of systems sold to Charlotte Mecklenburg Utility Department as of December 31, 2017, should be amortized over a three-year period.

21. The testimony of Public Staff witness Craig, regarding the reasonableness of the stipulated capital structure, cost of debt, and return on equity component of the overall rate of return, adequately supports the capital structure consisting of 48.00% long-term debt and 52.00% common equity, the embedded cost of long-term debt of 5.93% and the return on common equity of 9.60% agreed to by CWSNC and the Public Staff in the First and Second Stipulations. The stipulated capital structure and debt and equity returns are just and reasonable and appropriate for use in setting rates in this proceeding. Accordingly, the just, reasonable, and appropriate components of the rate of return for CWSNC are as follows:

a. Long-Term Debt Ratio	48.00%
b. Common Equity Ratio	52.00%
c. Embedded Cost of Debt	5.93%
d. Return on Common Equity	9.60%
e. Overall Weighted Rate of Return	7.84%

22. It is reasonable and appropriate to determine the revenue requirement for CWSNC using the rate base method as allowed by G.S. 62-133.

23. It is reasonable and appropriate to use the current statutory regulatory fee rate of 0.14% to calculate CWSNC's revenue requirement.

24. It is reasonable and appropriate to use the current State corporate income tax rate of 3% and the applicable federal income tax rates to calculate CWSNC's revenue requirement.

25. CWSNC's right to charge a WSIC and SSIC was initially granted by the Commission in Docket No. W-354, Sub 336 by Order issued March 10, 2014. All of CWSNC's post-merger customers are subject to the application in this general rate case. Therefore, the Company's Commission-authorized WSIC/SSIC Mechanisms will, on a going-forward basis, apply to all customers served by CWSNC, including those customers incorporated into the Company as a result of the Commission-authorized 2016 corporate merger.

26. Pursuant to Commission Rules R7-39(k) and R10-26(k), the WSIC and SSIC presently in effect are reset at zero as of the effective date of this Order.

27. The Ongoing Three-Year Plan filed by CWSNC as Appendix C to the Rate Case Application on March 31, 2017, is reasonable and meets the requirements of Commission Rules R7-39(m) pertaining to WSIC and R10-26(m) pertaining to SSIC.

28. The agreed-upon rates will provide CWSNC with an increase in its annual level of authorized service revenues through rates and charges approved in this case by $3,759,480, a 12.98% increase, consisting of an increase for CWSNC Uniform Water Operations of $2,292,099, an increase for CWSNC Uniform Sewer Operations of $871,485, an increase for BF/FH Water

Operations of $233,246, an increase for BF/FH Sewer Operations of $362,650, and no change in revenues for the CLMS and Elk River service areas. After giving effect to these authorized increases in water and sewer revenues, the total annual operating revenues for the Company will be $32,876,357, consisting of the following levels of just and reasonable operating revenues:

CWSNC Uniform Water Operations	$17,486,892
CWSNC Uniform Sewer Operations	$12,678,804
BF/FH Water Operations	$ 979,776
BF/FH Sewer Operations	$ 1,730,885

29. CWSNC's pump-and-haul expenses and the new spray charges are not a part of Belvedere's system modification project, but are a result of an extraordinary expense and should continue to be amortized for a 10-year amortization period with no unamortized balance included in rate base. It is reasonable and appropriate that only invoiced costs and not capitalized time or interest during construction be included. There will be no additional pump-and-haul expenses added to the current Belvedere system deferred balance in future proceedings before the Commission.

30. In this proceeding, it is reasonable and appropriate for the current, system-specific sewer rates for the CLMS service area to remain unchanged from those established in Docket Nos. W-354, Subs 327, 336, and 344 and for CWSNC's remaining CLMS revenue sewer requirement to be recovered through its Uniform Sewer Rates for other service areas, as stipulated. In future general rate case proceedings, the issue of rate disparity should be reviewed again by CWSNC, the Public Staff, and any other interested party and appropriate consideration should be given to moving the CLMS service area toward uniform rates in light of the facts and circumstances that exist at that time.

31. In this proceeding, it is reasonable and appropriate for the current, system-specific water and sewer rates for CWSNC's Elk River service area to remain unchanged and for the Company's remaining Elk River water and sewer revenue requirement to be recovered through its Uniform Water and Sewer Rates for other service areas, as stipulated. Elk River's last general rate case was decided by Order entered on September 20, 2016, in Docket No. W-1058, Sub 7.

32. It is reasonable and appropriate for CWSNC to increase the Company's "new sewer customer charge" from $21.95 to $27.00; increase the meter testing fee from $19.95 to $20.00; increase the "new water customer charge" from $26.93 to $27.00; increase the reconnection charge from $26.93 to $27.00; and increase the charge for processing checks returned by the bank due to insufficient funds from $24.94 to $25.00. Under the Second Stipulation, these present charges were not increased or changed for the CLMS and Elk River customers.

33. The Schedules of Rates (attached hereto as Appendices A-1, A-2, A-3, and A-4) for CWSNC water and sewer utility service and the Schedules of Connection Fees for CWSNC Uniform Water and Uniform Sewer (attached hereto as Appendices B-1 and B-2), agreed to by CWSNC and the Public Staff, are just and reasonable and should be approved.

WATER AND SEWER – RATE INCREASE

34. The following chart shows the average monthly customer bills at the Company's present and proposed rates, including percentage increases and decreases, compared to the Commission-approved rates in this proceeding:

WATER OPERATIONS

Service Area	CWSNC Present	CWSNC Proposed	Percent Increase (Decrease)	Commission Approved	Percent Increase (Decrease)
Uniform Flat	$41.60	$50.17	20.60%	$47.45	14.06%
Uniform Metered	$47.87	$57.60	20.33%	$55.09	15.08%
Clearwater	$34.18	$57.60	68.52%	$55.09	61.18%
Treasure Cove	$22.06	$57.60	161.11%	$24.81	12.47%
Forest Hill	$43.25	$57.60	33.18%	$55.09	27.38%
Fairfield Mountain	$47.49	$57.60	21.29%	$55.09	16.00%
Sapphire Valley	$56.39	$57.60	2.15%	$55.09	(2.31)%
Connestee Falls	$53.88	$57.60	6.90%	$55.09	2.25%
Carolina Trace	$34.19	$35.75	4.56%	$33.24	(2.78)%
Carolina Forest	$35.10	$39.65	12.96%	$37.14	5.81%
High Vista Estates	$35.34	$39.89	12.87%	$37.38	5.77%
Riverpointe	$47.47	$52.02	9.59%	$49.51	4.30%
Whispering Pines	$31.28	$35.83	14.55%	$33.32	6.52%
White Oak/Lee F.	$35.34	$39.89	12.87%	$33.51	(5.18)%
Winston Plantation	$35.34	$39.89	12.87%	$33.51	(5.18)%
Winston Pointe	$35.34	$39.89	12.87%	$33.51	(5.18)%
Woodrun	$35.10	$39.65	12.96%	$37.14	5.81%
Yorktown	$42.34	$46.89	10.75%	$44.38	4.82%
Zemosa Acres	$43.37	$47.92	10.49%	$45.41	4.70%
Fairfield Harbour	$20.44	$26.97	31.95%	$24.81	21.38%
Bradfield Farms	$16.05	$26.97	68.04%	$24.81	54.58%

Average bill calculated using the average consumption of 3,980 gallons, based on all residential customers with 5/8-inch meter.

SEWER OPERATIONS

Service Area	CWSNC Present	CWSNC Proposed	Percent Increase (Decrease)	Commission Approved	Percent Increase (Decrease)
Uniform Flat	$52.55	$60.22	14.60%	$56.57	7.65%
Sapphire Valley	$35.52	$60.22	69.54%	$56.57	59.26%
Nags Head	$62.65	$60.22	(3.88)%	$56.57	(9.70)%
Connestee Falls	$49.92	$59.93	20.05%	$56.60	13.38%
Uniform Rate	$52.31	$59.93	14.57%	$56.60	8.20%
White Oak Plt	$49.47	$54.42	10.01%	$53.22	7.58%
Lee Forest	$49.47	$54.42	10.01%	$53.22	7.58%
Winston Pt.	$49.47	$54.42	10.01%	$53.22	7.58%
Kings Grant	$46.90	$51.85	10.55%	$49.73	6.03%
College Park	$53.40	$58.35	9.27%	$56.23	5.30%
Mt. Carmel	$54.19	$65.73	21.30%	$63.61	17.38%
Fairfield Mountain	$86.67	$108.37	25.04%	$106.25	22.59%
Carolina Trace	$64.04	$59.93	(6.42)%	$56.60	(11.62)%
Fairfield Harbour	$37.89	$42.83	13.04%	$41.40	9.26%
Bradfield Farms	$26.56	$42.83	61.26%	$41.40	55.87%
Bulk Sewer	$25.20	$41.83	65.99%	$40.40	60.32%

Average bill calculated using the average consumption of 3,417 gallons, based on all residential customers with 5/8-inch meter.

35. The First and Second Stipulations contain the provision that the Stipulating Parties agree that none of the positions, treatments, figures, or other matters reflected in the agreements should have any precedential value, nor should they otherwise be used in any subsequent proceedings before this Commission or any other regulatory body as proof of the matters in issue.

36. The First and Second Stipulations contain the provision that the agreements made therein do not bind the Stipulating Parties to the same positions in future proceedings, and the parties reserve the right to take different positions in any future proceedings. The Second Stipulation also contains the provision that no portion of the Second Stipulation is binding on the Stipulating Parties unless the entire Second Stipulation is accepted by the Commission.

DISCUSSION AND CONCLUSIONS

The evidence for the following conclusions is contained in the Application; in the First Stipulation; in the Second Stipulation; in the testimony of the public witnesses; in CWSNC's Report on Customer Comments From Public Hearings in Asheville and Boone, North Carolina, filed on August 29, 2017; in CWSNC's Report on Customer Comments From Public Hearings in Charlotte and New Bern, North Carolina, filed on September 11, 2017; in CWSNC's Report on Customer Comments From Public Hearings in Wilmington and Raleigh, North Carolina, filed on September 18, 2017; in the testimony, affidavits, and exhibits of CWSNC witnesses Linneman and Mendenhall; in the testimony and exhibits of Public Staff witnesses Johnson, Casselberry, Quant, and Craig; and in the entire record in this proceeding.

I. Public Hearings and Service Quality

Six public hearings were held across the State for the benefit of public witnesses. Public witnesses were also given the opportunity to be heard at the evidentiary hearing which was held in Raleigh, North Carolina. Forty-two different public witnesses testified during those seven hearings; with approximately 20 of those public witnesses expressing service-related concerns.

In response to the customers' complaints, CWSNC filed three reports with the Commission, verified by Company Vice President of Operations, J. Bryce Mendenhall (collectively referenced as "Reports on Customer Concerns"), addressing the service-related and other concerns expressed by the public witnesses who testified at the six public hearings held in this docket. Such reports described each of the witnesses' specific service-related and other concerns, the Company's response, and how each concern was addressed, if applicable. The three reports are summarized as follows:

(1) Asheville (July 25, 2017)

Twenty-one witnesses testified at the Asheville public hearing. Each customer who testified expressed concern about the proposed percentage increase in rates. Several of the customers made positive comments about the level of service provided by CWSNC, the professionalism of Company personnel, and/or the quality of the water. However, customers variously raised issues about the level of service (including repairs), water quality, communications, and rate equity among different kinds of service providers.

The service quality issues were principally confined to three areas: (1) water main breaks; (2) delays in road-bed repairs; and (3) communications—including those relating to boil water notices, a sewage spill, and the rate increase. Other areas of customer focus included: the differential between reported "average" statewide rates for water and wastewater and the "average" for CWSNC; the move towards uniform rates; and the statutory standards that govern the Company's ability to recover in rates the increased investment in plant and costs of operation.

In its Asheville report, CWSNC offered specific responses to the customer service complaints which were voiced at the public hearing. For instance, the following service quality concerns expressed by public witnesses Michael Sanders, Jack Zinselmeier, and Margaretta Lang and the Company's responses to these concerns were contained in the Company's report filed on August 29, 2017 regarding the Asheville public hearing.

Public witness Michael Sanders expressed concern about the frequency of pipe failures and main breaks at Connestee Falls, the Company's response to a recent sewage spill into the lake, and communications about boil water notices. The Company offered the following response to witness Sanders' testimony:

> Investment. CWSNC has spent an estimated $489,000 since 2009 on various water and sewer capital projects within the Connestee Falls subdivision. Much of the

investment replaced approximately 2,040 feet of water main along Nodatsi Drive and approximately 5,000 feet of sewer force main along the lakes within Connestee Falls. Additional radiological treatment was added to a well system and permitting plans are underway to replace the aging wastewater treatment plant, which is expected to be a significant capital project (since 2015, $236,000 has been invested in engineering costs associated with the plant).

Main and Service Line Breaks. Since January, 2016, CWSNC has experienced approximately (13) service interruptions in Connestee Falls, one of which was due to ordinary maintenance. Water main breaks are inevitable for various reasons, including aged infrastructure and a failure, upon initial installation by a developer, to properly bed the pipe. Both the Company and customers are dependent upon the integrity of the initial installations, which were generally not performed by CWSNC. CWSNC apologizes for these service interruptions and assures its customers and the Commission that the Company has taken, and will continue to take, all reasonable and necessary steps to address and satisfactorily resolve all service-related problems, including the breaks, as expeditiously and efficiently as possible. Specifically, the Company is tracking line breaks and has a replacement plan in place to address the vulnerable sections of the existing water main. In all of these instances, boil water notices were issued by use of the automated "Voice Reach" system, which delivers a voice message to the customer. Two of those main breaks occurred back-to-back, so, in those cases, only the initial advisory was issued and rescinded. In two others, the customers' doors were tagged by CWSNC personnel, since the breaks only affected a small number of customers.

Unintended Sewage Spill into Lake Atagahi. CWSNC recently experienced two "sanitary sewer overflows" ("SSOs"), which were on June 15, 2017, and July 7, 2017. These SSOs were due to lightning strikes at the lift station and resulted in Lake Atagahi being closed for recreation purposes from Friday, June 16, 2017, to Tuesday, June 20, 2017. CWSNC pulled samples and tested the water on Friday, June 16, 2017, at which time the coliform levels were elevated. The [Connestee Falls POA] tested the water on Monday, June 19, 2017, and determined that the levels were acceptable, thus allowing Lake Atagahi to re-open the next day. The SSOs were also reported to the North Carolina Department of Environmental Quality ("DEQ"), as required.

Complaint about Having to Pay for Testing. As indicated above, CWSNC sampled Lake Atagahi at its expense. The Company also understands that the CFPOA samples and tests Lake Atagahi water on a weekly basis to monitor its suitability for recreation purposes. Thus, the Company is unclear why the CFPOA would have necessarily experienced increased costs due to the SSO incident, under the circumstances described, but apologizes if that was the case. The Company is willing in good faith to reimburse the CFPOA for the cost of this test and will contact the CFPOA representative to discuss such payment.

Poor Communication About Boil Water Notices. *Attachment 1 (omitted in this Order)* is an example of the boil water advisories that were issued by CWSNC to

> Connestee Falls customers in conjunction with each line break. It should be reiterated that only the customers affected by a break are notified. The boil water advisories state the specific streets (i.e., customers) that were affected. These notices are delivered by the Voice Reach system, after any break that necessitates the alert. On a going-forward basis, CWSNC will request that customers provide the Company with their best telephone and e-mail contact information, to assist in the event of future boil water advisories. Receipt of proper customer contact information facilitates proper and prompt delivery of the required customer communication.

Jack Zinselmeier complained of delayed responses to road bed repairs, on two separate instances. CWSNC offered the following statements in its Asheville Report in response to witness Zinselmeier's testimony:

> CWSNC experienced a water main break in November 2016 that occurred from a sudden hydrant closing by the fire department while it battled a wildfire in the community. A road repair was necessitated by that break and delays in repair were caused by multiple factors. First, the resort was actually evacuated on November 11, 2016, due to the wildfire. Second, the asphalt plant was closed from December 5 through December 23, 2016, because of cold weather. The road repair was made on December 26, 2016, three days after the plant reopened.
>
> On April 27, 2017, there was another road repair event, at 197 O'Brien Road. A water main leak occurred and was repaired the same day. However, the asphalt company experienced a scheduling delay in getting the road patched, which pushed road repair completion to June 12, 2017.

In her testimony, Margaretta Lang complained of boil water notices, and of the breaks that led to them. CWSNC responded to witness Lang's testimony as follows:

> CWSNC experienced one water main break in 2017 which resulted in a boil water advisory that would have affected Ms. Lang. The break, which occurred on July 13, 2017, was repaired on the same day; both the boil water and rescind notices are appended as *Attachment 3 (omitted from this Order).*

(2) Boone (July 26, 2017)

One customer testified in Boone. Howell Sharpe, Sugar Mountain subdivision, had no complaints with the water service being provided by CWSNC. He did, however, express concern about the amount and frequency of the Company's rate increases, comparing them unfavorably to his experience in Atlanta.

The Company responded to witness Sharpe's rate increase concerns in its general responses to customer issues section of its report filed on August 29, 2017.

(3) Charlotte (August 1, 2017)

A total of four witnesses testified at the Charlotte public hearing. All four witnesses reside in CWSNC's Bradfield Farms service area. Those four witnesses—William R. Colyer, Damian Michael Werner, Isaac Cochran, and Chanyne Cupil—testified primarily in opposition to the magnitude and impact of the proposed rate increase.

The witnesses generally voiced no current or ongoing service quality complaints which personally affect their respective utility service. Regarding the Company's quality of service, witness Colyer testified that:

> ...the folks from Utilities, Inc....have continued to provide an excellent level of service to Bradfield Farms...I mean, they're in my speed dial, and if there's a problem they are quick to respond, and we do appreciate that.

Regarding service quality, witness Cupil testified that she and her husband experienced one service-related problem in the eight years that they have been living in the community. The problem was related to a sewage backup which, although unpleasant, was resolved by the Company.

Witness Werner, who, when asked whether he had experienced any service-related problems, replied:

> I have not, but I know that we have had some issues lately with sewage backing up and so forth. Those were not affecting my house, but I've heard about it throughout the neighborhood. But, no, my service has been good. And I do -- like I said, I mean, my interactions with the Company have been okay, but I just can't see the justification for that kind of an increase.

In its post-hearing report, the Company responded to witness Werner's testimony as follows (in part):

> CWSNC has searched its records regarding sewage backups which occurred close in time to witness Werner's testimony on August 1, 2017. The closest event in point of time occurred on June 2, 2017, at 7:30 a.m. at 7221 Maitland Court. This sewage backup caused flooding in the home at that address. Upon investigation, Company personnel found a backup at Maitland Court and Jardin Way. This event was caused by asphalt, rocks, and brick which were found in the manhole. A contractor (not affiliated with the Company) had repaved streets in the neighborhood prior to this backup. CWSNC contacted its insurance company and directed the insurer to take care of the affected customer; ensure that any damage to the customer's property was corrected; and then seek recompense from the contractor. Follow-up conversations with the affected homeowner indicated that all issues had been satisfactorily resolved. The Company's insurance carrier is now seeking damages against the contractor. There have been no further complaints from the affected customer.

> Company records indicate that there were no other backup events during 2017, which occurred at Bradfield Farms prior to the August 1, 2017 public hearing. During 2016, there was one event which occurred on May 25, 2016. Company personnel cleaned the main and found lots of "wipes" which caused this blockage. The blockage caused a sanitary sewer overflow of approximately 600 gallons which did not reach any surface waters, just a dry ditch. The overflow did not impact any homes.
>
> *******
>
> To evaluate the integrity of the Bradfield Farms sewage collection system so as to minimize the chances for future backup problems, CWSNC contracted with a company (RedZone) to initiate a project which consists of using robotics technology to internally examine the integrity of the Company's sewer collection pipe systems. The Bradfield Farms project, which began on September 6, 2017, will examine the integrity of the entire sewage collection system. The outcome of the project allows CWSNC to identify specific points in the sewage collection system which are in need of repair, rather than the Company having to undertake an unnecessary and expensive whole-system replacement. In particular, the project concentrates on pipe integrity, possible pipe damage, root intrusion, potential or actual blockages, and identifying sources of inflow and infiltration ("I&I").

(4) New Bern (August 22, 2017)

Two customer witnesses testified at the New Bern public hearing. Both witnesses reside in CWSNC's Fairfield Harbour service area. Those two witnesses—Simon Lock and Tom Musser—testified primarily in opposition to the magnitude and impact of the proposed rate increase, including rate design issues. These customers voiced no current or ongoing service quality complaints affecting their utility service.

In its New Bern public hearing report filed on September 11, 2017, CWSNC responded to the testimony of witnesses Lock and Musser as follows (in part):

> Witnesses Lock and Musser voiced no current or ongoing service quality complaints affecting their utility service. CWSNC appreciates that fact and believes that the complete lack of any testimony at the New Bern public hearing describing service problems demonstrates that the Company is providing "adequate, efficient, and reasonable service" to its Fairfield Harbour customers, as required by G.S. 62-131(b).
>
> Regarding the testimony from witnesses Lock and Musser in opposition to the magnitude and impact of the proposed rate increase, CWSNC hereby incorporates by reference the discussion and explanation set forth above in conjunction with the Charlotte public hearing as the Company's response. As previously stated, rate increases, while controversial, are necessary to support prudent investment in the Company's capital-intensive water and sewer industry. In that regard, from

May 2016, to date, CWSNC invested approximately $550,000 for the...five water and sewer projects within the Fairfield Harbour service area...

[NOTE: The specific descriptions of these five projects were provided in CWSNC's September 11, 2017 report.]

(5) Wilmington (August 23, 2017)

Nine witnesses testified, one of whom (Frank Carroll) spoke on behalf of himself and 28 other customers from Belvedere Plantation (Belvedere) who appeared and stood to indicate their collective endorsement of public witness Carroll's comments.[1] Witness Carroll objected to the rate increase and complained about communications (generally), the number of service interruptions, the Boil Water Advisories (BWAs), hard water, the "chlorine smell," reliability and adequacy of the system, and "discoloration" of the water.

The other witnesses were all from, or served by, either the Belvedere or the Treasure Cove systems. Each customer who testified expressed concern about the proposed percentage increase in rates, and they variously raised issues about the level of service (including repairs and maintenance), water quality (in terms of particulate and hardness issues), customer communications, and rate equity among different kinds of service providers.

The service quality issues were principally confined to three areas: (1) a few instances where there was a "discolored" water supply at Belvedere, whether caused by water main breaks or by issues with the operation of a well; (2) hardness of the water; and (3) customer communications, including information relating to BWAs and the proposed rate increase. Other areas of customer focus included the differential between other providers' rates for water and wastewater service and the "average" rates for CWSNC, and the move towards uniform rates which is associated with a large percentage increase for the Treasure Cove customers.

In its post-hearing report filed on September 18, 2017, CWSNC offered specific responses to the customer service complaints which were voiced at the public hearing. For example, the following service quality concerns expressed by public witnesses Frank Carroll and Mandy Ware and the Company's responses to these concerns were contained in the Company's report filed on September 18, 2017 regarding the Wilmington public hearing.

