ONE-HUNDRED SECOND REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2012, through December 31, 2012

Edward S. Finley, Jr., Chairman

William T. Culpepper, III, Commissioner

Bryan E. Beatty, Commissioner

Susan W. Rabon, Commissioner

ToNola D. Brown-Bland, Commissioner

Lucy T. Allen, Commissioner

North Carolina Utilities Commission
Office of the Chief Clerk
Gail L. Mount
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.

LETTER OF TRANSMITTAL

December 31, 2012

The Governor of North Carolina
Raleigh, North Carolina

Madam:

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, 2012, we hereby present for your consideration the report of the Commission's significant decisions for the 12-month period beginning January 1, 2012, and ending December 31, 2012.

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

William T. Culpepper, III, Commissioner

Bryan E. Beatty, Commissioner

Susan W. Rabon, Commissioner

ToNola D. Brown-Bland, Commissioner

Lucy T. Allen, Commissioner

Gail L. Mount, Chief Clerk

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BEFORE THE NORTH CAROLINA UTILITES COMMISSION
DOCKET NO. M-89, SUB 7

In the Matter of Kenneth and Paula Waldroup, 711 Long Creek Road, Robbinsville, North Carolina, Complainant, v. Duke Energy Carolinas, LLC, and Frontier Communications of the Carolinas, Inc., Respondents.	)	ORDER REQUIRING INITIATION OF CONDEMNATION PROCEEDINGS

HEARD: Tuesday, June 21, 2011, at 9:30 a.m., Commission Hearing Room 2115, Dobbs Building, Raleigh, North Carolina

BEFORE: Commissioner William T. Culpepper, III, Presiding, Commissioner Bryan E. Beatty and Commissioner Lucy T. Allen

APPEARANCES:

For the Complainants:

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For Duke Energy Carolinas, LLC:

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For Frontier Communications of the Carolinas, Inc.:

Daniel C. Higgins
Burns, Day & Presnell, P.A.
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Raleigh, North Carolina 27605

BY THE COMMISSION: On November 10, 2010, Kenneth and Paula Waldroup ("Complainants" or "Waldroups") filed a formal complaint ("Complaint") against Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company") and Frontier Communications of the Carolinas, Inc. ("Frontier") (collectively, "Respondents"), requesting the North Carolina Utilities Commission ("the Commission") to order Duke Energy Carolinas to obtain an easement by exercise of the power of eminent domain and to order Duke Energy Carolinas and Frontier to provide electric and telephone utility service to Complainants' 47.55 acre parcel of real property so they could develop it for residential use. By Order dated November 12, 2010, the Commission served the Complaint on Duke Energy Carolinas and Frontier.

On November 24 and November 29, 2010, Duke Energy Carolinas and Frontier, respectively, each filed a motion for extension of time to answer and respond to the Complaint. By Order issued November 30, 2010, the Commission allowed Duke Energy Carolinas' and Frontier's motions. On December 3, 2010, Duke Energy Carolinas filed a second motion for extension of time to answer and to respond to the Complaint. By Order issued December 7, 2010, the Commission allowed Duke Energy Carolinas' motion.

On December 21, 2010, Duke Energy Carolinas and Frontier each filed Answers and Motions to Dismiss the Complaint.

On January 14, 2011, Complainants filed their reply indicating that the Answers filed by Duke Energy Carolinas and Frontier were not satisfactory and requesting a public hearing to present evidence. On February 14, 2011, the Commission issued its Order Scheduling Hearing in this docket. On March 7, 2011, the Respondents jointly filed a motion to continue the evidentiary hearing. On March 11, 2011, the Commission issued its Order rescheduling the evidentiary hearing.

On April 14, 2011, Duke Energy Carolinas filed a Motion to Compel Responses to First Data Request and Motion to Continue Evidentiary Hearing. On April 20, 2011, the Commission issued its Order Continuing Evidentiary Hearing and Compelling Response to First Data Request. On April 26, 2011, Complainants filed their response to Duke Energy Carolinas' data request.

On June 3, 2011, the Commission issued its Order Scheduling Evidentiary Hearing setting the matter for hearing on June 21, 2011.