In regard to the concerns voiced by public witness Carroll (whose testimony was approved and adopted by 28 additional customers at the public hearing), the Company responded as follows:

- Investment to improve quality of service and water quality. CWSNC has invested within Belvedere an estimated $4,855,759 since 2015 on various water and sewer capital projects. Much of the recent investment ($1,049,200) was for upgrades to Well Nos. 1 and 2, including an additional 150,000-gallon ground

[1] The Commission notes that the Company voluntarily met with a number of Belvedere customers on August 16, 2017, in Hampstead, North Carolina, the week prior to the Wilmington public hearing. Testimony in Wilmington indicated that approximately 120 interested residents attended the August meeting, along with CWSNC State President Matthew Klein and a number of his operational and executive staff members.

storage tank at Well No. 1; new pipeline and booster pumps at Well No. 1; SCADA controls and electrical wiring; and upgrades to Well No. 2 through a larger pump, a larger generator, new piping and SCADA controls to communicate with Well No. 1.

Additional recently-completed, active, and other planned investments to address the customers' concerns about "discolored water" and hardness, include:

- Installation of an automated flushing device on Hickory Drive in Belvedere on September 6, 2017, at a cost of $3,200;
- Commitment to resolve "hard water" concerns by installing appropriate treatment systems at Well Nos. 1 and 2 within approximately six (6) months. Acknowledging the support of the Belvedere customers, the Company is moving forward in a timely fashion on the design, permitting, and installation of these treatment systems. On August 17, 2017, CWSNC solicited quotes from an engineering firm for the costs to install the treatment systems. The cost is estimated to be approximately $800,000, including labor and parts.
- The Company identified the root cause of the "discolored water": sand from Well No. 2 was being brought up to the surface and pushed into the distribution system. The repair to Well No. 2 should be completed by September 25, 2017. Until then, CWSNC will continue to provide customers with clean, safe, drinking water from Well No. 1. The project cost is estimated to be between $30,000 and $50,000.

- Water Main Breaks. The Company's records show: (1) a two-inch water main break on March 14, 2017; (2) a booster pump failure due to a power surge at Well No. 1 on March 22, 2017; (3) another booster pump failure on April 19, 2017, due to a generator malfunction (which was corrected); (4) a well pump leak in the well-house on April 24, 2017; (5) a water main renovation on Greenview Court on April 25, 2017; (6) a pump failure at Well No. 1 requiring the use of Well No. 2[1]; (7) a repair necessitated on August 23, 2017, by a contractor's backhoe operator, who hit a water main; and (8) an eight-inch main split on September 12, 2017, due to improper installation of the water main on top of a boulder. All of these instances required issuance of BWAs by use of the "Voice Response" system, which delivers a voice message to the customer.

[1] In this instance, the Company resorted to using Well No. 2, rather than buying from Pender County, due to concern on behalf of its customers about the "GenX issue," which was much in the news at that time concerning all water sourced from the Cape Fear River. The start-up of Well No. 2—which had been off-line due to a capital improvement project—entailed some disruption and required emergency approval from the North Carolina Department of Environmental Quality. Nonetheless, the Company's judgment was a sound and reasonable exercise of concern on behalf of its customers, under those circumstances.

Water main breaks are inevitable for various reasons, including aged infrastructure and a failure, upon initial installation by a developer, to properly bed the pipe. Both the Company and customers are dependent upon the integrity of the initial installations, which were generally not performed by CWSNC. CWSNC apologizes for these service interruptions.

- Poor Communication About Boil Water Advisories. BWAs are issued by CWSNC to Belvedere customers in conjunction with each line break, and it should be emphasized that only the customers affected by a break are notified. The BWAs state the specific streets (i.e., customers) that were affected. These notices are delivered by the Voice Reach system after any water main break which necessitates the alert. CWSNC will also request that customers provide the Company with their best telephone and web-based contact information, in the event of future advisories. Receipt of proper customer contact information facilitates proper and prompt delivery of the required customer communication.

- Chlorination, Haloacetic Acids, and Total Trihalomethanes. Some customers expressed concern over haloacetic acids (HAA5s) and total trihalomethanes (TTHMs). HAA5s and TTHMs are unfortunate by-products of the water disinfection process (i.e., chlorine). CWSNC keeps the water safe, but commits to work to better address the HAA5 and TTHM by-products. The combination of the age of the water, the temperature of the water, and the amount of chlorine in the water can have an impact on the presence and amount of TTHMs and HAA5s. The Company does its best to monitor and control the HAA5s and TTHMs by: (1) flushing the water distribution mains; (2) keeping the chlorine at a low, but safe level (below the maximum of 4.0 milligrams per liter (mg/L) and more than the minimum of 0.02 mg/L); (3) seeking to better circulate (i.e., "loop") the water within the water mains to prevent "dead end" lines and improve water quality; and (4) deploying, where appropriate, automatic flushing devices throughout the water distribution system.

- GenX. As noted above, the Company has tested for GenX in its groundwater source in the Wilmington area and the reported results are "non-detect."

- Road repairs. Greenview Court was resurfaced on August 31, 2017.

In the Affidavit filed by witness Mendenhall on September 29, 2017, witness Mendenhall supplemented the Company's response set forth above regarding the Greenview Court road repairs, stating that:

> The Company accepts full responsibility for what it believes was an unacceptable delay in the repair to Greenview Court. Because of customer concerns expressed at the Hampstead meeting and the Wilmington hearing, the Company reviewed not only the Greenwood Court issue but also its practices and protocols regarding these types of road repairs. Specific factors involved with the Greenview Court matter included diversion of attention to capital projects, recent loss of staff

(turnover is often a significant problem with respect to attention to ancillary issues such as road repairs), and undue reliance on the paving contractor. Furthermore, CWSNC has discussed the importance of timeliness of these types of repairs with staff and expects, in the future, to ensure they are completed within ten (10) days.

Mandy Ware testified at the Wilmington public hearing regarding her concerns about water quality, communications, and price. Her objections included the cost and need for a constant supply of bottled water, the uncertainty about when the water will be usable for bathing her children, and the deposits left in her tub and sink from the water when it is discolored. The expense of a rate increase, combined with her additional costs to address the discoloration issues, were also a focus of her testimony.

In its post-hearing report, the Company responded to public witness Ware's testimony as follows:

> The Company apologizes to Ms. Ware for the inconvenience she has experienced due to the inconsistency in water quality. As indicated at the Hampstead public meeting on August 16, 2017 and reiterated above, the Company has rectified the "discoloration" issue (through the use of Well No. 1 and with the nearly-completed repair to Well No. 2) and is in the process of addressing the hardness issues that prompted several of Ms. Ware's concerns.

In the post-hearing Affidavit filed by witness Mendenhall, witness Mendenhall supplemented the Company's response set forth above regarding public witness Ware's testimony, stating that:

> I contacted Ms. Ware again on September 21, 2017, and she reported that—since the Wilmington public hearing—she has seen improvements in both water quality and customer communications. First, regarding water quality, Ms. Ware indicated that the "film" that had been covering her bathtub has not been present in the weeks since the August 23, 2017, public hearing. She further indicated that, aside from the unanticipated water main break on September 12, 2017, she has not detected "discolored water." Overall, Ms. Ware appears to have been pleased with the service CWSNC has provided to her within the past 30 days and seems to appreciate our efforts to resolve her water quality concerns.
>
> Second, regarding customer communications, a CWSNC staff member previously provided his cell number to Ms. Ware so she could communicate with the Company in the event of any further concerns. On September 21, 2017, Ms. Ware also was provided with my contact information—both e-mail and cell number. She confirmed receiving "Voice Reach" calls for the water main break on September 12, 2017, which included both the initial Boil Water Advisory and the Rescind notice. Ms. Ware was able to communicate directly with a CWSNC staff member to discuss how the water main break was impacting her water service. She also complimented CWSNC for promptly repairing the water main break and restoring her water service.

(6) Raleigh (August 28, 2017)

Four witnesses testified at the Raleigh public hearing. All witnesses objected to the amount of the rate increase, two customers focused on rate design and cross-subsidy issues, and two customers spoke to their concern about the financial impact of the rate increase on some customers. Public witness Vincent P. Roy commended the Public Staff, as well as the work performed with CWSNC representatives (i.e., Danny Lassiter and his team) in quarterly meetings with his homeowners' association, held over "...the last several years." Witness Roy also addressed concerns about an inconsistent ability to reach help via the Company's customer service line. No other service-related complaints were expressed at the Raleigh public hearing.

In its Raleigh public hearing report, the Company responded, in part, to customer testimony, and public witness Roy in particular, as follows:

> The General Response section, above, addresses the benefits of uniform rates, which balance and mitigate the burden of repairs by spreading them more broadly across the CWSNC system. Consolidated corporate organization and rate structures have many obvious and demonstrated benefits, and the Company is committed to moving towards rate uniformity over time. However, in recognition of the impact on some customers in the system, the Company is moving incrementally towards that uniformity, as is demonstrated by the stipulated rates in this case which create four rate divisions. It should also be noted that since 2009, CWSNC has invested approximately $928,500 in Carolina Trace.
>
> The arguments about rate design, specifically about the ratio of fixed to volumetric costs, are legion, but the essential truth is this—to tilt too far in either direction is to decidedly favor one group of customers over another. The key is balance, and the Company submits that the proposed settlement in this case achieves that balance.
>
> As to assurance of efficiency, the Company urges all customers to understand the level of scrutiny that is imposed in the Public Staff's examination of this case – an examination that plumbs the details of Company books and management and operational decisions to ensure that rates are based on costs that flow from efficient, reasonable operation of the Company. Over fifteen (15) weeks of discovery, the Public Staff propounded fifty-four (54) sets of data requests and numerous follow-up questions and conversations. The Public Staff also conducted field inspections of the water systems at Ski Mountain, Crestview, Misty Mountain, Chapel Hill, Powder Horn Mountain, Fairfield Harbor, Belvedere Plantation, Olde Point, Treasure Cove, Bradfield Farms, Wildlife Bay, Zemosa Acres, and Kings Grant, and of the sewer systems at Fairfield Harbor, Belvedere Plantation, Bradfield Farms, Danby, Independent/Hemby and Kings Grant. Statewide public hearings were held by the Commission, and attended by representatives of the Public Staff and the Company, in Asheville, Boone, Charlotte, New Bern, Wilmington, and Raleigh. An evidentiary hearing will be held in Raleigh on September 20, 2017, to receive evidence and to examine the expert witnesses. Additionally, the Public Staff followed up on written customer protests and concerns raised at the public hearings

and through e-mails and letters, and reviewed relevant North Carolina Department of Environmental Quality ("DEQ") records. The rate-setting process is rigorous and intensive, as it should be, and the burden of proof is on the utility to prove in a judicial arena that it merits additional rates.

The Raleigh public hearing report also contained the Company's responses regarding issues such as actions being taken by CWSNC to improve communications with customers, system investments undertaken to improve quality of service and water quality provided to customers, and others matters.

(7) Raleigh Evidentiary Hearing (September 20, 2017)

Two witnesses testified at the beginning of the evidentiary hearing. Public witness Bryan McCabe testified on behalf of the Pender County Board of Commissioners in opposition to the proposed rate increase and asserted that Belvedere customers "have experienced multiple service issues, including pressure problems and discolored water, which made cleaning themselves, their dishes, and their homes futile, and often ruined any light-colored clothes which they washed." Public witness Vincent P. Roy briefly repeated portions of the testimony which he previously offered on August 28, 2017 at the Raleigh public hearing.

Public Staff witness Casselberry testified that her investigation included review of customer complaints; contact with the North Carolina Department of Environmental Quality (DEQ) and the Water Quality and Public Water Supply Sections of the Division of Water Resources (DWR); and review of Company records and analysis of revenues at existing and proposed rates. Witness Casselberry testified that she had contacted representatives of all DEQ regional offices regarding the operation of the CWSNC water and sewer systems. She testified that none of the regional office personnel she contacted expressed any major concerns with the water and sewer systems serving CWSNC customers or identified any major water quality concerns.

Further, witness Casselberry testified that the Public Staff received approximately 120 email messages or letters from CWSNC customers. Witness Casselberry observed that one complaint was from Abington, six were from Belvedere, three were from Bradfield Farms, 63 were from Carolina Trace, 19 were from Connestee Falls, one was from Fairfield Mountain, two were from Mt. Carmel, two were from Mt. Mitchell, seven were from Sapphire Valley, one was from Sugar Mountain, five were from Treasure Cove, one was from Watauga Vista, one was from Woodhaven, and eight were from unspecified service areas. She indicated that all customers objected to the magnitude of the rate increase. Many complaints received were concerning the corporate structure, rate of return, the notice to customers, and rate design. Further, witness Casselberry testified that numerous complaints received pertained to rate comparisons between CWSNC's current and proposed rates and the rates of municipalities in North Carolina and other states. She offered testimony in response to each of these customer concerns.

In regard to the service and water quality complaints registered by customers at each of the six public hearings, witness Casselberry stated that she had read each of the three reports filed by CWSNC in response to the customer concerns and complaints which were included in testimony at those six public hearings. Witness Casselberry specifically commended CWSNC in one instance for its "thorough response to customer complaints" and further testified that she, speaking for the Public Staff, was satisfied with the Company's responses in all three reports and had no recommendations.

With specific reference to the Belvedere and Treasure Cove systems, witness Casselberry testified that:

> In regard to the situation at Belvedere, CWSNC informed the Public Staff about the problems they were having with well No. 2 and their decision not to activate the emergency connection with Pender County. The Public Staff agreed with their decision. Prior to the hearing held on August 23, 2017, I inspected the water and sewer systems serving Belvedere. At the time of my inspection, Well No. 2 was running clear.
>
> On August 24, 2017, I inspected the water system serving Treasure Cove. The ditch causing floods is not a ditch but a small creek which runs parallels [*sic*] to the well lot. The well lot was mowed with the exception of approximately two feet along the bank of the creek. It is the Public Staff's opinion that the well lot is being properly maintained.
>
> No party contested the contents of the three service reports filed by the Company.

Based upon the foregoing, and after careful review of the testimony of the customers at the public hearings, the testimony of Company witness Mendenhall, the Reports on Customer Comments provided by CWSNC, the Public Staff's engineering and service quality investigation, and the late-filed affidavits and exhibits filed by CWSNC and the Public Staff, the Commission concludes that the overall quality of service provided by CWSNC is adequate.

II. Capital Structure and Cost of Capital

In its Application the Company requested an overall cost of capital of 8.55%. Such request was based on a capital structure of 47.11% long-term debt, 52.89% common equity, an embedded cost of debt of 6.58%, and a return on common equity of 10.30%. In the direct testimony of witness Linneman filed on August 7, 2017, in support of the Company's request to increase rates, witness Linneman testified that since the filing of the Application the Company and the Public Staff have negotiated a settlement regarding the rate of return and capital structure issues. Pursuant to the First Stipulation filed on August 7, 2017, CWSNC and the Public Staff agreed that a capital structure consisting of 48.00% long-term debt and 52.00% common equity, an embedded cost of debt of 5.93%, and a return on common equity of 9.60% are appropriate for use in this proceeding.

Public Staff witness Craig testified in support of the agreed-upon capital structure and cost rates on the components of the capital structure. Witness Craig contended that it is widely recognized that a public utility should be allowed a rate of return on capital that will allow the utility, under prudent management, to attract capital under the criteria or standards referenced by the Hope[1] and Bluefield[2] decisions. He maintained that if the allowed rate of return is set too high, consumers are burdened with excessive costs, current investors receive a windfall, and the utility has an incentive to overinvest. However, if the return is set too low and the utility is not able to attract capital on reasonable terms to meet future expansion for its service area, witness Craig asserted that future service obligations may be impaired. Witness Craig explained that because a public utility is capital intensive, the cost of capital is a very large part of its overall revenue requirement and is a crucial issue for a company and its ratepayers.

With respect to capital structure, witness Craig testified that in this proceeding, through discovery, it was determined that CWSNC was in position to update its capital structure to 47.32% long-term debt and 52.68% common equity; however, as part of the First Stipulation, CWSNC agreed to a lower (i.e., less expensive) cost capital structure consisting of 48.00% long-term debt and 52.00% common equity.

With respect to the cost of common equity, witness Craig testified that his recommendation is based on: (1) the discounted cash flow (DCF) model for water companies; and (2) the risk premium method using a regression analysis of allowed returns for water utilities. He testified that because the common equity of CWSNC is not publicly traded, he could not apply the DCF method directly to CWSNC. As such, he applied the DCF method to a comparable group of water utilities followed by Value Line Investment Survey (Value Line). Witness Craig testified that, based upon the DCF results for the comparable group of water utilities, he determined that the cost of common equity for CWSNC is within the range of 8.30% to 9.70%. He further testified that applying the risk premium method produced a predicted return on common equity of 9.65%. Based upon the results of the DCF and risk premium methods, witness Craig concluded that a reasonable range of estimates for the cost of equity for CWSNC is between 8.30% and 9.70%.

Witness Craig testified that, consistent with his analysis, he supported the stipulated settlement regarding a 9.60% return on common equity as being a reasonable compromise in this case.

Witness Craig also testified as to the extent to which the recommended cost of common equity takes into consideration the impact of changing economic conditions on customers. He testified that he is aware of no clear numerical basis for quantifying the impact of changing economic conditions on customers in determining an appropriate return on equity in setting rates for a public utility. Rather, he stated that the impact of changing economic conditions nationwide is inherent in the methods and data used in his study to determine the cost of equity for utilities that are comparable in risk to CWSNC. In addition, witness Craig stated that customer testimony at the public hearings in this proceeding focused on the amount of proposed rate increases in the various service areas and that there was no customer testimony on the impact of changing economic conditions on the Company's cost of equity capital.

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[1] Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

[2] Bluefield Waterworks & Impr. Co. v. Public Service Comm'n, 262 U.S. 679, 692-93 (1923).

In order to obtain information on the economic conditions in the area served by CWSNC, witness Craig testified that he conducted a review of the data on total personal income for the years 2013 through 2015 as compiled by the Bureau of Economic Analysis (BEA) and data on the unemployment rate published by the North Carolina Department of Commerce for the counties within the Company's service area which have the greatest number of CWSNC customers. The Company's service area, which stretches from the mountains to the coast, consists of 38 counties and includes nine of the 10 most populous counties in North Carolina.

According to witness Craig, the three largest counties within the Company's service area, Forsyth, Mecklenburg, and Wake, experienced average growth in personal income of more than 3.7% annually during the years 2013 through 2015, while the statewide average was 3.5%. Most of the counties within its service area experienced growth in personal income from 2013 through 2015, and the overall annual average for these counties was 3.5%.

Witness Craig testified that the average unemployment rate of the 38 counties in the CWSNC service territory was 5.0% at the end of 2016, which was virtually identical to North Carolina's statewide unemployment rate of 4.9% at the end of 2016. From 2014 through 2016, the unemployment rate in the Company's service territory fell from 5.6% in 2014 to 5.0%, while the state unemployment rate fell from 5.4% in 2014 to 4.9%. The falling unemployment rate in the Company's service territory demonstrates the continued improvement in North Carolina's economy and the economy of the service territory of CWSNC.

Witness Craig stated that the determination of the rate of return for regulatory purposes must be based on the requirements of capital markets. However, as noted by the North Carolina Supreme Court in recent decisions, it is necessary to consider the impact of changing economic conditions on consumers in general rate cases. Witness Craig testified that, as noted in his discussion on present economic conditions, there are reasons to believe that the economic conditions in the nation and in North Carolina will continue to improve which should provide a benefit for many CWSNC customers.

In regard to the cost of debt, witness Craig testified that he determined that the Company's embedded cost of debt is 5.93%. He explained that the individual debt issues have contractual agreements explicitly stating the cost of each issue. Thus, the embedded annual cost of debt may be calculated by simply considering these contractual agreements and the utility's books and records.

Company witness Linneman provided a late-filed affidavit wherein, among other matters, witness Linneman stated that the stipulated embedded cost of debt of 5.93% is a weighted average cost based on the long-term debt which was issued in 2006 at a cost of 6.58% and the cost of the revolving balance loan which was issued in 2015 and carries a variable interest rate that has fluctuated from a low of 1.70% in 2015 to a high of 2.45% in May 2017. He also commented that the long-term debt also includes a "make whole" penalty payment requirement in excess of $50 million, should the debt be refinanced or paid in full prior to the maturity date of July 21, 2036. He further observed that there is no debt rating for Utilities, Inc.'s current outstanding debt since the debt is in the form of a commercial loan. Therefore, no debt rating is assigned to it, as would be in the case if the outstanding debt were in the form of a bond issuance.

With respect to the overall cost of capital, witness Craig recommended 7.84% as set forth in Exhibit CCC-5 of his testimony. In regard to a reasonableness assessment of financial risk with respect to his recommended return on common equity and overall cost of capital, witness Craig testified that he considered the pretax interest coverage ratio. Witness Craig testified that, based upon the recommended capital structure, cost of debt, and common equity return of 9.60%, the pretax interest coverage ratio is approximately 3.7 times, which should allow the Company to qualify for a "BBB" bond rating.

G.S. 62-133(b)(4) requires the Commission to fix rates for service which will enable a public utility, by sound management, to produce a fair profit for its stockholders, in view of current economic conditions, maintain its facilities and services and compete in the market for capital, and no more. This is the ultimate objective of ratemaking. Utilities Commission v. General Telephone Company, 281 N.C. 318, 189 S.E.2d 705 (1972). The Commission is of the opinion that there is adequate evidence in the record to support the return on equity agreed to by the Public Staff and CWSNC and that such return should allow CWSNC to properly maintain its facilities and services, provide adequate service to its customers, and produce a fair return, thus enabling the Company to attract capital on terms that are fair and reasonable to its customers and investors. Consequently, the Commission finds and concludes that the return on common equity of 9.60% that was agreed to by CWSNC and the Public Staff is just and reasonable and should be approved.

Further, in light of Public Staff witness Craig's testimony, analysis, and exhibits (including both his direct and late-filed exhibits) and the direct testimony of CWSNC witness Linneman in support of the First Stipulation (as well as his late-filed Affidavit and exhibits), the Commission finds and concludes that there is adequate and substantial evidence in the record to support the capital structure and cost of debt agreed to by CWSNC and the Public Staff. Therefore, the capital structure consisting of 52.00% common equity and 48.00% long-term debt, an embedded cost of debt of 5.93%, and a return on common equity of 9.60% are appropriate for use in this proceeding considering the impact of changing economic conditions on customers and relevant statutory and case law.

III. Rate Design Issues

As noted by CWSNC in its Rate Case Application and the testimony of Company witness Linneman, this is the first general rate case filed by the Company since the merger was approved by the Commission on August 17, 2016. By its Application, CWSNC proposed to establish four Rate Divisions for ratemaking purposes in this proceeding as follows:

CWSNC Uniform Water
CWSNC Uniform Sewer
Bradfield Farms/Fairfield Harbour Water[1]
Bradfield Farms/Fairfield Harbour Sewer

Under the Company's proposed rate design, the CWSNC Uniform Water and Sewer Rate Divisions will consist of all water and sewer systems currently owned and operated by the Company, but excluding the Bradfield Farms and Fairfield Harbour service areas. The Bradfield

[1] Bradfield Farms is located in Mecklenburg County and Fairfield Harbour is located in Craven County.

Farms and Fairfield Harbour water and sewer service areas have been combined into separate Water and Sewer Rate Divisions for purposes of this case. CWSNC's Application states that its ultimate goal, in future general rate cases, is to move Bradfield Farms and Fairfield Harbour into the CWSNC Uniform Water and Sewer Rate Divisions. Additionally, in order to reduce "rate shock" for customers in the Treasure Cove service area who are presently included in CWSNC's Uniform Water and Sewer Rate Divisions, the Company and the Public Staff proposed that Treasure Cove's customers be charged the same water and sewer rates as the Bradfield Farms and Fairfield Harbour customers.

Further, as a matter of rate design in this case, CWSNC proposed no rate changes for customers in the Company's Elk River and CLMS service areas. Because customers in the Elk River service area were impacted by a recent rate increase effective September 20, 2016, the Company stated that it is reluctant, at this time, to further increase rates for those particular customers by applying CWSNC's uniform water and sewer rates to them. According to the Company, this course of action will be reevaluated in the Company's next rate case.

As for the CLMS service area, CWSNC stated that its proposal to not increase (but to hold constant) the water and sewer rates for those affected customers is consistent with the ratemaking and rate design approved by the Commission in the Company's last two general rate cases (Docket Nos. W-354, Subs 336 and 344) and will continue the orderly process of moving the CLMS service area toward full inclusion in the Company's uniform water and sewer rates in future general rate cases.

The Public Staff, through the Second Stipulation, agreed with CWSNC regarding the above-summarized rate design proposals. With respect to the base facility charge for residential sewer customers, in the Second Stipulation the parties agreed that for purposes of this rate case proceeding, in recognition of the significant impact the Company's proposed sewer base facility charge would have on a relatively small number of residential customers in this case, all residential sewer customers should pay the same base facility charge regardless of meter size.

In regard metered sewer rates for customers in Fairfield Harbour, Bradfield Farms, and Sapphire Valley service areas, in the Second Stipulation CWSNC agreed to consider implementing metered sewer rates for customers in these service areas in the Company's next general rate case filing and reserved the right to independently propose metered sewer rates for these systems.

With respect to the rates proposed for the CLMS service area, in its letter filed with the Commission on October 24, 2017, CLCA commented that system-specific rates were instituted for the CLMS service area in 2009 in Docket No. W-354, Sub 314, and the system specific rates were continued in 2011 in Docket No. W-354, Sub 327. CLCA stated that in 2013, the first efforts were made to begin returning the CLMS service area's system-specific rates to the uniform rates. CLCA noted that these efforts continued in 2015, and now continue in 2017. CLCA stated that recent actions by the Commission, the Public Staff, and CWSNC have brought CLMS service area's system-specific rates closer to parity within recent years and that the CLCA "remains patient and understands the need to gradually return its rates to parity". CLCA recognized that the Stipulation between the Public Staff and CLCA in this proceeding continues to move rates for the CLMS service area closer to parity, and consequently, expressed no objections to the aforementioned rate design proposals.

The Commission finds good cause to approve the rate design proposals as set forth above for the reasons given by the Company in its Application and in the testimony of CWSNC witness Linneman and given the Public Staff's support for such proposals as evidenced by the Second Stipulation and the testimony of Public Staff witness Casselberry. Moreover, the Commission recognizes that CLCA stated it does not object to the Stipulation between the Public Staff and CWSNC which included the rate design proposals discussed herein. Consequently, the Commission finds and concludes that the rate design proposals as set forth above are just and reasonable and should be approved.

Furthermore, the Commission finds and concludes that CWSNC should consider implementing metered sewer rates for customers in the Fairfield Harbour, Bradfield Farms, and Sapphire Valley service areas in the Company's next general rate case filing or should independently propose metered sewer rates for these systems, as stipulated.

IV. WSIC and SSIC

CWSNC witness Linneman testified that, pursuant to G.S. 62-133.12 and Commission Rules R7-39 and R10-26, in the Company's general rate case proceedings in Docket Nos. W-354, Subs 336 and 344, the Commission found it to be in the public interest to authorize CWSNC 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. Witness Linneman commented that, as a result, CWSNC was authorized to implement a WSIC/SSIC rate adjustment mechanism for recovery of such costs applicable to all of the Company's pre-merger customers.[1]

Witness Linneman noted that all of CWSNC's post-merger customers are subject to the application in this general rate case.[2] Therefore, witness Linneman contended that the Company's

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[1] CWS Systems, Inc. and Elk River Utilities, Inc. were also authorized by the Commission to implement WSIC/SSIC Mechanisms in their last pre-merger general rate cases in Docket Nos. W-778, Sub 91 and W-1058, Sub 7, respectively. Bradfield Farms Water Company, Carolina Trace Utilities, Inc., and Transylvania Utilities, Inc. did not have pre-merger general rate cases by which those companies were authorized to implement WSIC/SSIC Mechanisms; thus, to date, the WSIC/SSIC Mechanisms are not authorized and in effect for the Bradfield Farms, Carolina Trace, and Transylvania post-merger CWSNC service territories. In Paragraph 16 of its Application, CWSNC requested that the Commission specifically find and conclude that the Company's Commission-authorized WSIC/SSIC Mechanisms will, going-forward, apply to all customers now served by CWSNC on a post-merger basis.

[2] Decretal Paragraph 9 of the August 17, 2016 Order Approving Merger in Docket Nos. W-354, Sub 350, et al., provides as follows:

> That the WSIC and SSIC Mechanisms currently in effect for CWSNC and CWSS (and Elk River, if approved by the Commission in its pending rate case in Docket No. W-1058, Sub 7) shall continue in effect post-merger, **but shall not apply to customers in the Bradfield Farms, Carolina Trace, or Transylvania service areas until such time as CWSNC has either (1) a consolidated general rate case affecting the rates applicable to customers in the areas currently served by Bradfield Farms, Carolina Trace, and/or Transylvania**; or (2) a stand-alone general rate case or cases where the Company proposes implementation of a separate WSIC/SSIC Mechanism specific to one or more of the areas currently served by Bradfield Farms, Carolina Trace, or Transylvania. (Emphasis added)

Commission-authorized WSIC/SSIC Mechanisms will, on a going-forward basis, apply to all customers served by CWSNC, including those customers incorporated into the Company as a result of the Commission-authorized 2016 corporate merger. Consequently, witness Linneman requested that the Commission specifically find and conclude that it is in the public interest for CWSNC's Commission-authorized WSIC/SSIC Mechanisms to henceforth apply to all customers now served by CWSNC on a post-merger basis. Further, witness Linneman stated that consistent with Commission Rules R7-39(c)(1) and R10-26(c)(1), the Company's Ongoing Three-Year Plan was included as Appendix C to the Rate Case Application filed by CWSNC on March 31, 2017.

In Paragraph 11 of the Second Stipulation, the Public Staff and CWSNC agreed that, pursuant to Commission Rules R7-39(k) and R10-26(k), CWSNC's Commission-authorized WSIC and SSIC surcharges will be reset to zero as of the effective date of new base rates established in this general rate case. Thereafter, only the incremental depreciation expense and capital costs of new eligible water and sewer system improvements that have not previously been reflected in the Company's rates will be recoverable through the WSIC/SSIC Mechanisms on a going-forward basis.

Moreover, the Public Staff and CWSNC agreed that all of CWSNC's post-merger customers are subject to the Application in this general rate case. As a result, the Stipulating Parties acknowledged and agreed that the Company's Commission-authorized WSIC/SSIC Mechanisms will, on a going-forward basis, apply to all customers served by CWSNC, including those customers incorporated into the Company as a result of the Commission-authorized 2016 corporate merger.

Further, in Paragraph 11 of the Second Stipulation, the Public Staff and CWSNC agreed that the Company's Ongoing Three-Year Plan filed by CWSNC in this docket is reasonable and meets the requirements of Commission Rules R7-39(m) and R10-26(m).

Accordingly, the Commission is persuaded by Paragraph 11 of the Second Stipulation and the testimony of CWSNC witness Linneman that it is in the public interest for CWSNC's Commission-authorized WSIC/SSIC Mechanisms to henceforth apply to all customers now served by CWSNC on a post-merger basis, subject to all statutory and regulatory requirements. The Commission finds and concludes that the three-year plan filed by CWSNC in this proceeding supports this conclusion. Furthermore, the Commission finds and concludes that the previously-authorized water and sewer system improvement charge rate adjustment mechanism continues in effect, although, pursuant to Commission Rules R7-39(k) and R10-26(k), it has been reset at zero as of the effective date of this Order. CWSNC may, under the Rules and Regulations of the Commission, next apply for a WSIC/SSIC rate surcharge on February 1, 2018, to become effective April 1, 2018. The Commission acknowledges that 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. Further, the WSIC/SSIC surcharge is subject to Commission approval and to audit and refund provisions. Moreover, 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.

Based on the service revenues set forth in the Second Stipulation and approved herein, the maximum revenues that could be recovered through WSIC/SSIC charges as of the effective date of this Order are:

	Service Revenues		WSIC & SSIC Cap
CWSNC Uniform Water	$17,415,028	x 5% =	$870,751
CWSNC Uniform Sewer	12,627,226	x 5% =	631,361
BF/FH Water	950,755	x 5% =	47,538
BF/FH Sewer	1,733,316	x 5% =	86,666

V. Overall Conclusions

The Commission, having carefully reviewed the First Stipulation, the Second Stipulation, and all of the evidence of record, finds and concludes that the First Stipulation and Second Stipulation are the product of the give-and-take settlement negotiations between CWSNC and the Public Staff; that they constitute material evidence; that they are entitled to be given appropriate weight in this proceeding, along with all other evidence in the record; and that they are fully supported by competent evidence in the record. Further, the Commission recognizes that CLCA stated in its October 24, 2017 filing that it does not object to the Stipulation between the Public Staff and CWSNC.

Accordingly, based on the foregoing findings of fact and the entire record in this proceeding, the Commission concludes that the stipulated rates, the stipulated capital structure and rate of return percentages, and all of the other provisions of the First and Second Stipulations, which are incorporated herein by reference, are just and reasonable and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the First Stipulation and the Second Stipulation are incorporated by reference herein and are hereby approved in their entirety.

2. That the Schedules of Rates, attached hereto as Appendices A-1, A-2, A-3, and A-4, and the Schedules of Connection Fees for Uniform Water and Uniform Sewer, attached hereto as Appendices B-1 and B-2, are hereby approved and deemed to be filed with the Commission pursuant to G.S. 62-138.

3. That the Schedules of Rates, attached hereto as Appendices A-1, A-2, A-3, and A-4, are hereby authorized to become effective for service rendered on and after the issuance date of this Order.

4. That the Notices to Customers, attached hereto as Appendices C-1 and C-2 shall be mailed with sufficient postage or hand delivered to all affected customers in each relevant service area, respectively, in conjunction with the next regularly scheduled billing process.

5. That CWSNC shall file the attached Certificate of Service, properly signed and notarized, not later than 10 days after the Notices to Customers are mailed or hand delivered to customers.

6. That the First Stipulation, the Second Stipulation, and the parts of this Order pertaining to the contents of those agreements shall not be cited or treated as precedent in future proceedings.

7. That CWSNC shall consider implementing metered sewer rates for customers in the Fairfield Harbour, Bradfield Farms, and Sapphire Valley service areas in the Company's next general rate case filing or shall independently propose metered sewer rates for these systems, as stipulated.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of November, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

APPENDIX A-1
PAGE 1 OF 7

SCHEDULE OF RATES

for

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

for providing water and sewer utility service

in

ALL OF ITS SERVICE AREAS IN NORTH CAROLINA

(excluding Corolla Light, Monteray Shores, Elk River Development, Fairfield Harbour Service Area, Treasure Cove, Register Place Estates, North Hills and Glen Arbor/North Bend Subdivisions, Bradfield Farms, Larkhaven, Silverton and Woodland Farms Subdivisions and Hawthorne at the Green Apartments

WATER RATES AND CHARGES

Monthly Metered Water Service (Residential and Commercial):

Base Facility Charge (based on meter size with zero usage)

< 1" meter	$ 24.44
1" meter	$ 61.10
1 1/2" meter	$ 122.20
2" meter	$ 195.52
3" meter	$ 366.60
4" meter	$ 611.00
6" meter	$1,222.00

Usage Charge:

A. Treated Water, per 1,000 gallons	$ 7.70
B. Untreated Water, per 1,000 gallons (Brandywine Bay Irrigation Water)	$ 4.11

C. Purchased Water for Resale, per 1,000 gallons:

Service Area	Bulk Provider		
Carolina Forest	Montgomery County	$	3.19
High Vista Estates	City of Hendersonville	$	3.25
Riverpointe	Charlotte Water	$	6.30
Whispering Pines	Town of Southern Pines	$	2.23
White Oak Plantation/ Lee Forest	Johnston County	$	2.28
Winston Plantation	Johnston County	$	2.28
Winston Point	Johnston County	$	2.28
Woodrun	Montgomery County	$	3.19
Yorktown	City of Winston-Salem	$	5.01
Zemosa Acres	City of Concord	$	5.27
Carolina Trace	City of Sanford	$	2.21

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

When because of the method of water line installation utilized by the developer or owner, it is impractical to meter each unit or other structure separately, the following will apply:

Sugar Mountain Service Area:
Where service to multiple units or other structures is provided through a single meter, the average usage for each unit or structure served by that meter will be calculated. Each unit or structure will be billed based upon that average usage plus the base monthly charge for a <1" meter.

Mount Mitchell Service Area:
Service will be billed based upon the Commission-approved monthly flat rate.

Monthly Flat Rate Water Service: (Billed in Arrears) $ 47.45

Availability Rate: (Semiannual)

Applicable only to property owners in Carolina Forest and Woodrun Subdivisions in Montgomery County $ 24.65

WATER AND SEWER – RATE INCREASE

Availability Rate: (Monthly)	
Applicable only to property owners in Linville Ridge Subdivision	$ 12.35
Availability Rate: (Monthly)	
Applicable only to property owners in Fairfield Sapphire Valley Service Area	$ 9.10
Availability Rate: (Monthly)	
Applicable only to property owners in Connestee Falls	$ 4.80
Meter Testing Fee: 1/	$ 20.00
New Water Customer Charge:	$ 27.00
Reconnection Charge: 2/	
If water service is cut off by utility for good cause	$ 27.00
If water service is discontinued at customer's request	$ 27.00
Reconnection Charge: 3/ (Flat-rate water customers)	
If water service is cut off by utility for good cause	Actual Cost
Management Fee: (in the following subdivisions only)	
Wolf Laurel	$150.00
Covington Cross Subdivision (Phases 1 & 2)	$100.00
Oversizing Fee: (in the following subdivision only)	
Winghurst	$400.00
Meter Fee:	
For <1" meter	$ 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)	$ 45.97
Commercial (based on meter size with zero usage)	
< 1" meter	$ 45.97
1" meter	$ 114.93
1 1/2" meter	$ 229.85
2" meter	$ 367.76
3" meter	$ 689.55
4" meter	$1,149.25
6" meter	$2,298.50

B. Usage Charge, per 1,000 gallons (based on metered water usage)	$ 3.11

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

Monthly Metered Purchased Sewer Service:

Collection Charge (Residential and Commercial/per SFE (Single Family Equivalent)	$ 36.75

Usage charge, per 1,000 gallons based on purchased water consumption

Service Area	Bulk Provider	
White Oak Plantation/ Lee Forest/Winston Pt.	Johnston County	$ 4.82
Kings Grant	Two Rivers Utilities	$ 3.80
College Park	Town of Dallas	$ 5.70

Monthly Flat Rate Sewer Service:	$ 56.57
Multi-residential customers who are served by a master meter shall be charged the flat rate per unit.	$ 56.57

Mt. Carmel Subdivision Service Area:

Monthly Base Facility Charge	$ 6.77
Monthly Collection Charge (Residential and Commercial/SFE)	$ 36.75
Usage Charge, per 1,000 gallons based on purchased water consumption	$ 5.88

Regalwood and White Oak Estates Subdivision Service Areas:

Monthly Flat Rate Sewer Service	
Residential Service	$ 56.57
White Oak High School	$1,770.10
Child Castle Daycare	$ 219.90
Pantry	$ 116.80

Fairfield Mountain/Apple Valley (a.k.a. Rumbling Bald) Service Area and Highland Shores Subdivision

Monthly Sewer Rates:

Residential	
Collection charge/dwelling unit	$ 36.75
Treatment charge/dwelling unit	$ 69.50
Total monthly flat rate/dwelling unit	$ 106.25
Commercial and Other:	
Minimum monthly collection and treatment charge	$ 106.25
Monthly collection and treatment charge for customers who do not take water service (per SFE)	$ 106.25
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

Availability Rate: (Monthly)

Applicable only to property owners in Fairfield Sapphire Valley Service Area	$	8.30

Availability Rate: (Monthly)

Applicable only to property owners in Connestee Falls	$	4.70
New Sewer Customer Charge: [4/]	$	27.00

Reconnection Charge: [5/]

If sewer service is cut off by utility for good cause	Actual Cost

MISCELLANEOUS UTILITY MATTERS

Charge for processing NSF Checks:	$ 25.00
Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Billing Frequency:	Bills shall be rendered monthly in all service areas, except for Mt. Carmel, which will be billed bimonthly. Availability rates will be billed quarterly in advance for Connestee Falls, semiannually in advance for Carolina Forest, Woodrun, and Fairfield Sapphire Valley, and monthly for Linville Ridge.
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

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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 the customer with the 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 356, on this the 8th day of November, 2017.

APPENDIX A-2
PAGE 1 OF 3

SCHEDULE OF RATES

for

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

for providing sewer utility service

in

COROLLA LIGHT AND MONTERAY SHORES SERVICE AREA

WATER AND SEWER – RATE INCREASE

SEWER RATES AND CHARGES

Monthly Metered Sewer Service (Residential and Commercial):

Base Facility Charge (based on meter size with zero usage)

< 1" meter	$ 52.06
1" meter	$ 130.15
1 1/2" meter	$ 260.31
2" meter	$ 416.49
3" meter	$ 780.92
4" meter	$1,301.54
6" meter	$2,603.07

Usage Charge, per 1,000 gallons (based on purchased water usage)	$ 6.62

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

New Sewer Customer Charge:	$ 21.92

Reconnection Charge: 1/

If sewer service cut off by utility for good cause	Actual Cost

APPENDIX A-2
PAGE 2 OF 3

Uniform Connection Fees: 2/

The following uniform connection fees apply unless specified differently by contract approved by and on file with the North Carolina Utilities Commission.

Connection Charge (CC), per SFE (Single Family Equivalent)	$ 100.00
Plant Modification Fee (PMF), per SFE	$1,000.00

The systems where connection fees other than the uniform fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows. These fees are per SFE:

WATER AND SEWER – RATE INCREASE

Subdivision	CC	PMF
Corolla Light	\$ 700.00	\$ 0.00
Monteray Shores	\$ 700.00	\$ 0.00
Monteray Shores (Degabrielle Bldrs.)	\$ 0.00	\$ 0.00
Corolla Bay[3/]	\$ 100.00	\$1,000.00
Corolla Bay[4/]	\$ 700.00	\$ 0.00
Corolla Shores	\$ 700.00	\$ 0.00

One SFE shall equal 360 gallons per day of capacity.

MISCELLANEOUS UTILITY MATTERS

Charge for processing NSF Checks:	\$ 24.91
Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Billing Frequency:	Bills shall be rendered monthly
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Notes:

[1/] The Utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish the estimate to the customer with the cut-off notice.

Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

[2/] These fees are only applicable one time, when the unit is initially connected to the system.

[3/] The connection charge of \$100 per SFE and the plant modification fee of \$1,000 per SFE specified herein apply to new wastewater connections requested at Corolla Bay prior to June 4, 2015.

[4/] The connection charge of \$700 per SFE applies to new wastewater connections requested at Corolla Bay on and after June 4, 2015.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 356, on this the 8th day of November, 2017.

WATER AND SEWER – RATE INCREASE

APPENDIX A-3
PAGE 1 OF 2

SCHEDULE OF RATES

for

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

for providing water and sewer utility service

in

ELK RIVER DEVELOPMENT

WATER UTILITY SERVICE

Monthly Metered Water Service: (Residential and Non-residential)

Base Facility Charge (based on meter size with zero usage)

< 1" meter	$ 19.52
1" meter	$ 48.79
2" meter	$ 156.12

Usage Charge, per 1,000 gallons $ 4.29

SEWER UTILITY SERVICE

Monthly Metered Sewer Service: (Residential and Non-residential)

Base facility Charge (based on meter size with zero usage)

< 1" meter	$ 23.38
1" meter	$ 58.45
2" meter	$ 187.05

Usage Charge, per 1,000 gallons $ 3.00
(based on metered water usage)

Connection Charge:

Water	$1,000.00
Sewer	$1,200.00

WATER AND SEWER – RATE INCREASE

APPENDIX A-3
PAGE 2 OF 2

Reconnection Charge:

If water service is cut off by utility for good cause	$26.92
If water service is disconnected at customer's request	$26.92
If sewer service is cut off by utility for good cause	Actual Cost [1]

[1] The utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish this estimate to the customer with the cut-off notice. This charge will be waived if customer also receives water service from the utility within the same service area.

(Customers who ask to be reconnected within nine months of disconnection will be charged the approved base facility charges for water and sewer for the service period during which they were disconnected.)

New Water Customer Charge:	$26.92
Bills due:	On billing date
Bills Past Due:	21 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Returned Check Charge:	$24.93
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.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 356, on this 8th day of November, 2017.

APPENDIX A-4
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 AND WOODLAND FARMS SUBDIVISIONS AND HAWTHORNE AT THE GREEN APARTMENTS

WATER RATES AND CHARGES

Monthly Metered Service (Residential and Commercial):

Base Facility Charge (based on meter size with zero usage)

< 1" meter	$ 11.44
1" meter	$ 28.60
1 1/2" meter	$ 57.20
2" meter	$ 91.52

Usage Charge, per 1,000 gallons	$ 3.36

Availability Rate: (Monthly)

Applicable only to property owners in Fairfield Harbour Service Area	$ 3.28

Connection Charge:

Treasure Cove Subdivision	$ 0.00
North Hills Subdivision	$ 100.00
Glen Arbor/North Bend Subdivision	$ 0.00
Register Place Estates	$ 500.00

Fairfield Harbor: [1/]

All Areas Except Harbor Pointe II Subdivision

Recoupment of capital fees per tap	$ 335.00
Connection charge per tap	$ 140.00

Harbor Pointe Subdivision and any area where mains have been installed after July 24, 1989

Recoupment of capital fee per tap	$ 650.00
Connection charge per tap	$ 320.00

Bradfield Farms:

Connection charge per tap	None
Meter Testing Fee: [2/]	$ 20.00
New Water Customer Charge:	$ 27.00

Reconnection Charge: [3/]

If water service is cut off by utility for good cause	$ 27.00
If water service is discontinued at customer's request	$ 27.00
New Meter Charge:	Actual Cost
Irrigation Meter Installation:	Actual Cost

SEWER RATES AND CHARGES

Monthly Sewer Service:

Residential:

Flat Rate, per dwelling unit	$ 41.40
Bulk Flat Rate, per REU	$ 40.40

Commercial and Other:

Monthly Flat Rate (Customers who do not take water service)	$ 41.40

APPENDIX A-4
PAGE 3 OF 5

Monthly Metered Rates
(based on meter size with zero usage)

<1" meter	$ 11.12
1 1/2" meter	$ 55.60
2" meter	$ 88.96
Usage Charge, per 1,000 gallons	$ 6.20

Bulk Sewer Service for Hawthorne at the Green Apartments: [4/]

Bulk Flat Rate, per REU $ 40.40 per month

(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)

Applicable only to property owners in Fairfield Harbour Service Area $ 2.65

Connection Charge:

Fairfield Harbour: [1/]

All Areas Except Harbor Pointe II Subdivision

Recoupment of capital fees per tap	$ 735.00
Connection charge per tap	$ 140.00

Harbor Pointe Subdivision and any area where mains have been installed after July 24, 1989

Recoupment of capital fee per tap	$ 2,215.00
Connection charge per tap	$ 310.00

Bradfield Farms:

Connection charge per tap None

New Sewer Customer Charge: [5/] $ 27.00

WATER AND SEWER – RATE INCREASE

Reconnection Charge: [6/]

If sewer service is cut off by utility for good cause	Actual Cost

MISCELLANEOUS UTILITY MATTERS

Charge for processing NSF Checks:	$ 25.00
Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Billing Frequency:	Bills shall be monthly for service in arrears. Availability billings semiannually in advance.
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Notes:

[1/] The recoupment of capital portion of the connection charges shall be due and payable at such time as the main water and sewer lines are installed in front of each lot, and the connection charge 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 soon as the certificate of occupancy is issued for that apartment building.