This case came on for hearing, as ordered, on June 21, 2011. Complainants presented the testimony of Paula Waldroup. Duke Energy Carolinas presented the testimony of Jim Douthit and Barbara Yarbrough. Frontier presented the testimony of Stan Pace.

Based on consideration of the pleadings, testimony and exhibits received into evidence at the hearing, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Respondent Duke Energy Carolinas is a public utility providing electric utility service to customers in its assigned service territory in North Carolina, subject to the jurisdiction of the Commission.

2. Respondent Frontier is a public utility providing telephone service to customers in its assigned service territory in North Carolina, subject to the jurisdiction of the Commission.

3. Complainants own a tract of land (the "Waldroup Property") consisting of approximately 47.55 acres, bordered by Fontana Lake and the United States Forest Service, in Graham County, North Carolina, located in Duke Energy Carolinas' assigned service territory. The Waldroup Property is also in Frontier's assigned service territory, and Frontier has carrier of last resort obligations to property in that area.

4. Joseph Edwards ("Mr. Edwards") owns a tract of land ("Edwards Property") adjacent to the Waldroup Property. Complainants have contacted Duke Energy Carolinas requesting installation of electric infrastructure to the Waldroup Property which they wish to develop as a residential subdivision. Complainants have also approached Frontier about installing facilities to provide telephone service to the Waldroup Property.

5. To date, no individual has requested electric service either for construction of, or to, a permanent residence on the Waldroup Property, and no individual has requested that Frontier provide phone service to any customer on the Waldroup Property.

6. The most feasible way to install electric infrastructure to serve the Waldroup Property is across the Edwards Property.

7. Documentation associated with the Special Proceeding for Partition in Graham County, File No. 04 SP 8 (" the Partition Proceeding"), of the larger tract that consisted of both the Waldroup Property and the Edwards Property, indicates that "a 45-foot right of way across the existing road is considered reasonable for access to parcel '2'" (parcel 2 being the Waldroup Property) was granted to Complainants, but that right of way does not include an easement for utilities, i.e. an easement allowing placement of electric and/or telephone facilities.

8. The Complainants engaged in negotiations with Mr. Edwards to secure a utility easement to be located within the 45 foot right of way across the existing road so that telephone and electrical service might be provided to the Waldroup Property. Complainants presented Mr. Edwards with a written agreement incorporating the concessions that Complainants were willing to make to secure the easement across the Edwards Property. Included in those concessions was the construction of a road ("the road") across the 45 foot right of way. As of the date of the hearing, Mr. Edwards has not signed the agreement.

9. Duke Energy Carolinas has been in contact with Mr. Edwards on numerous occasions in an attempt to establish an easement to permit electric utility service to be provided to the Waldroup Property. Based on these contacts with Mr. Edwards, the Company understood that Mr. Edwards would provide the Company with an easement if the Company modified its standard easement agreement to include language that the Modified Right-of-Way Agreement

("Modified Agreement") would not be recorded until the road was built to final grade. The Company presented the Modified Agreement to Mr. Edwards for his review and signature in July 2010.

10. Mr. Edwards informed the Company that he wanted to have the Modified Agreement reviewed by his attorney when it was initially given to him in July 2010.

11. The Company contacted Mr. Edwards on a number of occasions to inquire about the status of the Modified Agreement. When asked about the status of the Modified Agreement by the Company during these subsequent inquiries, Mr. Edwards' only response was that he would have or wanted to have the Modified Agreement reviewed by his attorney.

12. There is no evidence that Mr. Edwards ever had the Modified Agreement reviewed by an attorney.

13. As of the date of the hearing, Mr. Edwards had not signed the Modified Agreement.

14. Duke Energy Carolinas' plans have been to install underground electric utility lines within the 45-foot right-of-way, once the road is upgraded per design and any required Contribution in Aid of Construction and/or Idle Facilities Deposits have been paid by Complainants. The Company's Underground Distribution Installation Plan requires that final grade levels be established before the Company installs any underground distribution lines.

15. The least cost design to provide electric utility service to the Waldroup Property is through the use of an overhead system using the most direct route determined to be feasible from an engineering standpoint.