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[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 the customer with the 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 356, on this the 8th day of November, 2017.

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
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

Subdivision	CC	PMF
Sherwood Forest	$ 950.00	$ 0.00
Ski Country	$ 100.00	$ 0.00
White Oak Plantation	$ 0.00	$ 0.00
Wildlife Bay	$ 870.00	$ 0.00
Willowbrook	$ 0.00	$ 0.00
Winston Plantation	$1,100.00	$ 0.00
Winston Pointe, Phase 1A	$ 500.00	$ 0.00
Wolf Laurel	$ 925.00	$ 0.00
Woodrun	$ 0.00	$ 0.00
Woodside Falls	$ 500.00	$ 0.00

Other Connection Fees:

The following connection fees apply unless specified differently by contract approved and/or filed with the North Carolina Utilities Commission.

Amber Acres, Amber Acres North, Amber Ridge, Ashley Hills North, Bishop Pointe, Carriage Manor, Country Crossing, Covington Cross, Heather Glen, Hidden Hollow, Jordan Woods, Lindsey Point, Neuse Woods, Oakes Plantation, Randsdell Forest, Rutledge Landing, Sandy Trails, Stewart's Ridge, Tuckahoe, Wilder's Village, and Forest Hill Subdivisions

WATER AND SEWER – RATE INCREASE

Connection Charge:

A. 5/8" meter	$ 500.00
B. All other meter sizes	Actual cost of meter and installation

The systems where other connection fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows.

Subdivision	CC
Lindsey Point Subdivision	$ 0.00
Amber Acres North, Sections II & IV	$ 570.00
Fairfield Mountain/Apple Valley (a.k.a. Rumbling Bald) Service Area	$ 500.00
Highland Shores Subdivision	$ 500.00
Laurel Mountain Estates	$ 0.00
Carolina Trace	$ 605.00
Connestee Falls	$ 600.00

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 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 connection charge for water and sewer shall be payable upon request by the owner of each lot to be connected to the water and sewer lines. With written consent of the company, payment of the recoupment capital portion of the connection charge may be made payable over five-year period following the installation of the water and sewer mains in front of each lot, payment to be made in such a manner and in such installments as agreed upon between lot owner and the company, together with interest on the balance of the unpaid recoupment of capital fee from said time until payment in full at the rate of 6% per annum.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 356, on this the 8th day of November, 2017.

APPENDIX B-2
PAGE 1 OF 3

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

SCHEDULE OF CONNECTION FEES FOR

SEWER 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	$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

WATER AND SEWER – RATE INCREASE

Brandywine Bay	$ 100.00	$1,456.00
Camp Morehead by the Sea	$ 100.00	$1,456.00
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
White Oak Plantation	$ 0.00	$ 0.00
Willowbrook	$ 0.00	$ 0.00

Subdivision	CC	PMF
Willowbrook (Phase 3)	$ 0.00	$ 0.00
Winston pointe (Phase 1A)	$2,000.00	$ 0.00
Woodside Falls	$ 0.00	$ 0.00

Other Connection Fees:

The systems where other connection fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows:

Subdivision

Carolina Pines

Residential	$1,350.00 per unit (including single-family homes, condominiums, apartments, and mobile homes)
Hotels	$750.00 per unit
Non-residential	$3.57 per gallon of daily design of discharge or $900.00 per unit, whichever is greater

WATER AND SEWER – RATE INCREASE

Subdivision	CC
Fairfield Mountain/Apple Valley (a.k.a. Rumbling Bald)	
Service Area	$ 550.00
Highland Shores	$ 550.00
Carolina Trace	$ 533.00
Connestee Falls	$ 400.00

The following connection fees apply unless specified differently by contract approved and/or filed with the North Carolina Utilities Commission.

All Areas Except Holly Forest XIV, Holly Forest XV, Deer Run, and Lonesome Valley Phases I and II

Recoupment of Capital Fee (RCF) [2/]	$ 0.00
Connection Charge	$ 550.00

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 connection charge for water and sewer shall be payable upon request by the owner of each lot to be connected to the water and sewer lines. With written consent of the company, payment of the recoupment capital portion of the connection charge may be made payable over five-year period following the installation of the water and sewer mains in front of each lot, payment to be made in such a manner and in such installments as agreed upon between lot owner and the company, together with interest on the balance of the unpaid recoupment of capital fee from said time until payment in full at the rate of 6% per annum.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 356, on this the 8th day of November, 2017.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-354, SUB 356

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Carolina Water Service, Inc. of North Carolina, 4944 Parkway Plaza Boulevard, Suite 375, Charlotte, North Carolina 28217, for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All of its Service Areas in North Carolina, Except Corolla Light and Monteray Shores Service Area and Elk River Development	)	**NOTICE TO CUSTOMERS**

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Carolina Water Service, Inc. of North Carolina (CWSNC) to increase rates for water and sewer utility service in all of its service areas in North Carolina (excluding Corolla Light and Monteray Shores Service Area and Elk River Development). The new approved rates are as follows:

WATER RATES AND CHARGES

(Excluding Corolla Light and Monteray Shores Service Area, Elk River Development, Fairfield Harbour Service Area, Treasure Cove, Register Place Estates, North Hills and Glen Arbor/North Bend Subdivisions, Bradfield Farms, Larkhaven Subdivision, Silverton and Woodland Farms Subdivisions and Hawthorne at the Green Apartments

Uniform Water Customers:

Monthly Metered Service (Residential and Commercial):

Base Facility Charge (based on meter size with zero usage)

< 1" meter	$ 24.44
1" meter	$ 61.10
1 1/2" meter	$ 122.20
2" meter	$ 195:52
3" meter	$ 366.60

4" meter	$ 611.00
6" meter	$1,222.00

Usage Charge:

A. Treated Water, per 1,000 gallons	$ 7.70
B. Untreated Water, per 1,000 gallons (Brandywine Bay Irrigation Water)	$ 4.11

C. Purchased Water for Resale, per 1,000 gallons:

Service Area	Bulk Provider	
Carolina Forest	Montgomery County	$ 3.19
High Vista Estates	City of Hendersonville	$ 3.25
Riverpointe	Charlotte Water	$ 6.30
Whispering Pines	Town of Southern Pines	$ 2.23
White Oak Plantation/ Lee Forest	Johnston County	$ 2.28
Winston Plantation	Johnston County	$ 2.28
Winston Point	Johnston County	$ 2.28
Woodrun	Montgomery County	$ 3.19
Yorktown	City of Winston-Salem	$ 5.01
Zemosa Acres	City of Concord	$ 5.27
Carolina Trace	City of Sanford	$ 2.21

Monthly Flat Rate Service: (Billed in Arrears) $ 47.45

Availability Rate: (Semiannual)

Applicable only to property owners in Carolina Forest and Woodrun Subdivisions in Montgomery County $ 24.65

Availability Rate: (Monthly)

Applicable only to property owners in Linville Ridge Subdivision $ 12.35

Availability Rate: (Monthly)

Applicable only to property owners in Fairfield Sapphire Valley Service Area $ 9.10

WATER AND SEWER – RATE INCREASE

Availability Rate: (Monthly)

Applicable only to property owners in Connestee Falls	$ 4.80
Meter Testing Fee:	$ 20.00
New Water Customer Charge:	$ 27.00
Reconnection Charge:	
If water service is cut off by utility for good cause	$ 27.00
If water service is discontinued at customer's request	$ 27.00

SEWER RATES AND CHARGES

(Excluding Corolla Light and Monteray Shores Service Area, Elk River Development, Fairfield Harbour Service Area, Treasure Cove, Register Place Estates, North Hills and Glen Arbor/North Bend Subdivisions, Bradfield Farms, Larkhaven Subdivision, Silverton and Woodland Farms Subdivisions and Hawthorne at the Green Apartments

Uniform Sewer Customers:

Monthly Metered Service:

Base Facility Charge:

Residential (zero usage)	$ 45.97
Commercial (based on meter size with zero usage)	
< 1" meter	$ 45.97
1" meter	$ 114.93
1 1/2" meter	$ 229.85
2" meter	$ 367.76
3" meter	$ 689.55
4" meter	$1,149.25
6" meter	$2,298.50
Usage Charge, per 1,000 gallons	$ 3.11

WATER AND SEWER – RATE INCREASE

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Monthly Metered Purchased Sewer Service:

Collection Charge (Residential and Commercial/SFE)	$	36.75

Usage Charge, per 1,000 gallons based on purchased water consumption

Service Area	Bulk Provider		
White Oak Plantation/ Lee Forest/Winston Pt.	Johnston County	$	4.82
Kings Grant	Two Rivers Utilities	$	3.80
College Park	Town of Dallas	$	5.70

Monthly Flat Rate Service:	$	56.57
Multi-residential customers who are served by a master meter shall be charged the flat rate per unit.	$	56.57

Mt. Carmel Subdivision Service Area:

Monthly Base Facility Charge	$	6.77
Monthly Collection Charge (Residential and Commercial/SFE)	$	36.75
Usage Charge, per 1,000 gallons based on purchased water consumption	$	5.88

Regalwood and White Oak Estates Subdivision Service Areas:

Monthly Flat Rate Sewer Service

Residential Service	$ 56.57
White Oak High School	$1,770.10
Child Castle Daycare	$ 219.90
Pantry	$ 116.80

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Fairfield Mountain/Apple Valley (a.k.a. Rumbling Bald) Service Area and Highland Shores Subdivision

Monthly Sewer Rates:

Residential:	
Collection charge/dwelling unit	$ 36.75
Treatment charge/dwelling unit	$ 69.50
Total monthly flat rate/dwelling unit	$ 106.25
Commercial and Other:	
Minimum monthly collection and treatment charge	$ 106.25
Monthly collection and treatment charge for customers who do not take water service (per SFE)	$ 106.25
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

Availability Rate: (Monthly)

Applicable only to property owners in Fairfield Sapphire Valley Service Area	$ 8.30

Availability Rate: (Monthly)

Applicable only to property owners in Connestee Falls	$ 4.70

New Sewer Customer Charge: $ 27.00

Reconnection Charge:

If sewer service is cut off by utility for good cause	Actual Cost

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RATE ADJUSTMENT MECHANISM:

The Commission-authorized water and sewer system improvement charge (WSIC/SSIC) rate adjustment mechanism continues in effect and will now be applicable to all customers in CWSNC's North Carolina service areas. It has been reset at zero in the Docket No. W-354, Sub 356 rate case proceeding, but CWSNC may, under the Rules and Regulations of the Commission, next apply for a rate surcharge on February 1, 2018, to become effective April 1, 2018. 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 356".

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of November, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-354, SUB 356

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Carolina Water Service, Inc.	)	**NOTICE TO CUSTOMERS**
of North Carolina, 4944 Parkway Plaza	)	**IN TREASURE COVE, REGISTER**
Boulevard, Suite 375, Charlotte, North Carolina	)	**PLACE ESTATES, NORTH HILLS,**
28217, for Authority to Adjust and Increase	)	**AND GLEN ARBOR/NORTH BEND**
Rates for Water and Sewer Utility Service in All	)	**SUBDIVISIONS,FAIRFIELD**
of its Service Areas in North Carolina, Except	)	**HARBOUR SERVICE AREA,**
Corolla Light and Monteray Shores Service	)	**BRADFIELD FARMS**
Area and Elk River Development	)	**SUBDIVISION, LARKHAVEN**
	)	**SUBDIVISION, 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 Subdivision, Larkhaven Subdivision, Silverton and Woodland Farms Subdivisions and Hawthorne at the Green Apartments:

WATER RATES AND CHARGES

<u>Monthly Metered Water Service (Residential and Commercial)</u>:

Base Facility Charge (based on meter size with zero usage)

< 1" meter	$ 11.44
1" meter	$ 28.60
1 1/2" meter	$ 57.20
2" meter	$ 91.52

Usage Charge, per 1,000 gallons	$ 3.36

WATER AND SEWER – RATE INCREASE

Water Availability Rate: (Monthly)

Applicable only to property owners in Fairfield Harbour Service Area	$ 3.28

SEWER RATES AND CHARGES

Monthly Sewer Service:

Residential:

Flat Rate, per dwelling unit	$ 41.40
Bulk Flat Rate, per REU	$ 40.40

Commercial and Other:

Monthly Flat Rate (Customers who do not take water service)	$ 41.40
Monthly Metered Rates (based on meter size with zero usage)	
<1" meter	$ 11.12
1 1/2" meter	$ 55.60
2" meter	$ 88.96
Usage Charge, per 1,000 gallons	$ 6.20

Bulk Sewer Service for Hawthorne at the Green Apartments:

Bulk Flat Rate, per REU	$ 40.40

Sewer Availability Rate: (Monthly)

Applicable only to property owners in Fairfield Harbour Service Area	$ 2.65

APPENDIX C-2
PAGE 3 OF 3

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 356 rate case proceeding, but CWSNC may, under the Rules and Regulations of the Commission, next apply for a rate surcharge on February 1, 2018, to become effective April 1, 2018. 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 356".

ISSUED BY ORDER OF THE COMMISSION.
This the __8th__ day of ____November____, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, 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-354, Sub 356, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ___________________, 2017.

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-354, Sub 356.

Witness my hand and notarial seal, this the ___ day of ___________, 2017.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ___________________________________
Date

WATER AND SEWER – RATE INCREASE

DOCKET NO. W-1077, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Hawksnest Utilities, Inc., 2058 Skyland Drive, Seven Devils, North Carolina 28604, for Authority to Increase Rates for Sewer Utility Service in Hanging Rock Villas and Ski Hawksnest Resort in Watauga County, North Carolina	))))))	ORDER GRANTING PARTIAL RATE INCREASE, FINDING VIOLATION, IMPOSING PENALTY, AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On March 18, 2015, Hawksnest Utilities, Inc. (Hawksnest or Company), filed an application with the Commission seeking authority to increase the rate for providing sewer utility service from $720 per month to $1,200 per month to Hanging Rock Villas, which is a single commercial customer consisting of 24 condominium units. Subsequently, on April 10, 2015, Hawksnest amended its application to also include an increase in the rate for providing sewer utility service from $400 per month to $900 per month to its only other customer, Ski Hawksnest Resort (currently known as Hawksnest Snow Tubing & Zip Line Course and referred to by such name hereinafter in this Order). The Company's approved rates at the time of its filing in 2015 had last been established pursuant to the Recommended Order Approving Transfer and Rates issued on November 14, 1996, in Docket No. W-1077, Sub 0.

On April 23, 2015, the Commission issued an Order Establishing General Rate Case, Approving Provisional Rates, and Requiring Customer Notice. Therein, the Commission noted that in the course of the Public Staff's investigation in Docket No. M-100, Sub 138, the Public Staff learned that in January 2011 Hawksnest increased its rates in Hanging Rock Villas pursuant to an agreement with the Hanging Rock Resort Villas Condominium Owners Association but without obtaining Commission approval. Hawksnest's rate increase application and subsequent amendment were filed at the Public Staff's request. The Company has requested the Commission approve the rate increase for service in Hanging Rock Villas retroactive to January 2011. The Public Staff recommended that Hawksnest be allowed to charge the proposed rates on a provisional basis pending the outcome of the rate case investigation, at which time amounts collected from Hanging Rock Villas or Hawksnest Snow Tubing & Zip Line Course that are ultimately determined by the Commission to have been excessive will be subject to refund.

The Notice to Customers attached to the Order stated that the matter may be decided without a public hearing if no significant protests were received by customers within 45 days of the date of such notice. The provisional rates approved by the Commission were the same as the Company's proposed rates. By letter filed on March 22, 2016, Hawksnest requested that the Commission rescind or waive the customer notice requirement in the April 23, 2015 Order and accept in its place the March 11, 2016 notarized statement of the President of the Hanging Rock Resort Villas Condominium Owners Association agreeing to the proposed rate increase. By letter also filed on March 22, 2016, the Public Staff stated that it supported the Company's request. As a result of the Company's filing of the notarized statement indicating agreement to the rate increase, the notice requirement became unnecessary.

WATER AND SEWER – RATE INCREASE

On April 1, 2016, the Public Staff filed a Proposed Order which was accompanied by the affidavits of Calvin C. Craig, III, Financial Analyst, Economic Research Division and Charles M. Junis, Utilities Engineer, Water and Sewer Division; and the affidavit and exhibit of Iris Morgan, Staff Accountant, Accounting Division. The sworn affidavit of witness Junis indicated that the Company has agreed with the Public Staff's recommendations.

On December 20, 2016, in Docket Nos. W-1077, Sub 1 and M-100, Sub 138, the Commission issued an Order Approving Tariff Revision and Requiring Customer Notice. Such tariff revision, required by Section 2.4.(a) of Session Law 2015-6 (House Bill 41), which became effective January 1, 2017, was necessary in order to reflect the January 1, 2017 reduction in the State corporate income tax from 4% to 3%, pursuant to Session Law 2013-316 (House Bill 998).

On August 31, 2017, Mr. Bill Ferguson, President of the Hanging Rock Resort Villas Condominium Owners Association filed a letter with the Commission indicating that it waives its right to any refunds related to the difference between the rate approved by the Commission ($720 per month) and the rate agreed upon by Hawknest and the Hanging Rock Resort Villas Condominium Owners Association ($1,200 per month) for the period beginning January 2011 and continuing through the date the provisional rate of $1,200 per month was approved by the Commission by Order issued April 23, 2015, in this docket.

Based upon the verified application, the affidavits of the Public Staff, and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. Hawksnest is a public utility authorized to provide sewer utility service to Hanging Rock Villas and Hawksnest Snow Tubing & Zip Line Course, in Watauga County, North Carolina.

2. Hawksnest is properly before the Commission, pursuant to Chapter 62-133 of the General Statutes of North Carolina, seeking approval of an increase in its monthly rates for sewer utility service for its two commercial customers Hanging Rock Villas (consisting of 24 condominium units) and Hawksnest Snow Tubing & Zip Line Course. Hawksnest and Hawksnest Snow Tubing & Zip Line Course are under common ownership.

3. The test period established for this proceeding is the 12 months ended December 31, 2014.

4. Pursuant to the Recommended Order Approving Transfer and Rates issued in Docket No. W-1077, Sub 0, on November 14, 1996, which became effective and final on December 3, 1996, the following monthly flat sewer rates were approved for Hawksnest:

	Approved Rate
Monthly Flat Rate Sewer Service:	
Hawksnest Snow Tubing & Zip Line Course	$400
Hanging Rock Villas	$720

5. In January 2011, Hawksnest increased its monthly flat sewer rate from $720 to $1,200 in Hanging Rock Villas pursuant to an agreement with the Hanging Rock Resort Villas Condominium Owners Association but without obtaining Commission approval.

6. Hawksnest's approved, present (partially not approved by the Commission), and proposed rates are as follows:

	Approved Rates	Present Rates	Proposed Rates
Monthly Flat Rate Sewer Service:			
Hawksnest Snow Tubing & Zip Line Course	$400	$ 400	$ 900
Hanging Rock Villas	$720	$1,200[1]	$1,200

The Company has not proposed any other changes to its rates.

7. In its Order Establishing General Rate Case, Approving Provisional Rates, and Requiring Customer Notice issued on April 23, 2015, in this docket, the Commission approved the Company's proposed rates on a provisional basis pending the outcome of the rate case investigation, subject to refund of any amounts determined by the Commission to be excessive.

8. The quality of service provided by Hawksnest is adequate.

9. Hawksnest's annual service revenues at its presently approved rates (the rates established by the Commission in Docket No. W-1077, Sub 0) are $13,440[2] and at its provisional and proposed rates are $25,200.

10. The Company requested an increase in rates that would produce $11,760 in additional service revenues.

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[1] The present rate charged by Hawksnest to Hanging Rock Villas was not approved by the Commission.

[2] The annual service revenues actually charged by Hawksnest using the unapproved, negotiated sewer rate with Hanging Rock Villas of $1,200 per month and the Commission-approved monthly rate of $400 for Hawksnest Snow Tubing & Zip Line Course, was $19,200, beginning with calendar year 2011 and continuing until the Commission approved provisional rates by Order issued April 23, 2015 in the present docket.

WATER AND SEWER – RATE INCREASE

11. The level of test period operating revenue deductions after all the Public Staff's adjustments (excluding regulatory fee and income taxes) is $20,531.

12. The appropriate level of depreciation expense to include in this proceeding is $373.

13. For purposes of this proceeding, regulatory fees were calculated based upon the statutory rate of 0.148 %, which was the rate in effect at the time the Public Staff filed its affidavits.

14. The original cost rate base for use in this proceeding, after all the Public Staff's adjustments, is $4,377, consisting of sewer plant in service of $9,827, less accumulated depreciation of $7,926 and average tax accruals of $35, plus cash working capital of $2,511.

15. Pursuant to G.S. 62-133.1, the operating ratio method, which allows a margin on operating revenue deductions requiring a return, is the appropriate method for determining Hawksnest's revenue requirement in this proceeding.

16. A margin of 7.50% on total operating deductions requiring a return is just and reasonable for use in this proceeding.

17. A 7.50% margin on total operating revenue deductions requiring a return produces an operating ratio of 93.14% including taxes and 93.02% excluding taxes.

18. The total annual revenues necessary to allow the Company the opportunity to earn a return on expenses of 7.50% found to be just and reasonable is $22,451 in sewer service revenues. This annual revenue requirement results in an increase of $9,011 or 67% over total annual service revenues produced by existing rates of $13,440.

19. The following rates, as recommended by the Public Staff, will produce $22,451 in annual service revenues and will allow Hawksnest a reasonable opportunity to earn the authorized margin:

	Recommended Rates
Monthly Flat Rate Sewer Service:	
Hawksnest Snow Tubing & Zip Line Course	$ 671
Hanging Rock Villas	$1,200

20. Hawksnest and Hanging Rock Villas were in agreement with the Public Staff's recommended rates. The agreed-upon rates are just and reasonable and should be approved, subject to an adjustment to reflect the reduction in the State corporate income tax rate effective January 1, 2017.

21. Pursuant to Section 2.4.(a) of Session Law 2015-6 (House Bill 41), Hawksnest rates were adjusted effective January 1, 2017, in Docket Nos. W-1077, Sub 1 and M-100, Sub 138, to reflect the reduction in the State corporate income tax rate from 4% to 3%, which became effective

January 1, 2017, pursuant to Session Law 2013-316 (House Bill 998). Prior to such rate adjustment, Hawksnest was charging provisional rates pending the outcome of this rate case proceeding.

22. On December 20, 2016, in Docket Nos. W-1077, Sub 1 and M-100, Sub 138, the Commission issued an Order Approving Tariff Revision and Requiring Customer Notice which approved the following provisional rates effective January 1, 2017:

	Present Rates
Monthly Flat Rate Sewer Service:	
Hawksnest Snow Tubing & Zip Line Course	$ 670.46
Hanging Rock Villas	$1,199.04

These rates are the rates recommended by the Public Staff in its Proposed Order and Affidavits filed April 1, 2016, in this proceeding; and they are further reduced by 0.08% to reflect the decrease in the State corporate income tax rate effective January 1, 2017, as proposed by the Public Staff in its filing[1] on November 21, 2016, in the tax docket, Docket No. M-100, Sub 138.

23. Pursuant to the Commission's Order Decreasing Regulatory Fee Effective July 1, 2016, issued on July 11, 2016, in Docket No. M-100, Sub 142, the regulatory fee rate was decreased from 0.148% to 0.14%, effective July 1, 2016. The reduction in the annual revenue requirement as a result of this decrease in the regulatory fee rate is not significant enough to decrease the monthly flat rates approved herein. The regulatory fee rate did not change on July 1, 2017, for fiscal year ended June 30, 2018, but remained at 0.14%.

24. The provisional rates approved for Hawksnest on December 20, 2016, in Docket Nos. W-1077, Sub 1 and M-100, Sub 138, which reflect the rates recommended by the Public Staff in this proceeding and agreed to by the Company, and reduced to reflect the decrease in the State corporate income tax rate effective January 1, 2017, are just and reasonable and should be approved. The provisional rate for Hanging Rock Villas was $1,200 per month and the approved rate herein is $1,199.04; no refund should be required. Furthermore, as recommended by the Public Staff, no refund of the difference between the provisional rate of $900 per month and the rate approved herein of $670.46 for Hawksnest Snow Tubing & Zip Line Course should be required, given the common ownership of the two entities, Hawksnest and Hawksnest Snow Tubing & Zip Line Course.

25. Hawksnest should be required to post a $10,000 bond and acceptable surety with the Commission for providing sewer utility service to Hanging Rock Villas and Hawksnest Snow Tubing & Zip Line Course.

[1] Public Staff Exhibit 3, Page 40 of 71, Appendix A, attached to the November 21, 2016 filing by the Public Staff in Docket No. M-100, Sub 138.

26. Hawksnest violated the provisions of G.S. 62-139 when it increased its monthly flat sewer rate from $720 to $1,200 in Hanging Rock Villas in January 2011 pursuant to an agreement with the Hanging Rock Resort Villas Condominium Owners Association without obtaining prior Commission approval to modify its Commission-established rates.

27. A monetary penalty of $2,500 should be assessed to Hawksnest for violating the provisions of G.S. 62-139; such penalty is warranted and appropriate in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 THROUGH 7

The evidence for these findings of fact is contained in the application, in the affidavits of Public Staff witnesses Morgan and Junis, and in the Commission's records. This evidence is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding of fact is contained in the application, in the Commission's records, and in the affidavit of Public Staff witness Junis. This evidence is uncontroverted.

Public Staff witness Junis stated that Hanging Rock Villas and Hawksnest Snow Tubing & Zip Line Course are the only two customers of the Company and that Hawksnest and Hawksnest Snow Tubing & Zip Line Course are under common ownership. Witness Junis commented that Hanging Rock Villas consists of 24 condominium units.

Witness Junis averred that he has reviewed the files for the sewer system and corresponded with George Smith of the North Carolina Department of Environmental Quality, Division of Water Resources (DWR), regarding the operation of the sewer system. Witness Junis stated that Mr. Smith, an Environmental Senior Specialist, conducted a Compliance Evaluation Inspection on September 15, 2015, and classified the results as satisfactory with respect to the permit NC0058891.

Based upon his review of the files, witness Junis observed that Mr. Smith had noted that to access the facility persons must traverse a steep embankment and that trees located near the plant present issues such as an overabundance of shade that may inhibit the treatment process, debris falling on and in the plant, and the potential for a tree to fall onto the plant and severely damage or destroy the operations.

Witness Junis described the wastewater system as consisting of a 0.01 million gallons per day wastewater collection, treatment, and extended aeration discharge facilities. Witness Junis determined that, according to the permit, the wastewater treatment facilities consist of an influent holding tank, bar screen, aeration basin, clarifier with sludge return, aerated sludge holding tank, tablet chlorinator with chlorine contact chamber, de-chlorination, re-aeration chamber, and flow meter. He commented that the effluent discharges into Valley Creek, part of the Watauga River Basin.

Witness Junis inspected the system on October 6, 2015. He observed that the discharge facility was inaccessible due to recent rain events. He maintained that the collection and treatment facilities appeared to be in fair condition and operating properly. Witness Junis reiterated Mr. Smith's concerns, primarily focusing on the trees and the importance of preventive capital improvements related to safety such as grates, steps, and railings.

Witness Junis concluded that based upon a lack of customer protest and the Public Staff's review of the wastewater system and information pertaining to the wastewater system, Hawksnest is providing adequate service to its customers.

Based upon the foregoing, the Commission finds and concludes that the quality of service provided by Hawksnest is adequate. However, the Commission finds and concludes that Hawksnest should address, to the extent it has not already done so, the concerns expressed by DWR and witness Junis, as noted herein concerning the operation of the plant, and should consider various preventive measures related to DWR's and the Public Staff's identified operational and safety concerns.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 9 THROUGH 14

The evidence supporting these findings of fact is contained in the application, in the affidavits of Public Staff witnesses Junis and Morgan, and in the Commission's records. The Company did not take issue with the Public Staff's position on these issues.

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

The evidence for these findings of fact is contained in the affidavit of Public Staff witness Craig. The Company has agreed with all of the Public Staff's recommendations.

Public Staff analyst Craig recommended using the operating ratio method pursuant to G.S. 62-133.1(a), which allows the Commission to fix rates for water and sewer utilities using a margin on operating revenue deductions requiring a return, for determining the proper revenue requirement in this proceeding. The Company did not oppose the use of the operating ratio method for determining the overall fair rate of return in this proceeding.

The Commission has carefully considered the foregoing evidence and concludes that the operating ratio methodology as described in G.S. 62-133.1(a) is reasonable for use in this proceeding.

Analyst Craig recommended that the Company should be granted a 7.50% margin on expenses. His recommendation produces operating ratios of 93.14% (including taxes) and 93.02% (excluding taxes). Analyst Craig indicated that he derived a margin above expenses by combining the risk-free rate for U.S. Treasury bonds (averaged over a representative period) with a 3.0 percentage point factor to adjust for risk. He stated that his estimate of the risk-free rate is 4.50%, which when combined with the 3.0% risk factor produces the 7.50% margin.

Analyst Craig maintained that, as outlined in Docket No. W-173, Sub 14, a general rate case application by Montclair Water Company, several factors should be considered when judging the adequacy of a return. He stated that these factors include interest coverage, adequacy of the income level after interest expense, the level of inflation, and the quality of service. Analyst Craig commented that in this proceeding he had not incorporated any consideration with respect to quality of service. He contended that interest coverage has been provided at an adequate level and that the level of inflation has been factored into the U.S. Treasury bond rate by investor expectations of the future level of inflation. Analyst Craig asserted that his recommended margin on expenses provides an adequate level of income after interest expense. For these reasons, Analyst Craig recommended that Hawksnest should be granted a 7.50% margin on expenses. The Company has agreed with all of the Public Staff's recommendations.

Based upon the foregoing, the Commission finds and concludes that a 7.50% margin on operating expenses, as recommended by the Public Staff and agreed to by the Company, is appropriate in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18 THROUGH 24

The evidence for these findings of fact is contained in the application, in the affidavits of Public Staff witnesses Junis and Morgan, and in the Commission's records.

In its Order Establishing General Rate Case, Approving Provisional Rates, and Requiring Customer Notice issued on April 23, 2015, the Commission approved the Company's proposed rates on a provisional basis pending the outcome of the rate case investigation, subject to refund of any amounts determined by the Commission to have been excessive. Hawksnest did not propose any other changes in its rates other than the monthly flat rates for sewer utility service for its two commercial customers, which are its only customers.

Based upon the annual service revenue requirement of $22,451 recommended by Public Staff witness Morgan, Public Staff witness Junis recommended a monthly flat sewer rate of $1,200 for Hanging Rock Villas and $671 for Hawksnest Snow Tubing & Zip Line Course. Witness Junis indicated that Hawksnest has agreed with the Public Staff's recommendations.

Concerning the Public Staff's recommended monthly flat sewer rate of $1,200 for Hanging Rock Villas, witness Junis maintained that Hanging Rock Villas uses a significantly higher volume of water than Hawksnest Snow Tubing & Zip Line Course. As a result, witness Junis contended that Hanging Rock Villas is responsible for the majority of the wastewater that is treated by the wastewater treatment plant and should bear the cost of that treatment. Moreover, witness Junis stated that, according to Mr. Sam Shannon, Property Manager of Hanging Rock Villas, the Condominium Owners Association Board approved the proposed sewer rate of $1,200 per month before it was implemented by Hawksnest in January 2011.

With respect to the matter that the provisional rates being charged by Hawksnest are subject to refund of any amounts ultimately determined by the Commission to have been excessive, Public Staff witness Morgan maintained that since Hawksnest Snow Tubing & Zip Line Course and Hawksnest are under common ownership, any excessive amounts would apply only to

Hanging Rock Villas. Witness Morgan also contended that since witness Junis has recommended approval of the provisional rate presently being charged to Hanging Rock Villas, that there should be no refund of the provisional rate required. Furthermore, witness Morgan opined that since the present rate charged to Hanging Rock Villas is justified, even with no gross receipts tax and a State income tax rate of 4%, and the Hanging Rock Villas has agreed to this rate, the Public Staff also recommends that no refunds related to the tax rate changes be made in Docket No. M-100, Sub 138.

Based upon the foregoing, the Commission finds and concludes that no amount of the provisional rate charged to Hanging Rock Villas would be considered excessive; consequently, no refund is required. Further, the Commission finds and concludes that no refund of the difference between the provisional rate of $900 per month and the recommended rate of $671 per month for sewer utility service to Hawksnest Snow Tubing & Zip Line Course should be required, given the common ownership of the two entities, Hawksnest and Hawksnest Snow Tubing & Zip Line Course.

With respect to the monthly flat sewer rates recommended by the Public Staff and agreed to by Hawksnest in this proceeding, the Commission observes that such rates, adjusted to reflect the decrease in the State corporate income tax rate from 4% to 3% which became effective January 1, 2017, were implemented on a provisional basis effective January 1, 2017, pursuant to Commission Order issued December 20, 2016, in Docket Nos. W-1077, Sub 1 and M-100, Sub 138. Based upon the foregoing findings and the entire record in this proceeding, the Commission finds and concludes that the recommended provisional monthly rates ($1,199.04 for Hanging Rock Villas and $670.46 for Hawksnest Snow Tubing & Zip Line Course), reflected in the Schedule of Rates, attached hereto as Appendix A, are just and reasonable and, therefore, are approved as permanent rates.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence for this finding of fact is contained in the Commission's records, the North Carolina General Statutes, and the Commission's Rules and Regulations.

Upon a review of the history of this docket, the Commission has determined that Hawknest has not posted a bond for providing sewer utility service to Hanging Rock Villas and Hawksnest Snow Tubing & Zip Line Course.

On April 2, 1996, in Docket No. W-1077, Sub 0, Hawknest filed an application with the Commission to transfer the franchise to provide sewer utility service in Hanging Rock Villas and Ski Hawknest Resort (now known as Hawksnest Snow Tubing & Zip Line Course) from Kent and Kent Partnership (Docket No. W-1009) and for approval of rates. In its application, Hawksnest requested Temporary Operating Authority and approval of interim rates.

On August 1, 1996, in Docket No. W-1077, Sub 0, the Commission issued an Order Requiring Bond, Establishing General Rate Case, Suspending Rates, Scheduling Hearing, and Requiring Customer Notice. In its Order, the Commission noted that the Public Staff indicated no objections to the Commission granting Temporary Operating Authority to Hawksnest but recommended that Hawksnest be required to post a bond of $10,000 prior to approval of

Temporary Operating Authority. The Commission acknowledged that "[t]he Applicant assumed control and ownership of the sewage treatment and collection facilities from Kent and Kent Partnership in November 1994, and has acted in the capacity of the utility and charged rates since that time." The Commission concluded that Temporary Operating Authority should be granted to Hawksnest subsequent to the receipt of a bond in the amount of $10,000.

An order granting temporary authority was not ever issued by the Commission in Docket No. W-1077, Sub 0. In his affidavit, Public Staff Utilities Engineer Jack Floyd stated that although no bond has been posted and no Temporary Operating Authority has been granted, the Public Staff recommends that the requirement for posting a bond remain in effect and that the bond must be received prior to granting any transfer.

On November 14, 1996, a Recommended Order Approving Transfer and Rates was issued. At that time, no bond had been posted by Hawksnest. Further, the Recommended Order did not require that Hawksnest post a bond by a future date.

The Commission observes that with respect to bonding requirements for water and sewer companies, G.S. 62-110.3 states, in pertinent part, that "[n]o franchise may be granted to any water or sewer utility company until the applicant furnishes a bond, secured with sufficient surety as approved by the Commission, in an amount not less than ten thousand dollars ($10,000)". The Commission is of the opinion that the $10,000 bond recommended by the Public Staff in the transfer application proceeding discussed herein should be required from Hawksnest in this proceeding in order to comply with the bonding requirements established by G.S. 62-110.3. Consequently, the Commission finds and concludes that Hawksnest should be required to post a $10,000 bond and acceptable surety with the Commission within 45 days after the issuance of this Order for providing sewer utility service to Hanging Rock Villas and Hawksnest Snow Tubing & Zip Line Course.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26 AND 27

The evidence for these findings of fact is contained in the application, in the affidavits of Public Staff witnesses Junis and Morgan, and in the Commission's records.

As previously noted hereinabove, in January 2011, Hawksnest increased its monthly flat sewer rate from $720 to $1,200 in Hanging Rock Villas pursuant to an agreement with the Hanging Rock Resort Villas Condominium Owners Association but without obtaining Commission approval. Mr. Lenny Cottom, Vice President of Hawksnest, stated in a letter included with the Company's application that the Commission-approved sewer rate of $720 per month was "the same since we took over the utility plant in 1995". Mr. Cottom explained that "[s]ince the rate did not change for over 15 years and our costs were not even covered by this rate, an agreement between Hawksnest Utilities and the POA of Hanging Rock Villas was reached to increase the rate to [sic] $1200 a month starting in January 2011". In his letter, Mr. Cottom further admitted that "[t]he proper course of action to petition for a rate change to the Utility Commission was not done". Moreover, he acknowledged that "[t]his was a complete mistake on my part and I apologize for the oversight."

Based upon the evidence presented in this proceeding, the Commission acknowledges that an agreement was reached between Hawksnest and the Hanging Rock Resort Villas Condominium Owners Association prior to the sewer rate being increased in January 2011 from $720 per month to $1,200 per month. In particular, Mr. Cottom stated in the Company's application that an agreement had been reached and Public Staff witness Junis testified that, according to Mr. Sam Shannon, Property Manager of Hanging Rock Villas, the Condominium Owners Association Board approved the proposed sewer rate of $1,200 per month before it was implemented by Hawksnest in January 2011. Moreover, in a notarized statement dated March 11, 2016, by Mr. Bill Ferguson, President of the Hanging Rock Resort Villas Condominium Owners Association, filed with the Commission on March 22, 2016, he stated that the Hanging Rock Resort Villas Condominium Owners Association "is in agreement with the rate of $1200 per month for sewer service to Hanging Rock Villas as proposed by Hawksnest Utilities and previously approved by the Utilities Commission on a provisional basis".

Furthermore, after consultation with the Public Staff, Mr. Ferguson, on behalf of the Hanging Rock Resort Villas Condominium Owners Association, filed a notarized statement with the Commission on August 31, 2017, indicating that it waives its right to any refunds related to the difference between the rate approved by the Commission ($720 per month) and the rate agreed upon by Hawknest and the Hanging Rock Villas Condominium Owners Association ($1,200 per month) for the period beginning January 2011 and continuing through the date the provisional rate of $1,200 per month was first approved by the Commission by Order issued April 23, 2015, in this docket.

Notwithstanding the aforementioned agreement between the Company and the customer, the verified waiver by the customer of any refunds related to the agreed-upon rate effective January 2011, and the fact that the Public Staff did not recommend the Commission require a refund of the unauthorized increase, the Commission cannot overlook the fact that Hawksnest violated the provisions of G.S. 62-139 when it increased its monthly sewer rate from $720 to $1,200 in Hanging Rock Villas, one of its two customers, in January 2011 without first seeking and obtaining Commission approval to do so. Such violation, which occurred over a period of approximately four years and three months, resulted in the collection by Hawksnest of approximately $24,480 in unauthorized revenues.

The Commission observes that G.S. 62-139(a) provides that

> No public utility shall directly or indirectly, by any device whatsoever, charge, demand, collect or receive from any person a greater or less compensation for any service rendered or to be rendered by such public utility than that prescribed by the Commission, nor shall any person receive or accept any service from a public utility for a compensation greater or less than prescribed by the Commission.

Further, the Commission notes that G.S. 62-310(a) provides, in pertinent part, that

> Any public utility which violates any of the provisions of this Chapter or refuses to conform to or obey any rule, order or regulation of the Commission shall, in addition to the other penalties prescribed in this Chapter forfeit and pay a sum up

> to one thousand dollars ($1,000) for each offense, to be recovered in an action to be instituted in the Superior Court of Wake County, in the name of the State of North Carolina on the relation of the Utilities Commission; and each day such public utility continues to violate any provision of this Chapter or continues to refuse to obey or perform any rule, order or regulation prescribed by the Commission shall be a separate offense.

As previously noted, Hawksnest's offense resulted in the collection of approximately $24,480 in unauthorized revenues and such offense occurred over a period of four years and three months. The Commission acknowledges that, pursuant to G.S. 62-310(a), such violation by Hawksnest could result in a financially detrimental penalty being assessed by the Commission. In particular, the Commission could require Hawksnest to refund to Hanging Rock Villas the entire amount of revenues that was collected without Commission approval, plus interest. However, due to the unique circumstances of this case as discussed herein, between Hawksnest and its customer, Hanging Rock Villas, the Commission has concluded that such refund should not be required. The Commission could also impose a penalty of up to $1,000 "for each offense" as allowed pursuant to G.S. 62-310; such penalty would be substantial considering that the duration of the violation was approximately 51 months and each month the customer was unlawfully billed would be considered a separate offense which could result in a possible penalty of up to $51,000.

After careful consideration of these unique circumstances, the Commission is of the opinion that an assessment of some amount of monetary penalty is warranted and appropriate in this proceeding. In recognizing the seriousness of the violation that has occurred, the Commission is assessing a meaningful penalty for such violation to hopefully make Hawksnest assiduously attentive to the existing North Carolina General Statutes and the Commission's Rules and Regulations related to the regulation of a franchised public utility that must be followed as the Company continues to make future business decisions and manage its utility operations in North Carolina. Accordingly, in consideration of Hawksnest's adjusted test year level of operating revenues and expenses, its annual net income, rate base, and overall financial position, the Commission finds and concludes that due to the Company's violation of G.S. 62-139(a), a monetary penalty in the amount of $2,500 is just and reasonable based on the specific facts and circumstances in this proceeding.

Furthermore, Hawksnest should begin to pay to the Commission the monetary penalty assessed herein of $2,500, in four equal installments, with the first payment due not later than 45 days after the date of this Order. If Hawksnest does not voluntarily pay the penalty of $2,500, the Commission Staff is hereby directed to recover said penalty of $2,500 in an action instituted in the Superior Court of Wake County pursuant to G.S. 62-310.

However, should Hawksnest desire to contest the assessment of this penalty or the monetary amount of the penalty, Hawksnest may file a motion with the Commission within 30 days of the issuance date of this Order requesting that the Commission schedule a hearing for Hawksnest to present its evidence concerning this issue.

IT IS, THEREFORE, ORDERED as follows:

1. That the following documents filed in this docket are hereby received as evidence in this proceeding: the application filed on March 18, 2015; the amendment to the application filed on April 10, 2015; the March 22, 2016 filing by the Public Staff containing a letter from Mr. Lenny Cottom on behalf of Hawksnest and a notarized statement from Mr. Bill Ferguson, one of the Company's two customers; the affidavits of Calvin C. Craig, III, Financial Analyst, Economic Research Division and Charles M. Junis, Utilities Engineer, Water and Sewer Division, and the affidavit and exhibit of Iris Morgan, Staff Accountant, Accounting Division filed by the Public Staff on April 1, 2016; and the letter from Mr. Bill Ferguson filed on August 31, 2017.

2. That Hawksnest Utilities, Inc., is authorized to increase its rates for providing sewer utility service to Hanging Rock Villas and Hawksnest Snow Tubing & Zip Line Course in Watauga County, North Carolina. Consequently, the provisional Schedule of Rates approved on December 20, 2016, in Docket Nos. W-1077, Sub 1 and M-100, Sub 138, and attached hereto as Appendix A, is hereby approved as the permanent rates and deemed to be filed with the Commission pursuant to G.S. 62-138.

3. That Hawksnest shall not be required to make any refunds of the provisional rates approved by Commission Order issued April 23, 2015, in this proceeding or the increased rate charged to Hanging Rock Villas effective January 2011, for the reasons set forth herein.

4. That a copy of this Order shall be mailed or hand delivered to the Hanging Rock Resort Villas Condominium Owners Association within 10 days of the date of this Order, and that the attached Certificate of Service, properly signed and notarized, shall be submitted to the Commission not later than 20 days after the date of this Order.

5. That Hawksnest shall address, to the extent it has not already done so, the concerns expressed by DWR and witness Junis, as noted herein, concerning the operation of the plant, and shall consider various preventive measures related to DWR's and the Public Staff's identified operational and safety concerns.

6. That Hawksnest shall post a $10,000 bond and acceptable surety with the Commission for providing sewer utility service to Hanging Rock Villas and Hawksnest Snow Tubing & Zip Line Course. Hawksnest shall complete one of the attached bonds (Appendices A-1, A-2, or A-3) and <u>return said bond to the Commission</u> within 45 days of the issuance date of this Order. Additionally:

a. If the bond selected is Appendix A-1, the Applicant shall deposit the appropriate surety in the amount of $10,000 with the bank of its choice, after prior consultation with Commission Fiscal Director Pat Jeter at 919-733-0832.

b. If the bond selected is Appendix A-2, the Applicant shall file the letter of credit surety and commitment letter (see Filing Requirements for Bonding, Appendix A-4) with the Commission. The letter of credit shall contain the following language <u>verbatim</u>:

"If for any reason the Letter of Credit is not to be renewed upon its expiration, the Bank shall, at least 60 days prior to the expiration date of the Letter of Credit, provide written notification by means of certified mail, return receipt requested, to the Chief Clerk of the North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4325, that the Letter of Credit will not be renewed beyond the then current maturity date for an additional period. Failure to renew the Letter of Credit shall, without the necessity of the Commission being required to hold a hearing or appoint an emergency operator, allow the Commission to convert the Letter of Credit to cash and deposit said cash proceeds with the administrator of the Commission's bonding program. Said cash proceeds from the converted Letter of Credit shall be used to post a cash bond on behalf of the Principal pursuant to North Carolina Utilities Commission Rules R7-37(e) and/or R10-24(e)."

c. If the bond selected is Appendix A-3, the Applicant shall file the power of attorney and commitment letter (see Filing Requirements for Bonding, Appendix A-4) with the Commission.

7. That Hawksnest shall pay a monetary penalty in the amount of $2,500 for its violation of G.S. 62-139(a). Should Hawksnest desire to contest the assessment of such penalty or the monetary amount of the penalty, Hawksnest shall file a motion with the Commission within 30 days of the issuance date of this Order requesting that the Commission schedule a hearing for Hawksnest to present its evidence concerning this issue. Otherwise, this penalty shall be paid to the Commission in four equal monthly installment payments of $625, due on the first Wednesday of each month with the first monthly payment due on Wednesday, November 1, 2017. Such payment shall be made payable to "N.C. Department of Commerce/Utilities Commission" and mailed to the Chief Clerk's Office of the North Carolina Utilities Commission. If Hawksnest does not voluntarily pay the penalty of $2,500, the Commission Staff is hereby directed to recover said penalty of $2,500 in an action instituted in the Superior Court of Wake County pursuant to G.S. 62-310.

8. That the Chief Clerk shall serve a copy of this Order on Hawksnest by United States Certified Mail, return receipt requested.

ISSUED BY ORDER OF THE COMMISSON.
This the 26th day of September, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

Commissioner ToNola D. Brown-Bland did not participate in this decision.

APPENDIX A

SCHEDULE OF RATES

for

HAWKSNEST UTILITIES, INC.

for providing sewer utility service in

Watauga County, North Carolina

Monthly Flat Rate Sewer Service:

Hawksnest Snow Tubing & Zip Line Course	$ 670.46
Hanging Rock Villas	$1,199.04

Tap Fee:

Sewer	$ 200.00

Reconnection Charge:

If sewer service cut off by utility for good cause	$ 14.99
If sewer service discontinued at customer's request	$ 14.99

Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Billing Frequency:	Shall be monthly in advance
Finance Charge For Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.
Returned Check Charge:	$ 14.99

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1077, Sub 2, on this the 26th day of September, 2017.

NCUC DOCKET NO. W-1077, SUB 2 APPENDIX A-1

BOND

______________________________ of ______________________________,
(Name of Utility) (City)

______________________________, as Principal, is bound to the State of North
(State)
Carolina in the sum of ______________________________

______________________________ Dollars ($____________) and for which payment to be made, the Principal by this bond binds himself, his, and its successors and assigns.

THE CONDITION OF THIS BOND IS:

WHEREAS, the Principal is or intends to become a public utility subject to the laws of the State of North Carolina and the rules and regulations of the North Carolina Utilities Commission, relating to the operation of a water or sewer utility ______________________________

____
(describe utility)
______________________________ and,

WHEREAS, North Carolina General Statutes § 62-110.3 requires the holder of a franchise for water or sewer service to furnish a bond with sufficient surety, as approved by the Commission, conditioned as prescribed in G.S. § 62-110.3, and Commission Rules R7-37 and/or R10-24, and,

WHEREAS, the Principal has delivered to the Commission ______________________________

____
(description of security)

with an endorsement as required by the Commission, and,

WHEREAS, the appointment of an emergency operator, either by the Superior Court in accordance with G.S. § 62-118(b) or by the Commission with the consent of the owner, shall operate to forfeit this bond, and

WHEREAS, this bond shall become effective on the date executed by the Principal, and shall continue from year to year unless the obligations of the Principal under this bond are expressly released by the Commission in writing.

NOW THEREFORE, the Principal consents to the conditions of this Bond and agrees to be bound by them.

This the ____________ day of ____________________ 20___.

____
(Name)

NCUC DOCKET NO. W-1077, SUB 2 APPENDIX A-2

BOND

______________________________ of ______________________________,
(Name of Utility) (City)
______________________________, as Principal, is bound to the State of North
(State)
Carolina in the sum of ______________________________
______________ Dollars ($______________) and for which payment to be made, the Principal by this bond binds ______________ and ______________ successors and assigns.
(himself)(itself) (his)(its)

THE CONDITION OF THIS BOND IS:

WHEREAS, the Principal is or intends to become a public utility subject to the laws of the State of North Carolina and the rules and regulations of the North Carolina Utilities Commission, relating to the operation of a water and/or sewer utility ______________
____
(describe utility)
______________________________ and,

WHEREAS, North Carolina General Statutes § 62-110.3 requires the holder of a franchise for water and/or sewer service to furnish a bond with sufficient surety, as approved by the Commission, conditioned as prescribed in G.S. § 62-110.3, and Commission Rules R7-37 and/or R10-24, and

WHEREAS, the Principal has delivered to the Commission an Irrevocable Letter of Credit from
____
(Name of Bank)

with an endorsement as required by the Commission, and,

WHEREAS, the appointment of an emergency operator, either by the Superior Court in accordance with G.S. § 62-118(b) or by the Commission with the consent of the owner, shall operate to forfeit this bond, and

WHEREAS, if for any reason, the Irrevocable Letter of Credit is not to be renewed upon its expiration, the Bank shall, at least 60 days prior to the expiration date of the Irrevocable Letter of Credit, provide written notification by means of certified mail, return receipt requested, to the Chief Clerk of the North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4325, that the Irrevocable Letter of Credit will not be renewed beyond the then current maturity date for an additional period, and

WHEREAS, failure to renew the Irrevocable Letter of Credit shall, without the necessity of the Commission being required to hold a hearing or appoint an emergency operator, allow the

Commission to convert the Irrevocable Letter of Credit to cash and deposit said cash proceeds with the administrator of the Commission's bonding program, and

WHEREAS, said cash proceeds from the converted Irrevocable Letter of Credit shall be used to post a cash bond on behalf of the Principal pursuant to North Carolina Utilities Commission Rules R7-37(e) and/or R10-24(e), and

WHEREAS, this bond shall become effective on the date executed by the Principal, and shall continue from year to year unless the obligations of the Principal under this bond are expressly released by the Commission in writing.

NOW THEREFORE, the Principal consents to the conditions of this Bond and agrees to be bound by them.

This the ____________ day of ____________________ 20___.

____
(Principal)

BY: ________________________________

NCUC DOCKET NO. W-1077, SUB 2 APPENDIX A-3

BOND

_____________________ of ___________________, ___________________________,
(Name of Utility) (City) (State)
as Principal, and ______________________________, a corporation created and existing under
(Name of Surety)
the laws of ________________________________, as Surety (hereinafter called "Surety"), are
(State)
bound to the State of North Carolina in the sum of _______________ Dollars ($_________)
and for which payment to be made, the Principal and Surety by this bond bind themselves and their successors and assigns.

THE CONDITION OF THIS BOND IS:

WHEREAS, the Principal is or intends to become a public utility subject to the laws of the State of North Carolina and the rules and regulations of the North Carolina Utilities Commission, relating to the operation of a water and/or sewer utility _____________
____
(Describe utility)
____ and,

WHEREAS, North Carolina General Statutes § 62-110.3 requires the holder of a franchise for water and/or sewer service to furnish a bond with sufficient surety, as approved by the

Commission, conditioned as prescribed in § 62-110.3, and Commission Rules R7-37 and/or R10-24, and

WHEREAS, the Principal and Surety have delivered to the Commission a Surety Bond with an endorsement as required by the Commission, and

WHEREAS, the appointment of an emergency operator, either by the Superior Court in accordance with G.S. § 62-118(b) or by the Commission with the consent of the owner, shall operate to forfeit this bond, and

WHEREAS, if for any reason, the Surety Bond is not to be renewed upon its expiration, the Surety shall, at least 60 days prior to the expiration date of the Surety Bond, provide written notification by means of certified mail, return receipt requested, to the Chief Clerk of the North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4325, that the Surety Bond will not be renewed beyond the then current maturity date for an additional period, and

WHEREAS, failure to renew the Surety Bond shall, without the necessity of the Commission being required to hold a hearing or appoint an emergency operator, allow the Commission to convert the Surety Bond to cash and deposit said cash proceeds with the administrator of the Commission's bonding program, and

WHEREAS, said cash proceeds from the converted Surety Bond shall be used to post a cash bond on behalf of the Principal pursuant to North Carolina Utilities Commission Rules R7-37(e) and/or R10-24(e), and

WHEREAS, this bond shall become effective on the date executed by the Principal, for an initial ____________ year term, and shall be automatically renewed for additional ____________
(No. of Years) (No. of Years)
year terms, unless the obligations of the principal under this bond are expressly released by the Commission in writing.

NOW, THEREFORE, the Principal and Surety consent to the conditions of this bond and agree to be bound by them.

This the ______________ day of ____________________________ 20____.

____
(Principal)
BY: __________________________________

____
(Corporate Surety)
BY: __________________________________

WATER AND SEWER – RATE INCREASE

APPENDIX A-4

<u>Filing Requirements for Bonding</u>
Type of Bond

	Cash / Certificate of Deposit Bond	Irrevocable Letter of Credit Bond	Commercial Surety Bond
Bond A-1	X 1/		
Bond A-2		X 1/	
Bond A-3			X 1/
Cash / CD	X 2/		
Letter of Credit		X 3/	
Power of Attorney			X 4/
Commitment Letter		X 5/	X 5/

(To be filed with the Chief Clerk - where applicable)

1/ Original Copy of the Bond - Bond forms are usually attached to Order Requiring Bond for each specific franchise.

2/ Notification of deposit from the bank that cash or Certificate of Deposit surety has been received for a given bond.

3/ Original Copy of Non-Perpetual Irrevocable Letter of Credit [Letter of Credit must comply with Rule R7-37 New Section (e)(4) as adopted by the Commission in its Order dated July 19, 1994, In Docket No. W-100, Sub 5.]

4/ Original Copy of Power of Attorney for individual who signed Appendix A-3 as Corporate Surety

5/ Original Copy of <u>Commitment Letter</u>

(a) This letter need only contain a statement indicating whether the utility is required to pledge utility company assets (collateral and type) to secure the bond or irrevocable letter of credit; and

(b) The premium paid by the utility (if any) to the bank and/or lending institution for their accommodation of the borrower.

WATER AND SEWER – RATE INCREASE

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers a copy of the Order issued by the North Carolina Utilities Commission in Docket No. W-1077, Sub 2, and such Order was mailed or hand delivered by the date specified in the Order.

This the _____ day of __________________ 2017.

By: ______________________________
Signature

____
Name of Utility Company

The above named Applicant, ______________________________, personally appeared before me this day and, being first duly sworn, says that the required copy of the Commission Order was mailed or hand delivered to all affected customers, as required by the Commission Order dated ________________ in Docket No. W-1077, Sub 2.

Witness my hand and notarial seal, this the _____ day of _____________ 2017.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ______________________________
Date

DOCKET NO. W-1305, SUB 3

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Pluris Hampstead, LLC for Authority to Pledge Utility Assets Pursuant to G.S. 62-160 to Secure Loan	) ORDER APPROVING) PLEDGE OF ASSETS) TO SECURE LOAN

BY THE COMMISSION: On May 16, 2017, Pluris Hampstead, LLC (Pluris or Company) filed an Application pursuant to G.S. 62-160 and Commission Rule R1-16 requesting permission to pledge utility assets to secure a loan in the amount of $3,557,524.

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. Pluris Hampstead, LLC is a limited liability company duly organized and existing under the laws of the State of North Carolina. Pluris is a public utility engaged in the business of providing wastewater treatment service in Pender County pursuant to the Certificate of Public Convenience and Necessity issued to it by the Commission in Docket No. W-1305, Sub 0 on November 5, 2015, and the special use permit issued to Pluris by Pender County on December 24, 2013.

2. By its Application, Pluris petitions the Commission for permission to execute a security agreement and thereby pledge utility assets to secure the loan described herein. The sole purpose of the loan transaction described in the Application is to allow the Company to convert short-term construction financing to longer term/permanent financing for the membrane bioreactor (MBR) wastewater treatment plant that Pluris built in Hampstead, and the associated 11.5-mile force main running north along US 17 to serve that region of Pender County.

3. In order to fund construction of its MBR wastewater treatment plant and regional wastewater treatment system, Pluris borrowed $3,557,524 on a short-term basis through a construction credit line from Frost Bank. The construction credit line was utilized from July 2015 to June 2016, after Pluris funded its equity portion of that project. This short-term loan matures on June 3, 2017, and Frost Bank is working with Pluris Hampstead to convert this credit line to permanent debt.

4. The loan from Frost Bank will be secured through a Security Agreement which will provide the lender with a first lien deed of trust on real estate and first priority security interest and UCC lien on personal property, in form and substance satisfactory to the lender, covering all utility plant, both real and personal property of Pluris, and a first priority assignment of all Pluris' rights, title and interest in and to all accounts receivables, current and future leases, rents and profits relating to the Company's property. Pluris Holdings, LLC will provide a guarantee as to the loan agreement.

5. As of April 30, 2017, Pluris provided wastewater utility service to a total of 166 customers, consisting of 133 residential flat-rate customers and 33 metered commercial customers.

6. Pursuant to Rule R1-16, Pluris provided information, both in its Application and in Confidential Exhibits Pluris 1 and Pluris 2, in support of its request for Commission approval of the arrangements described in the Application.

7. Pursuant to G.S. 62-160 and Commission Rule R1-16, Pluris asserts that the conversion of this construction financing to permanent financing, and the pledge of utility assets to secure such financing, (i) is for a lawful object within the corporate purposes of the Company as a public utility, (ii) is compatible with the public interest, (iii) is appropriate for or consistent with the public performance by Pluris of its service to the public, (iv) will not impair Pluris' ability to perform that service, and (v) is reasonably necessary and appropriate for the purposes for which the said asset pledge would be issued.

WHEREUPON, the Commission now reaches the following

CONCLUSIONS

Based upon the foregoing Findings of Fact and the entire record in this proceeding, the Commission is of the opinion and so finds and concludes that the financing transaction proposed and described in the Application and herein

(i) Are for lawful objects within the corporate purposes of the Company as a public utility;

(ii) Are compatible with the public interest;

(iii) Are necessary, appropriate 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 utility service; and

(v) Are reasonably necessary and appropriate for the purposes for which issued.

IT IS, THEREFORE, ORDERED that Pluris Hampstead, LLC is hereby authorized, empowered and permitted to implement and execute the proposed financing plan and pledging of assets in accordance with the terms thereof as set forth in the Application and exhibits appended thereto, including execution and delivery of loan documents, a security agreement and other documentation as necessary to close this loan and pledge assets to secure it.

IT IS FURTHER ORDERED that the Commission's approval in this Docket does not restrict the Commission's regulatory authority to review and adjust, if the Commission deems it appropriate to do so, the Company's cost of capital and/or expense levels for ratemaking purposes in the Company's next general rate case.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of May, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. W-1317, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Recommendation of Penalty by the	)	
N.C. Underground Damage Prevention	)	
Review Board against Jason Pittman	)	ORDER IMPOSING PENALTY
for Violation of the Underground Utility	)	
Safety and Damage Prevention Act	)	

BY THE COMMISSION: On April 28, 2017, the Underground Damage Prevention Review Board (the Board) notified the Commission that the Board made a final determination in the above-captioned proceeding, recommending that a penalty be assessed against Jason Pittman of A&A Trenching for a violation of the provisions of Chapter 87, Article 8A of the General Statutes, the Underground Utility Safety and Damage Prevention Act. The Board recommends that Mr. Pittman be required to complete training and education. The Board further states that it notified Mr. Pittman of its determination and that the time period for Mr. Pittman to request a hearing before the Board has expired. Pursuant to G.S. 87-129(b1), the Commission issues this order imposing the Board's recommended penalty.

IT IS, THEREFORE, ORDERED as follows:

1. That upon the recommendation of the N.C. Underground Damage Prevention Review Board, Jason Pittman of A&A Trenching shall be, and hereby is, required to complete training and education;

2. That the Chief Clerk of the Commission shall deliver a copy of this order to Jason Pittman of A&A Trenching with an explanation of the right to appeal provided in G.S. 87-129, attached hereto as Attachment A; and

3. That Jason Pittman of A&A Trenching shall, within thirty days of the date of this order, file with the Commission either a notice of appeal or evidence of completion of the required training and education.

ISSUED BY ORDER OF THE COMMISSION.
This the _____24th__ day of August, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

Attachment A

Explanation of Right to Appeal under G.S. 87-129.

Pursuant to the foregoing Order Imposing Penalty, the North Carolina Underground Damage Prevention Review Board (the Board) determined that you violated one or more provisions of the Underground Utility Safety and Damage Prevention Act (the Act) and recommended that a penalty be assessed against you.

You have the right to appeal the Board's determination by initiating an arbitration proceeding within 30 days of the date of this Order. If you elect to initiate an arbitration proceeding, you must file a written request in the docket assigned to your case and pay a filing fee of $250.00 to the Utilities Commission at the following address:

M. Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4300

When the Utilities Commission receives your written request and the $250.00 filing fee, the Utilities Commission will direct the parties to the dispute to select an arbitrator. An arbitrator is a neutral third party selected by the parties to resolve the dispute. The parties are responsible for selecting and contracting with the arbitrator. Upon completion of the arbitration process, the arbitrator will deliver a report to the Utilities Commission and the Utilities Commission will enter an order encompassing the outcome of the arbitration process, including a determination of fault, a penalty, and assessing the costs of arbitration to the non-prevailing party.

DOCKET NO. W-218, SUB 478

In the Matter of		
Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511 - Request for Mandatory Restrictions of Non-Essential Water Use in the Crescent Ridge and Stonehenge Water System Service Areas in Wake County, North Carolina	)	ORDER REQUIRING NOTICE AND GRANTING AUTHORITY TO IMPOSE MANDATORY RESTRICTIONS ON NON-ESSENTIAL WATER USE WITHIN THE STONEHENGE MASTER WATER SYSTEM SERVICE AREA

BY THE COMMISSION: On September 29, 2017, Aqua North Carolina, Inc. (Aqua or Company) filed a Motion requesting the Commission to enter an Order imposing restrictions on non-essential water use applicable to the Company's Stonehenge master water system in Wake County, North Carolina for an indefinite curtailment period for so long as such water-use restrictions remain necessary.

Aqua's Stonehenge master water system serves approximately 735 customers in a service area comprised of the Stonehenge, Wildwood Green, and Still Water Landing Subdivisions in Wake County, North Carolina.

In its Motion, Aqua requested the following specific mandatory water-use restrictions:

- No spray irrigation.
- Handheld use of a container or hose to water flowers, shrubs, trees, and vegetable gardens is allowable on any day (8 p.m. to 8 a.m.).
- No car washing.
- No filling of swimming pools – no topping-off pools.

Aqua also asked that the above-requested mandatory water-use restrictions remain in place indefinitely until lifted or rescinded by the Commission.

Aqua requested that the Commission authorize the Company, after giving notice as required by the Commission, to disconnect the water service of any customer who violates the Commission-ordered mandatory water-use restrictions.

Prior to Aqua filing its motion to impose mandatory water-use restrictions, the following occurred:

1. On or about September 24, 2017, Aqua personnel noticed significant decreased pressure in the elevated storage tank and increased run times on the wells serving the Stonehenge water system along with a notable volume of water pressure calls from customers served by the

Crescent Ridge[1] water system. The Company found no apparent system leaks, but noted that the wells in these systems were unable to keep up with significant system demand for water usage. Because the wells were being taxed, customers experienced low or no water pressure, or discolored water, in both of these systems.

2. Affected customers in the Stonehenge and Crescent Ridge service areas were contacted by Aqua at approximately 6:15 p.m. on Tuesday, September 26, 2017 – either by telephone recording, email, or text messages – notifying them of the water volume situation and requesting that they voluntarily curtail non-essential water usage, including irrigation. Aqua's messages requested that if customers must irrigate:

> … please do so between the hours of 10 p.m. and 4 a.m. and reduce the duration to alternating days. Odd addresses should only irrigate on Tuesdays and Thursdays while even addresses should irrigate Wednesdays and Fridays.

3. In its messages, Aqua acknowledged the hardship this situation was causing its customers and stated that the Company would begin delivering bottled water to the affected communities that afternoon. Delivery of bottled water was initiated on September 27, 2017, and continued until a solution to return adequate water pressure to its customers in these systems was implemented.

4. Aqua surmised that if affected customers voluntarily adhered to the request to curtail water usage, the Company's wells should replenish within one to two days and stated that the Company would notify affected customers once the voluntary curtailment could be lifted and normal water use could be resumed.

5. Subsequently, Aqua came to realize that this situation required more than voluntary water restrictions at the Stonehenge master water system in order to minimize or resolve the problems of low or no water pressure or discolored water being experienced by customers.

6. And on September 28, 2017, temporary water connections to the City of Raleigh were made to ensure increased water pressure to the Stonehenge master water system until the pressure issues are resolved. These connections remain in place and pressure in the systems, for the time being, is adequate.

On September 29, 2017, the Public Staff – North Carolina Utilities Commission (Public Staff) requested that the Commission include Aqua's motion as a supplemental agenda item on Staff Conference, Monday, October 2, 2017.

This matter was presented to the Commission at Staff Conference on October 2, 2017. At that conference, Aqua explained that during the previous week, in its discussions with the North Carolina Department of Environmental Quality (DEQ), Division of Water Resources (DWR), DEQ advised the Company that it needed to be able to act quickly to impose mandatory water-use

[1] In its Motion, Aqua notified the Commission that the Company is continuing to monitor and address the problems affecting the Crescent Ridge water system and will, after further review and evaluation, decide whether it will be necessary to file a separate Motion for Order Restricting Non-Essential Water Use applicable to Crescent Ridge.

restrictions at the highest level (D4 Exceptional Drought level[1]) for an indefinite period of time should the need arise due to changing circumstances concerning the present situation or at another time in the future.

The Public Staff stated at Staff Conference that it agreed with Aqua's motion filed on September 29, 2017, but objected to an indefinite time period for the mandatory water-use restrictions to be in force. The Public Staff contended that a two-week time period for such mandatory water-use restrictions would be appropriate.

A representative from the Attorney General's Office was present at Staff Conference and agreed with the Public Staff's position regarding the Company's motion and the two-week time period limitation for the water-use restrictions to be in force.

Aqua stated that given the present improved level of stability in the Stonehenge master water system due to the temporary connections to the City of Raleigh but also considering the continuing uncertainty of the present situation due to not yet knowing the cause(s) of the system failure, the Company was modifying its Motion. Pursuant to Aqua's modified Motion, the Company requested that the Commission allow Aqua to implement enforceable D4 Exceptional Drought level mandatory water-use restrictions upon certain notice to the Commission, such as 12-hours' notice in advance of Aqua notifying its affected customers. Further, the Company stated that if the Commission could not approve its modified Motion, it requested that the Commission approve its initial Motion as filed on September 29, 2017.

The Public Staff again noted its objection to Aqua's request for discretionary authority to implement mandatory water-use restrictions indefinitely and without obtaining prior Commission approval.

After considering the objections by the Public Staff, Aqua further modified its Motion by requesting that the discretionary authority concerning imposing mandatory water-use restrictions for the Stonehenge master water system be limited to a period of two weeks.

The Public Staff stated that it would not oppose an order of the Commission concerning mandatory water-use restrictions in Stonehenge master water system that would be effective for only a two-week period. The Attorney General did not provide any further comment.

WHEREUPON, the Commission now reaches the following

CONCLUSIONS

Based upon the unique and specific circumstances outlined in Aqua's motion and in the information provided by Aqua and the Public Staff at Staff Conference on October 2, 2017, the Commission finds and concludes that Aqua should be authorized to impose mandatory water-use restrictions within the Stonehenge master water service area (i.e., the Stonehenge, Wildwood Green, and Still Water Landing Subdivisions) until October 18, 2017, without a further order of the Commission; provided, however that Aqua may not impose such restrictions without first

[1] See Commission Order issued May 23, 2008, in Docket Nos. W-100, Sub 46 and WR-100, Sub 6.

providing 12-hours' written notice to the Commission, the Public Staff, and the Attorney General of its intent to do so. Should such notice requirement arise after hours, on the weekend, or on a holiday, Aqua should contact the Chief Counsel of the Commission by telephone at a contact number to be provided to Aqua by the Commission. The Commission may by written order modify or stay Aqua's ability to impose such restrictions for good cause shown prior to the expiration of the notice period. The Commission is of the opinion that due to the nature of the temporary water connections to the City of Raleigh, combined with the currently unknown cause(s) of the system failure, and because of the guidance communicated to the Company by DEQ, an emergency situation could foreseeably arise which would require the imposition of mandatory water restrictions in the Stonehenge master water system. Although an emergency water situation does not currently exist with respect to the Stonehenge master water system due to the temporary water connections to the City of Raleigh, the Commission understands based upon the information provided by Aqua and the Public Staff at Staff Conference that circumstances can change and deteriorate quickly; therefore, Aqua should be granted temporary authority, at its discretion, for this unique and specific circumstance, to impose mandatory water-use restrictions in the Stonehenge master water system. The grant of authority to Aqua shall be in effect for two weeks until October 18, 2017.

With respect to the 12-hours' written notice to the Commission, the Commission finds and concludes that such notice should include a copy of the notification of the imposition of mandatory non-essential water-use restrictions to be provided by Aqua to its customers. Furthermore, such customer notification, if any, should be hand-delivered by Aqua to its customers and such mandatory water-use restrictions, if imposed, should continue through October 18, 2017 unless lifted or rescinded by the Commission, after consultation with Aqua and the Public Staff.

IT IS, THEREFORE, ORDERED, as follows:

1. That upon providing 12-hours' notice to the Commission, the Public Staff, and the Attorney General, Aqua is authorized, in its discretion to impose mandatory water restrictions limiting water usage to essential household use by the customers of Aqua in the Stonehenge master water service area (i.e., the Stonehenge, Wildwood Green, and Still Water Landing Subdivisions) at any time as may be necessary between the date of this Order through Wednesday, October 18, 2017, if Aqua deems such restrictions necessary due to the potential risk of an emergency water situation as described herein.

2. That, under the Commission-authorized non-essential water-use restrictions, the following restrictions shall be in effect <u>if imposed by Aqua by a separate customer notification</u> for as long as Aqua determines a water emergency exists provided that in no circumstance shall such restrictions imposed by Aqua using its temporary Commission-authorized authority extend beyond October 18, 2017, without a further Order of the Commission.

- No spray irrigation.
- Handheld use of a container or hose to water flowers, shrubs, trees, and vegetable gardens is allowable on any day (8 p.m. to 8 a.m.).
- No car washing.
- No filling of swimming pools – no topping-off pools.

3. That if it becomes necessary for Aqua to impose these restrictions on non-essential water use within the Stonehenge master water service area, Aqua shall hand-deliver a written notice to all affected customers clearly stating the specific water restrictions imposed and the effective date of such restrictions. Aqua shall also reference in its written communication to customers that such authority to impose mandatory water-use restrictions was granted to Aqua by the Commission pursuant to this Order.

4. That, should Aqua impose such water restrictions and any affected customer does not comply with such mandatory water-use restrictions, after giving notice as required by the Commission, Aqua is hereby authorized to disconnect the water service of any customer who violates the imposed mandatory water-use restrictions. Specifically, as required by the Commission Order entered in NCUC Docket Nos. W-100, Sub 46 and WR-100, Sub 6 on May 23, 2008, Aqua is allowed to disconnect a water customer if he or she violates the restrictions approved by this Order. However, a customer must be provided a 24-hour notice prior to disconnection (for this purpose a door hanger type notice will be sufficient). The customer will have a full business day after the date of notification to show cause why his or her service should not be disconnected. For purposes of these disconnection procedures, a "business" day does not include weekends or holidays.[1] A customer seeking to show cause why his or her service should not be disconnected should contact the Operations Division of the Commission by telephone at 919-733-3979. If the customer does not successfully show cause, Aqua may disconnect service at the end of the next business day. Aqua must then immediately notify the Commission when it disconnects a customer's service for violation of Commission-authorized non-essential water-usage restrictions.

5. That Aqua shall provide the Commission an update concerning the status of the Stonehenge master water system situation discussed herein and the Company's plans for a permanent solution immediately after Staff Conference, Monday, October 23, 2017.

6. That the conclusions set forth in this Order are based upon the specific and unique circumstances of Aqua's September 29, 2017 motion and the information provided by Aqua and the Public Staff at Staff Conference on October 2, 2017. Such conclusions shall not establish any precedent in future cases.

7. That a copy of this Order shall be mailed with sufficient postage or shall be hand-delivered by Aqua to all customers affected by the possible mandatory non-essential water-use restrictions set forth herein within three days following the date of this Order. Further, Aqua shall submit the attached Certificate of Service to the Commission, properly signed and notarized, within six days of completing such requirement.

[1] A "business" day does not include weekends or holidays. As a result, a Commission-regulated water utility, in this case Aqua, may not disconnect a customer for violating these restrictions on non-essential water usage until after one business day has elapsed after the notice of disconnection has been provided to the affected customer (e.g., if the notice is provided on Tuesday, service may be discontinued on Thursday, or if notice is provided on Saturday, service may be discontinued on Tuesday).

8. That the Chief Clerk shall provide a copy of this Order to the North Carolina Department of Environmental Quality, Division of Water Resources and the Attorney General.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of October, 2017.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

Commissioners Lyons Gray and Daniel G. Clodfelter did not participate in this decision.

CERTIFICATE OF SERVICE

I, ______________________________________, mailed with sufficient postage or hand delivered to all affected customers a copy of the Order issued by the North Carolina Utilities Commission in Docket No. W-218, Sub 478, and such Order was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________ 2017.

By: ______________________________
Signature

____
Name of Utility Company

The above named Applicant, ______________________________, personally appeared before me this day and, being first duly sworn, says that the required copy of the Commission Order was mailed or hand delivered to all affected customers, as required by the Commission Order dated ________________ in Docket No. W-218, Sub 478.

Witness my hand and notarial seal, this the ______ day of _______________ 2017.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires ______________________________
Date

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RESALE OF WATER AND SEWER – Cancellation of Certificate

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RESALE OF WATER AND SEWER – Certificate

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ACG Winston Village, LLC		
(Quail Ridge Mobile Home Park)	WR-2262, SUB 0	(02/21/2017)
AG Cherry Valley, LLC		
(Cherry Valley Mobile Home Park)	WR-2272, SUB 0	(03/14/2017)
Allure Investments, LLC		
(Pleasure Living Mobile HP)	WR-2397, SUB 0	(09/20/2017)
Alston Village Apartments, LLC		
(The Aster Apartments)	WR-2378, SUB 0	(07/31/2017)
Antiquity Residences, LLC		
(Junction at Antiquity Apts.)	WR-2331, SUB 0	(05/16/2017)
Arbor Ridge Property, LLC		
(Arbor Ridge Apartments)	WR-2407, SUB 0	(10/04/2017)
Arboretum, LP; The		
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ARWC – 567 Cutchen Lane, LLC		
(Village at Cliffdale Apartments)	WR-2362, SUB 0	(07/14/2017)
ARWC – 5650 Netherfield Place, LLC		
(Morganton Place Apartments)	WR-2361, SUB 0	(07/14/2017)
Ashbrook Investors, LLC		
(Ashbrook Apartments)	WR-2401, SUB 0	(09/27/2017)
Asheville-Buncombe Educational Housing, LLC		
(Williams Baldwin Teacher Apts.)	WR-2294, SUB 0	(04/04/2017)
Asheville Multifamily Partners, LLC		
(The Views Apartments)	WR-2349, SUB 0	(07/03/2017)
Banner Parkside, LLC		
(Parkside at South Tryon Apts.)	WR-2450, SUB 0	(11/28/2017)
Bellemont Pointe Apartments, LLC		
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Berkeley Apartments, LLC		
(Berkeley Apartments, Phase I)	WR-1985, SUB 2	(03/28/2017)
BH2 – DM Ninth Street Apartments, LLC		
(810 Ninth Street Apartments)	WR-2393, SUB 0	(09/07/2017)

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Bo-Ty, LLC, et al.		
(Copus 1 Indian Trail Apartments)	WR-2293, SUB 0	(03/29/2017)
BR-TBR Lake Boone NC Owner, LLC		
(Leigh House Apartments)	WR-2435, SUB 0	(11/21/2017)
BRC Tall Oaks, LLC		
(Country Park at Tall Oaks Apts.)	WR-2328, SUB 0	(05/23/2017)
Burke; Robert T.		
(High Oaks Estates Mobile HP)	WR-2318, SUB 0	(05/09/2017)
Carolina Square Project, LP		
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CCC Tryon Park at Rivergate, LLC, et al.		
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CCC Westfall Park, LLC		
(Mayfaire Flats Apts., Phase I)	WR-2215, SUB 0	(01/09/2017)
Cedar Grove NC IV, LLC		
(Montclaire Estates Apartments)	WR-2319, SUB 0	(05/09/2017)
CEV Wilmington, LP		
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Charlotte Hills Mobile Home Park, LLC		
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Charlotte Multifamily Partners, LLC		
(Icon on the Greenway Apartments)	WR-2367, SUB 0	(08/21/2017)
Charlotte Northlake Multifamily LeaseCo, LLC		
(Vanguard Northlake Apartments)	WR-2332, SUB 0 WR-2193, SUB 0	(05/08/2017)
Charlotte Owner 2, LLC, et al.		
(Waterford Hills Apartments)	WR-2376, SUB 0	(08/03/2017)
(Matthews Pointe Apartments)	WR-2376, SUB 1	(09/05/2017)
(Mission Matthews Place Apts.)	WR-2376, SUB 2	(09/05/2017)
Chartwell Marshpointe, LLC		
(Concord Apartments)	WR-2354, SUB 0	(07/12/2017)
CHG-MHP Roxboro, LLC		
(Pine View Mobile Home Park)	WR-2437, SUB 0	(11/14/2017)
Collins Estate Jacksonville, NC, LLC		
(Collins Estates Mobile HP)	WR-2274, SUB 0	(02/28/2017)
Conabeer Properties, LLC		
(150 at The Lofts at South at South Slope Apartments)	WR-1659, SUB 2	(01/17/2017)

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(Concord Ridge Apartments)	WR-2335, SUB 0	(06/13/2017)
Crescent NoDa, LLC		
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CRP-GREP Overture Crabtree Owner, LLC		
(Overture Crabtree Apartments)	WR-2449, SUB 0	(11/28/2017)
CRP/WF Gateway Owner, LLC		
(The Mark at Durham One Apts.)	WR-2356, SUB 0	(07/05/2017)
DD Morrison, LLC		
(Sorrel at Morrison Plantation Apts.)	WR-2295, SUB 0	(04/11/2017)
District Asheville, LLC; The		
(The District Apartments)	WR-2440, SUB 0	(12/05/2017)
Eagle Point 2014, LLC		
(Eagle Point Apartments)	WR-2413, SUB 0	(09/27/2017)
EB Somerset, LP		
(Somerset Apartments)	WR-2441, SUB 0	(12/04/2017)
Ebex I, LP		
(Azalea Park Apartments)	WR-2297, SUB 0	(04/04/2017)
ECP Garner Apartments, LLC		
(Flats on 7th Apartments)	WR-2455, SUB 0	(12/12/2017)
Elite Street Capital Ambercrest DE, LP		
(The Fields Parkside Apartments)	WR-2308, SUB 0	(11/28/2017)
Elite Street Capital Ashland DE, LP		
(The Ashland Apartments)	WR-2310, SUB 0	(04/25/2017)
Elite Street Capital Grand Oaks Equity DE, LP		
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Elite Street Capital Meadowood DE, LP		
(The Fields Lakeview Apartments)	WR-2309, SUB 0	(12/04/2017)
Emory Land Company		
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Fisher-Forest Village, Salisbury Square Investment, LLC		
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Florence Street Exchange, LLC		
(Beaucatcher flats Apartments)	WR-2348, SUB 0	(07/05/2017)
Gateway Apartments Charlotte, LLC		
(Centric Gateway Apartments)	WR-2428, SUB 0	(11/07/2017)

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Greens at Tryon, LLC		
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GUGV Poplar Charlotte Property Owning, LP		
(Ascent Uptown Apartments)	WR-2267, SUB 0	(02/15/2017)
Hillandale North, LLC		
(Clairmont at Hillandale North Apts.)	WR-2287, SUB 0	(03/15/2017)
Historic Revolution, LLC		
(Revolution Mill Apartments)	WR-2311, SUB 0	(04/25/2017)
HR-Hunter's Point, LLC		
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Hunter Group, LLC		
(Parkview Terrace Apartments)	WR-2431, SUB 0	(11/07/2017)
Hunters Pointe Apartments NC, LLC		
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Interurban Madison, LLC		
(Madison Hall Apartments)	WR-2286, SUB 0	(03/14/2017)
IPM Services, LLC		
(Magnolia Place Apartments)	WR-2225, SUB 0	(01/04/2017)
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(Millis and Main Apartments)	WR-2382, SUB 0	(08/14/2017)
Lake Wylie MF, LLC		
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Legacy Village Apartments, LLC		
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Liberty Crossing Apartments, LLC		
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Lofts at Charleston Row, LLC; The		
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LWH Edgewater Village Apartments, LP		
(Edgewater Village Apartments)	WR-2343, SUB 0	(06/13/2017)

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Magnolia Grove Apartments, LLC		
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Marquee Station Acquisition, LLC		
(The Village at Marquee Station Apts.)	WR-2390, SUB 0	(08/29/2017)
Marsh Euclid Apartments, LLC		
(The Lexington Dilworth Apartments)	WR-2250, SUB 0	(02/03/2017)
MDO Bridford Lake, LLC		
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MDO Madison, LLC		
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Meadowlark Acres, LLC		
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Meridian at Broad Street Market, LLC		
(Meridian at Broad Street Market Apts.)	WR-2409, SUB 0	(10/10/2017)
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(Post Gateway Place Apartments)	WR-22, SUB 71 WR-1542, SUB 3	(08/31/2017)
Millbrook Estates, LLC		
(Millbrook Apartments)	WR-2419, SUB 0	(10/12/2017)
Modern Way Owner, LLC		
(The Addison at South Tryon Apts.)	WR-2248, SUB 0	(02/03/2017)
Morgan Bond Charlotte, LLC		
(South Park Apartments)	WR-2410, SUB 0	(10/10/2017)
Murchison Apartments, LLC		
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NC 2017 Roxboro, LLC		
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New Woodland Creek, LLC		
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NHE Tract E, LLC		
(Park Central Apartments)	WR-2365, SUB 0	(07/21/2017)
North Elm Investments, LLC		
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Northland Randolph Park Apartments, LLC		
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Pappas Properties Development, LLC		
(Solis Berewick Apartments)	WR-2391, SUB 0	(09/06/2017)
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Park West Village Phase III, LLC		
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Pecan Grove MHP, LLC		
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PGP Willow Woods, LLC		
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Poplar Manor, LLC		
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PSREG Davis Owner, LLC		
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(Dartmouth North Hills Apartments)	WR-2456, SUB 0	(12/18/2017)
RCG Grove Park Apartments, LLC		
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RL MXU I, LLC		
(RL Lofts Apartments)	WR-2269, SUB 0	(02/22/2017)
RRPIII Lakeview Durham Resi, LLC		
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RS Oak Ridge, LLC		
(Park at Oak Ridge Apartments)	WR-2329, SUB 0	(05/23/2017)
Sawmill Point Apartments Owner, LLC		
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SEMF Watercress, LLC		
(Watercrest Apartments)	WR-2244, SUB 0	(01/24/2017)
Signature Burlington, LLC		
(Wayfare at Garden Crossing Apts.)	WR-2351, SUB 0	(06/26/2017)
SK Chapel Hill, LLC		
(Bridges at Chapel Hill Apartments)	WR-2270, SUB 0	(03/07/2017)
SkyHouse Charlotte II, LLC		
(SkyHouse Uptown II Apartments)	WR-2249, SUB 0	(02/03/2017)
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Southline Apartments, LLC		
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Southwood Realty Company		
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Spanish Oaks, LLC		
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SRC Candler, LLC		
(The Haven Apartments)	WR-2337, SUB 0	(05/31/2017)
SRC Charleston Place, LLC		
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St. James Homes, Inc.		
(Asberry Courts Apartments)	WR-2300, SUB 0	(04/04/2017)
Stallings Mill Apartments, LLC		
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(Long Shoals Mobile Home Park)	WR-2408, SUB 0	(10/04/2017)
Ten Ten Apartments, LP		
(Villages at McCullers Walk Apts.)	WR-2411, SUB 0	(10/10/2017)
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(Hampton Forest Apartments)	WR-2219, SUB 0	(01/04/2017)
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Triangle Real Estate Brentwood, LLC		
(Brentwood Chase Apartments)	WR-2253, SUB 0	(02/03/2017)
Triangle Real Estate of Gastonia, Inc.		
(The Palisades at Legacy Oaks Apts.)	WR-1125, SUB 33	(05/16/2017)
Triangle Seasons at Concord, LLC		
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University City Community, LLC		
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Wafra Invest Loft 135, LP		
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(Haven at Research Triangle Park Apartments)	WR-2265, SUB 0	(07/28/2017)
Weaverville Apartments, LLC		
(Hawthorne at Weaverville Apts.)	WR-2374, SUB 0	(08/09/2017)
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(Museum Tower Apartments)	WR-2347, SUB 0	(06/26/2017)
WF-ARK NCMF Apartments, LLC		
(Cadence Music Factory Apartments)	WR-2296, SUB 0	(04/04/2017)
Wheeling Village MHC, LLC		
(Wheeling Village Mobile HC)	WR-2434, SUB 0	(11/21/2017)
Wilkinson Brandemere, LLC		
(Brandemere Apartments)	WR-2396, SUB 0	(09/13/2017)
Wilmington Gallery I, LLC		
(Element Barclay Apartments)	WR-2317, SUB 0	(04/25/2017)
7th Street Progression Partners, LLC		
(The Langston Apartments)	WR-2271, SUB 0	(02/28/2017)
54 Station, LLC		
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180 West Club, LP		
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757 North, LLC		
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Ashbrook Property Holdings, LLC		
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Bel Haven, LLC, d/b/a Bel Haven LLC, MA		
(Belle Haven Apartments)	WR-2389, SUB 0 WR-1822, SUB 4	(08/21/2017)
Bel Vinoy, LLC		
(The Vinoy at Innovation Park Apts.)	WR-2307, SUB 0 WR-1308, SUB 5	(04/12/2017)
Bell Fund VI Meadowmont, LP		
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BR Preston View, LLC		
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(Wesley Village Apartments)	WR-2340, SUB 0 WR-1379, SUB 5	(06/13/2017)
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Camden Summit Partnership, LP		
(Camden Grandview Apartments)	WR-6, SUB 193 WR-547, SUB 7	(11/01/2017)
Cary Greens, LP		
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(Bell Biltmore Park Apartments)	WR-2229, SUB 0 WR-1076, SUB 7	(01/17/2017)
CCW Assets, LLC		
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Cedar Trace Properties, LLC		
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(Cedar Trace IV Apartments)	WR-2394, SUB 1 WR-999, SUB 8	(09/07/2017)
Centennial Plantation Pointe, LLC		
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Chelsea Investments, LLC		
(Dogwood Hills Mobile HP)	WR-2232, SUB 0 WR-1575, SUB 3	(01/11/2017)
CLT Stone Ridge, LLC		
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Crest at Brier Creek Investments SPE, LLC		
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CUSA NC Holdings, LP		
(Camden Gallery Apartments)	WR-2425, SUB 0 WR-1836, SUB 3	(11/01/2017)
CWS Plantation SAF IX, LP, et al.		
(Marquis at Morrison Plantation Apts.)	WR-2260, SUB 0 WR-1599, SUB 2	(02/14/2017)
Durham Realty, Incorporated		
(300 Swift Apartments)	WR-2381, SUB 0 WR-1727, SUB 4	(08/21/2017)
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Environs at East 54, LLC, et al.		
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(Allister North Hills Apartments)	WR-2256, SUB 0 WR-1457, SUB 5	(02/03/2017)
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(Brookford Place Apartments)	WR-2258, SUB 0 WR-614, SUB 9	(02/28/2017)
Ginkgo Salem Ridge, LLC		
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Grand Reserve at Pavilions, LP		
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Grove at Kernersville Apts.; The		
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High Point NC Holdings, LLC		
(Hunters Point Apartments)	WR-2430, SUB 0 WR-2227, SUB 1	(12/11/2017)
HLLC CWS 205, LLC, et al.		
(Marq Midtown 205 Apartments)	WR-2246, SUB 0 WR-1866, SUB 2	(01/24/2017)
HM Mooresville, LLC, et al.		
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Pleasant Garden Apartments, LLC		
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PRCP-Raleigh I, LLC		
(Cedar Springs Apartments)	WR-2392, SUB 0 WR-1158, SUB 5	(09/07/2017)
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(The Hamptons Apartments Homes)	WR-2338, SUB 0 WR-2038, SUB 1	(06/13/2017)
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Rock Creek at Ballantyne Owner, LLC		
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WE Mission Triangle Point, LLC		
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1207 Kelston Place, LP		
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Fairway Apartment Partners, LLC		
(Lexington on the Green Apts.)	WR-2414, SUB 0	(10/09/2017)
Ginkgo Croasdaile, LLC		
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RCG Grove Park Apartments, LLC		
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RCG Skyland, LLC		
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Wilkinson Brandemere, LLC		
(Brandemere Apartments)	WR-2396, SUB 1	(11/01/2017)

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TGM Laurel Ridge, LLC -- WR-2263, SUB 0; Order Granting Certificate of HWCCWA and Full-Capture Authority and Approving Rates *(Laurel Ridge Apartments, Phase II)* (03/09/2017)

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AERC Blakeney, LP		
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AERC Southpoint, LP		
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BMA North Sharon Amity Apts., LLC		
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Bradford I SPE, LLC		
(Bradford Luxury Apts. & Townhomes)	WR-1579, SUB 2	(02/21/2017)
BRC Alexandria Park, LLC		
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BRC Wilmington, LLC		
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BRC Wilson, LLC		
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Brookstown Winston-Salem Apartments, LLC		
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(Camden Crest Apartments)	WR-6, SUB 191	(09/08/2017)
(Camden Overlook Apartments)	WR-6, SUB 192	(09/08/2017)
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CCC Olde Raleigh, LLC		
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CCC One Norman Square, LLC		
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CCC Residences at Biltmore Park, LLC		
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CCC Summerlin Ridge, LLC		
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CCC The Edison, LLC		
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CCC Uptown Gardens, LLC		
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CCC Verde Vista, LLC		
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CCC Villages at Pecan Grove, LLC, et al.		
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CEG Friendly Manor, LLC		
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Centennial Addington Farms, LLC		
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Centennial Highland Creek, LLC		
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Central Pointe Apartments, LLC		
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Chamberlain Place Apartments, LLC		
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(Chamberlain Place Apartments)	WR-819, SUB 7	(11/07/2017)
Chapel Hill Housing, LLC		
(1701 North Apartments)	WR-2107, SUB 1	(03/13/2017)
Charlotte Hills Mobile Home Park, LLC		
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Chason Ridge Apartment Complex Operating Company, LLC		
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Chelsea Investments, LLC		
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Conabeer Properties, LLC		
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Concord-Empire Davis Street, LLC		
(The L Apartments)	WR-1757, SUB 2	(11/06/2017)
Coral Stone, LLC		
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Courtney NC, LLC		
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Courtney Ridge H. E., LLC		
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CPGPI Still Meadow, LLC		
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Crestmont at Ballantyne Apartments, LLC		
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Crowne at Polo Associates, L.P.		
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CSP Community Owner, LLC		
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(Camden Dilworth Apartments)	WR-909, SUB 35	(08/29/2017)
(Camden Governor's Village Apts.)	WR-909, SUB 41	(09/07/2017)
(Camden Lake Pine Apartments)	WR-909, SUB 39	(08/30/2017)
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CSP Hunt's View, LLC		
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Delphil II, LLC		
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Donathan Cary Limited Partnership		
(Hyde Park Apartments)	WR-558, SUB 11	(08/01/2017)
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DPR Westover, LLC		
(Cary Reserve at Weston Apartments)	WR-1989, SUB 1	(11/20/2017)
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Duraleigh Woods LL, LLC		
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Echo Forest, LLC		
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(Avellan Springs Apartments)	WR-1935, SUB 2	(12/19/2017)
Edwards Mill RE II, LLC, et al.		
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(Elan City Center Apartments)	WR-1928, SUB 2	(07/11/2017)
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(The Fields Market Street Apartments)	WR-2310, SUB 1	(12/05/2017)
Elite Street Capital Grand Oaks Equity DE, LP		
(The Fields Archdale Station Apts.)	WR-2315, SUB 1	(11/27/2017)
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ELPF Station Nine, LLC		
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Enclave at Crossroads, LLC		
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(Franklin Woods Apartments)	WR-1105, SUB 2	(03/08/2017)
G Colonial, LLC		
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G Partnership, LP		
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General Greene, LLC		
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Genesis Partners, LLC		
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Ginkgo BVG, LLC		
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Ginkgo Kimmerly, LLC		
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(Crest Gateway Apartments)	WR-1809, SUB 3	(10/03/2017)
Golden Triangle #7 – Commonwealth, LLC		
(The Julien Apartments)	WR-2097, SUB 1	(05/02/2017)
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Grace Park Development, LLC		
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Granite Ridge Investments, LLC		
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Gray Property 2205, LLC		
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GRE JV Wilmington, LLC		
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Greenfield Village NC, LLC		
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Greenville Village, LLC		
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Greenway at Fisher Park, LLC		
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Greenway at Stadium Park, LLC		
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Greystone WW Company, LLC		
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Grove at Kernersville Apartments, LLC; The		
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GS Edinborough Commons, LLC		
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GS Edinborough Park, LLC		
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GS Village, LLC		
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Guardian Tryon Village, LLC		
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GUGV Poplar Charlotte Property Owning, LP		
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Hamilton Florida Partners, LLC		
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Hanover Terrace, LLC		
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Hawthorne-Charleston Strickland, LLC, et al.		
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Hawthorne-Midway Summerwood, LLC		
(Hawthorne at the Hall Apartments)	WR-1194, SUB 7	(11/14/2017)
Hawthorne-Midway Turtle Creek Phase III, LLC, et al.		
(Hawthorne at Southside Apts., Ph. III)	WR-2077, SUB 1	(02/21/2017)
(Hawthorne at Southside Apts., Ph. III)	WR-2077, SUB 3	(09/08/2017)
Hawthorne-Midway Wilmington, LLC		
(Hawthorne at the Station Apts.)	WR-1622, SUB 1	(08/04/2017)
Headwaters at Autumn Hall, LLC		
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Heather Park Apartments (NC) Owner, LLC		
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Heather Ridge Apartments, LLC		
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Heather Ridge Condominiums, LLC		
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Heatherwood Florida Partners, LLC		
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Henson Place, LLC		
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Heritage Andover I, LLC, et al.		
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Heritage Circle Apartments, LLC		
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Heritage Gardens, LLC		
(Ardmore Heritage Apartments)	WR-1533, SUB 3	(08/24/2017)
Heritage Hanover II, LLC, et al.		
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Heritage Osprey II, LLC, et al.		
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(Highland Oaks Apartments)	WR-2066, SUB 2	(11/27/2017)
Highland Park Investors II, LLC, et al.		
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Highland Quarters, LLC		
(Muirfield Village Apartments)	WR-520, SUB 11	(09/06/2017)
Highlands at Olde Raleigh, LLC		
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Hillandale North, LLC		
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Historic Revolution, LLC		
(Revolution Mill Apartments)	WR-2311, SUB 1	(10/16/2017)
HLLC CWS 205, LLC, et al.		
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Holly NC, LLC		
(Holly Hills Apartments)	WR-1290, SUB 6	(07/25/2017)
HRTBH Timber Creek, LLC		
(Timber Creek Apartments)	WR-1761, SUB 3	(10/18/2017)
HTC Preston Reserve, LLC, et al.		
(Bell Preston Reserve Apartments)	WR-1180, SUB 6	(08/31/2017)
Hudson Capital Park Forest, LLC		
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Hudson Capital Steeplechase, LLC		
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Hunt Hill Apartments, LLC		
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I & G Direct Real Estate 41, LP		
(Residence at South Park Apts.)	WR-2025, SUB 2	(09/20/2017)
Inman Park Investment Group, Inc.		
(Inman Park Apartments)	WR-383, SUB 14	(07/14/2017)
Innesbrook Apartments, LLC		
(Southpoint Glen Apartments)	WR-1150, SUB 3	(11/13/2017)
Interurban Wellington, LLP		
(Stadler Place Apartments)	WR-2028, SUB 2	(09/26/2017)

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Ivy Hollow Apartments, LLC		
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Jetton Apartments, LLC		
(The Linden Apartments)	WR-2185, SUB 1	(10/04/2017)
Johnston Road Apartments, LLC		
(Element South Apartments)	WR-1849, SUB 2	(09/08/2017)
Jones; Joe T. & JoAnn		
(Asbury Acres Mobile Home Park)	WR-1677, SUB 3	(09/08/2017)
Junction 1504, LLC		
(Junction 1504 Apartments)	WR-1559, SUB 3	(12/18/2017)
K Colonial, LLC		
(Autumn Trace Apts., Phases 2 & 3)	WR-1943, SUB 4	(07/28/2017)
(Colonial Apartments, Phase 3)	WR-1943, SUB 5	(07/28/2017)
K Partnership, LLC		
(Hampton Downs Apartments)	WR-1631, SUB 3	(07/28/2017)
KC Realty Investments, LLC		
(Woodland Heights Mobile HP)	WR-950, SUB 16	(10/02/2017)
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(Oteen Mobile Home Park)	WR-950, SUB 18	(10/02/2017)
(Rockola Mobile Home Park)	WR-950, SUB 19	(10/02/2017)
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(Cedar Grove Mobile Home Park)	WR-310, SUB 37	(12/11/2017)
(Dogwood Circle Mobile Home Park)	WR-310, SUB 38	(12/11/2017)
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Lake Brandt I, LLC, et al.		
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Lakeshore Apartments, LLC		
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Legacy at Twin Oaks, LLC		
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Legacy at Wakefield/HF, LLC, et al.		
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Legacy Cornelius, LLC		
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Pleasant Garden Apartments, LLC		
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(Eastwood Village Apartments)	WR-1320, SUB 5	(08/30/2017)
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Renphil II, LLC		
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Seagrove Village MHP, LLC		
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Somerstone NC, LLC		
(Somerstone Apartments)	WR-2207, SUB 1	(09/20/2017)
South End Apartments, LLC		
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South Square Owner, LLC		
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Southport Heather Ridge, LLC		
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Southwood Realty Company		
(Azalea Apartments)	WR-910, SUB 18	(02/15/2017)
(Carriage House Apartments)	WR-910, SUB 19	(02/15/2017)
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(Quail Woods Apartments)	WR-910, SUB 21	(02/15/2017)
(Catawaba Apartments)	WR-910, SUB 23	(07/18/2017)
SPUS7 Tribute, LP		
(The Tribute Apartments)	WR-1846, SUB 3	(09/26/2017)
SRC Candler, LLC		
(The Haven Apartments)	WR-2337, SUB 1	(07/05/2017)
SRC Dilworth, Inc.		
(Dilworth Apartments)	WR-2195, SUB 1	(07/05/2017)
SRC Northwinds, Inc.		
(Northwinds I and II Apartments)	WR-1254, SUB 6	(07/14/2017)
Steele Creek Apartments Property Owner, LLC		
(Park at Steele Creek Apartments)	WR-1332, SUB 2	(06/06/2017)
Stephens Pointe, LLC		
(Stephens Pointe Apartments)	WR-1746, SUB 1	(08/04/2017)
Sterling Arbor Creek, LLC		
(Arbor Creek Apartments)	WR-1906, SUB 2	(08/01/2017)
Sterling Forest, LLC		
(The Forest Apartments)	WR-2230, SUB 1	(09/27/2017)
Sterling Reserve at Magnolia Ridge LLC		
(Reserve at Magnolia Ridge Apts.)	WR-1949, SUB 2	(09/27/2017)
Sterling TC Property Owner, LLC		
(Sterling TownCenter Apartments)	WR-1710, SUB 2	(11/06/2017)
Strawberry Hill Associates, LP		
(Strawberry Hills Apartments)	WR-293, SUB 12	(09/19/2017)
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(Tyvola Centre Apartments)	WR-983, SUB 3	(05/30/2017)
(Tyvola Centre Apartments)	WR-983, SUB 4	(08/09/2017)
Summerlyn Holdings, LLC		
(Summerlyn Cottages Apartments)	WR-1689, SUB 3	(07/26/2017)

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(Sunstone Apartments)	WR-2164, SUB 1	(08/30/2017)
SVF Weston Lakeside, LLC		
(Weston Lakeside Apartments)	WR-601, SUB 10	(08/31/2017)
Tanglewood Lake Apts., LLC		
(Tanglewood Lake Apartments)	WR-1015, SUB 5	(03/01/2017)
TGM Rock Creek, LLC		
(Rock Creek Apartments)	WR-1393, SUB 2	(07/03/2017)
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(Alexander Place Apartments)	WR-2220, SUB 1	(10/16/2017)
Threshold Carolinas 15 – CVP, LLC, et al.		
(Crossroads at Village Park Apts.)	WR-2222, SUB 1	(09/18/2017)
Threshold Carolinas 15 – FR, LLC, et al.		
(Forest Ridge Apartments)	WR-2221, SUB 1	(10/12/2017)
Threshold Carolinas 15 – HF, LLC, et al.		
(Hampton Forest Apartments)	WR-2219, SUB 1	(10/18/2017)
Threshold Carolinas 15 – VB, LLC, et al.		
(The Village at Brierfield Apts.)	WR-2223, SUB 1	(09/18/2017)
Threshold Hidden Cove, LLC		
(Lakewood Apartments)	WR-2358, SUB 1	(11/20/2017)
Tilden Legacy Beech Lake Apartments, LLC		
(Beech Lake Apartments)	WR-1947, SUB 2	(10/17/2017)
Town & Country Mobile Home Park, LLC		
(Town and Country Mobile HP)	WR-2255, SUB 1	(09/08/2017)
TP 1100 South Blvd, LLC		
(1100 South Apartments)	WR-1817, SUB 3	(09/20/2017)
Trade & Graham Associates, LLC		
(The Mint Apartments)	WR-1966, SUB 2	(12/18/2017)
Tradition at Stonewater Apartments, LLC		
(Tradition at Stonewater Apartments)	WR-1723, SUB 3	(10/09/2017)
Trellis Pointe, LLC		
(Trellis Pointe Apartments)	WR-14, SUB 4	(09/08/2017)
Treybrooke, LLC		
(Treybrooke Apartments)	WR-824, SUB 4	(07/14/2017)
Triangle Mills Creek, Inc.		
(Mills Creek Apartments)	WR-1580, SUB 1	(02/15/2017)

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Triangle Real Estate of Gastonia, Inc.		
(Hudson Woods Apartments)	WR-1125, SUB 32	(02/15/2017)
(Avalon at Sweeten Creek Apartments)	WR-1125, SUB 34	(07/05/2017)
(The Palisades at Legacy Oaks Apts.)	WR-1125, SUB 35	(07/14/2017)
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(Lake Mist Apartments)	WR-1125, SUB 37	(07/24/2017)
(Arborgate Apartments)	WR-1125, SUB 38	(07/24/2017)
(Woodbridge Apartments)	WR-1125, SUB 39	(07/24/2017)
(Eagle's Walk Apartments)	WR-1125, SUB 40	(07/24/2017)
(Huntersville Commons Apartments)	WR-1125, SUB 41	(07/24/2017)
(Pinetree Apartments)	WR-1125, SUB 42	(08/16/2017)
(Woodbridge Apartments)	WR-1125, SUB 43	(08/16/2017)
(Lake Mist Apartments)	WR-1125, SUB 44	(08/16/2017)
(Eagle's Walk Apartments)	WR-1125, SUB 45	(08/16/2017)
(Huntersville Commons Apartments)	WR-1125, SUB 46	(08/16/2017)
(Arborgate Apartments)	WR-1125, SUB 47	(08/16/2017)
Trinity Properties, LLC		
(Georgetown Apartments)	WR-1696, SUB 16	(08/02/2017)
Trotter Company		
(Elmsley Grove Apartments)	WR-593, SUB 4	(07/27/2017)
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TS New Bern, LLC		
(Fountains Southend Apartments)	WR-1541, SUB 4	(10/30/2017)
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Uptown Court, LLC		
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Village at Broadstone Station I, LLC, et al.		
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Village Creek West Properties I, LLC		
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Village Gate Partners, LLC		
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(Meriwether Place Apartments)	WR-1509, SUB 4	(07/27/2017)
VTT Charlotte, LLC		
(Woodland Estates Apartments)	WR-1506, SUB 3	(07/27/2017)
Vyne on Central Partners, LLC		
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Wafra Invest Loft 135, LP		
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Wake Forest Apartments, LLC		
(Aston Apartments)	WR-1510, SUB 3	(11/28/2017)
Walden Court, Inc.		
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Walden/Greenfields, LLC		
(Sagebrook of Chapel Hill Apts.)	WR-287, SUB 7	(05/02/2017)
Water Garden Village, LLC		
(Water Garden Village Apartments)	WR-1315, SUB 5	(08/10/2017)
Water Oak NC Partners, LLC		
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Waterford at the Park DE, LLC		
(Waterford at the Park Apartments)	WR-1654, SUB 2	(02/20/2017)
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Waterford Lakes NC Partners, LLC		
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Waterford Square Apartments Associates, LLC		
(Waterford Square Apartments)	WR-251, SUB 9	(08/17/2017)
Waterford Valley NC Partners, LLC		
(Arboretum at Southpoint Apts.)	WR-2183, SUB 1	(08/15/2017)

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Waypoint Stone Hollow Owner, LLC		
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WE McAlpine Creek Owner, LLC		
(1700 Place Apartments)	WR-1790, SUB 2	(05/22/2017)
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Wembley Apartments, LLC		
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West Market Partners, LLC		
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West Montecito Company L. P.		
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West Morgan, LLC		
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Westdale Arrowhead Crossing NC, LLC		
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Westdale Brentmoor, LLC		
(Brentmoor Apartments)	WR-1317, SUB 5	(09/19/2017)
Westdale Chase on Monroe NC, LLC		
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Westdale Galleria Village, LLC		
(Galleria Apartments Homes)	WR-1224, SUB 6	(09/18/2017)
Westdale NC Summit Creek, Ltd.		
(Johnston Creek Crossing Apts.)	WR-826, SUB 9	(09/19/2017)
Westdale Peppertree, Ltd.		
(Peppertree Apartments)	WR-815, SUB 9	(09/19/2017)
Westdale Popular Place, LLC		
(Poplar Place Apartments)	WR-816, SUB 6	(08/25/2017)
Westdale Sabal Point NC, LLC		
(Sabal Point Apartments)	WR-636, SUB 10	(09/18/2017)
Westdale Willow Glen NC, LLC		
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WGL Associates, LLC		
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W-GV Greenway Village Holdings VII, LLC		
(Sojourn Lake Boone Apartments)	WR-2018, SUB 2	(11/20/2017)
Willow Run, LLC		
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Winter Oaks NC Partners, LLC		
(Aurea Station Apartments)	WR-1853, SUB 2	(08/22/2017)
WMCi Raleigh I, LLC		
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WMCi Raleigh II, LLC		
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WMCi Raleigh III, LLC		
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WMCi Raleigh IV, LLC		
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WMCi Raleigh V, LLC		
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WMCi Raleigh VI, LLC		
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WMCi Raleigh VII, LLC		
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WMCi Raleigh VIII, LLC		
(The Bristol at Park West Village Apts.)	WR-1693, SUB 3	(07/12/2017)
WMCi Raleigh IX, LLC		
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Woodland Estates Mobile Home Park, LLC		
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WOP Cornerstone, LLC		
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WRPV XII Addison Park Charlotte, LLC		
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WRPV XII Regatta Raleigh, LLC		
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XC Apartments, LLC		
(Cross Creek Apartments)	WR-2125, SUB 1	(07/24/2017)
Yards at Noda, LLC		
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(Village Park M. H. Community)	WR-1336, SUB 29	(09/25/2017)
(Gallant Estates M. H. Community)	WR-1336, SUB 23	(05/08/2017)
(Gallant Estates M. H. Community)	WR-1336, SUB 30	(09/25/2017)
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(Oakwood Forest M. H. Community)	WR-1336, SUB 31	(09/25/2017)
(Foxhall Village M. H. Community)	WR-1336, SUB 25	(05/08/2017)
(Foxhall Village M. H. Community)	WR-1336, SUB 32	(09/25/2017)
(Green Spring Valley M. H. Community)	WR-1336, SUB 26	(05/08/2017)
(Green Spring Valley M. H. Community)	WR-1336, SUB 33	(09/25/2017)
(Stony Brook North M. H. Community)	WR-1336, SUB 27	(05/08/2017)
(Stony Brook North M. H. Community)	WR-1336, SUB 34	(09/25/2017)
York Ridge Associates, LP		
(York Ridge Apartments)	WR-1451, SUB 4	(08/23/2017)
Zell 21, LLC		
(Weaverville Commons Apts.)	WR-2100, SUB 1	(10/16/2017)
2 Hiltin Place Greensboro, LLC		
(Park Place Apartments)	WR-1473, SUB 3	(08/10/2017)
7th Street Progression Partners, LLC		
(The Langston Apartments)	WR-2271, SUB 1	(08/02/2017)

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(Alta Springs Apartments)	WR-47, SUB 13	(10/23/2017)
102 North Elm Street Tenant, LLC		
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330 West Tremont, LLC		
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401 South Mint Street Apartment Investors, LLC		
(Element Uptown Apartments)	WR-1634, SUB 3	(08/08/2017)
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905 7TH, LLC		
(Westchester Apartments)	WR-2060, SUB 1	(07/26/2017)
1052, LLC		
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1300 Knoll Circle Apartments Investors, LLC		
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(Clairmont at Hillandale Apartments)	WR-1118, SUB 4	(08/23/2017)
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(Emory Woods Apartments)	WR-2128, SUB 1	(09/19/2017)
1752, LLC		
(Clairmont at Perry Creek Apts.)	WR-2021, SUB 2	(07/26/2017)
2052, LLC		
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(Country Club Apartments)	WR-1781, SUB 1	(10/02/2017)
3217 Shamrock, LLC		
(Windsor Harbor Apartments)	WR-2147, SUB 1	(08/31/2017)
3500 Spanish Quarter, LLC		
(Greenbryre Apartments)	WR-2116, SUB 1	(08/08/2017)
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(Villagio Apartments)	WR-1973, SUB 2	(08/04/2017)

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4700 Twisted, LLC		
(Wellington Farms Apartments)	WR-1885, SUB 1	(09/08/2017)
5115 Park Place Owner, LLC		
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5205 Barbee Chapel Road Apartments Investors I, LLC		
(Springs of Chapel Hill Apartments)	WR-1505, SUB 4	(10/23/2017)
5625 Keyway Blvd L.P.		
(Cameron at Hickory Grove Apts.)	WR-2003, SUB 1	(08/22/2017)
5725 Carnegie Boulevard Apartment Investors, LLC		
(LaVie Southpark Apartments)	WR-2001, SUB 2	(08/10/2017)
5920 Monroe, LLC		
(Hanover Landing Apartments)	WR-1780, SUB 1	(08/24/2017)
6000 Delta Crossing Lane L.P.		
(Delta Crossing Apartments)	WR-2004, SUB 1	(08/18/2017)
6200 Raleigh Apartments, LLC		
(Andover at Crabtree Apartments)	WR-1882, SUB 2	(09/19/2017)
7850 Cottage Cove, LLC		
(Cottage Cove Mobile Home Park)	WR-1196, SUB 2	(09/06/2017)
7850 Homestead Village, LLC		
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Brook Dana, LLC		
(Brook Hill Apartments)	WR-1281, SUB 7	(07/11/2017)
Casa United, LLC		
(Casa Del Sol Apartments)	WR-2179, SUB 2	(09/08/2017)
CDC-Durham/UC, LLC		
(Duke Villa Apartments)	WR-1100, SUB 12	(02/02/2017)
Central Pointe Apartments, LLC		
(Central Pointe Apartments)	WR-1479, SUB 4	(01/09/2017)
Clemmons Trace Village, LLC		
(Clemmons Trace Apartments)	WR-1995, SUB 2	(10/24/2017)
CSC Midtown, LLC		
(Midtown Park Townhomes Apts.)	WR-1482, SUB 3	(02/20/2017)
Fairfield Reafield Village, LLC		
(Reafield Village Apartments)	WR-1774, SUB 3	(10/31/2017)
FC Hidden Creek, LLC		
(North Oaks Landing Apartments)	WR-1724, SUB 4	(11/28/2017)
G&I VIII Midtown 501, LLC		
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Ginkgo Croasdaile, LLC		
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Ginkgo Glendare, LLC		
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(Glendare Park Apartments)	WR-1968, SUB 2	(11/14/2017)
Ginkgo Parkwood, LLC		
(Parkwood Apartments)	WR-2275, SUB 1	(12/04/2017)
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Glen K, LLC; The		
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Gorman Crossing, LLC		
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Graybul Meadows, LP		
(The Meadows Apartments, Phase I)	WR-2030, SUB 6	(09/07/2017)

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HR Realty Company, LLC		
(Hunting Ridge Apartments)	WR-1161, SUB 7	(07/10/2017)
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(Lexington Farms Apartments)	WR-1823, SUB 3	(10/18/2017)
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Kip-Dell Homes, Inc.		
(Pine Winds Apartments)	WR-341, SUB 11	(07/13/2017)
Lake Clair, LLC		
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Merriwood Associates Limited Partnership		
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Montecito Company, LLC		
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Monument Northpoint, LLC		
(901 Center Station Apartments)	WR-2180, SUB 2	(09/08/2017)
Oakhurst Farms of Raleigh, LLC		
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PC Oxford, LLC		
(Oxford Square Apartments)	WR-1383, SUB 4	(09/05/2017)
Penrith Townhomes, LLC		
(Woodland Creek Apartments)	WR-1763, SUB 5	(08/09/2017)
Princeton Villas, LLC		
(Rosewood Apartments)	WR-1971, SUB 14	(08/23/2017)
(Eastwood Apartments)	WR-1971, SUB 15	(08/23/2017)
(Oakwood Apartments)	WR-1971, SUB 13	(08/23/2017)
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(Princeton Apartments)	WR-1971, SUB 16	(08/23/2017)
(Briarwood Apartments)	WR-1971, SUB 17	(08/23/2017)
QR Realty Company, LLC		
(Quail Ridge Apartments)	WR-1159, SUB 7	(07/05/2017)
RCG Skyland, LLC		
(Skyland Heights Apartments)	WR-2312, SUB 1	(11/27/2017)

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RP Barnes, LLC		
(University Lake Apartments)	WR-1285, SUB 3	(03/08/2017)
(Royal Park Apartments)	WR-1285, SUB 4	(03/08/2017)
SBV-Greensboro-II, LLC		
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