16. The Company has been unwilling to initiate condemnation proceedings to provide electric utility service to the Waldroup Property because Mr. Edwards informed the Company that he would grant the Complainants a utility easement if they would satisfy his conditions.

17. After conducting extensive discussions with Mr. Edwards, the Complainants and the Company independently drafted agreements that included the terms that Mr. Edwards indicated would induce him to grant an easement to the Company so that electric utility service might be provided to the Waldroup Property. Mr. Edwards has refused to sign either agreement.

18. Mr. Edwards' refusal to sign either of the agreements is persuasive evidence that he will not provide a utility easement to the Complainants.

19. The Company and the Complainants have exhausted all reasonable efforts to secure a utility easement from Mr. Edwards.

20. Further efforts by the Complainants and the Company to secure an easement from Mr. Edwards would be futile.

21. The Company has an obligation to provide electric utility service to the Waldroup Property which cannot be fulfilled unless the Company initiates a condemnation proceeding against Mr. Edwards.

22. Frontier has an obligation to provide telephone utility service to the Waldroup Property which cannot be fulfilled unless a condemnation proceeding against Mr. Edwards is initiated.

LEGAL STANDARD

In accordance with N.C. Gen. Stat. § 62-75, Complainants have the burden of proving that that the relief requested in the Complaint is warranted under the facts and circumstances presented in this case. *See Welch v. Nantahala Power & Light Company*, E-7, Sub 674 (2001) (holding that the burden of proof is on the Complainant in a customer complaint proceeding).

EVIDENCE IN SUPPORT OF FINDING OF FACTS AND CONCLUSIONS

The evidence in support of the findings is found in the testimony of Complainant Paula Waldroup, Duke Energy Carolinas' witnesses Barbara Yarbrough and Jim Douthit, and Frontier's witness Stan Pace, as well as the exhibits presented by the parties.

Complainants have alleged that Duke Energy Carolinas has refused to exercise its power of eminent domain to obtain a utility service easement over the Edwards Property which is necessary for installing facilities to provide electric utility service to the Waldroup Property. Complainants argue that it is necessary for Respondents to acquire easements by condemnation, because Mr. Edwards has refused to grant Complainants a right of way over his property for Complainants to receive electric and telephone service from Respondents in order to move forward with a planned subdivision.

At the evidentiary hearing, Ms. Waldroup testified that she and Mr. Edwards (her brother) inherited property from their father that became the subject of a Partition Proceeding. In that proceeding, that property was divided and Mr. Edwards was awarded the portion of the property closer to the public road, i.e., the Edwards Property. The Edwards Property has electrical service, but that service does not extend to the portion of the property awarded to Ms. Waldroup, i.e., the Waldroup Property. The Waldroup Property faces Fontana Lake and is otherwise surrounded by national forest lands. The only private property bordering the Waldroup Property is the Edwards Property. It is uncontroverted that the Waldroup Property is within the respective service territories of the Respondents.

Ms. Waldroup further testified that, also as a result of the Partition Proceeding, she received a 45-foot-wide easement over the Edwards Property. Late-filed exhibits filed by the Complainants reference the right of way and include a document from Investors Title Insurance Company describing that easement as "a perpetual, appurtenant, and nonexclusive road right of way easement over and across the existing access road, for ingress and egress to and from lands herein conveyed and the public road." The Waldroups have intended to have Duke Energy Carolinas and Frontier bury electrical and phone cables entirely within this 45-foot road easement to deliver the electrical and phone service to the intended development on the Waldroup Property.

According to Ms. Waldroup, she asked Mr. Edwards to sign a power-line easement so that electrical service might be provided to the Waldroup Property. She offered Mr. Edwards a written contract in which the Complainants agreed to construct a new road and build a retaining wall in exchange for the utility easement. The contract was prepared as a result of discussions about the matter between legal counsel for the Waldroups and Mr. Edwards. Mr. Edwards, however, has refused to sign that contract. Ms. Waldroup also testified that the Waldroups have deeded two lots in their subdivision to others in exchange for services provided to them. No one, however, is living anywhere on the Waldroup Property at the present time, and there is also no permanent structure located thereupon and currently no construction ongoing on the Waldroup Property.

Duke Energy Carolinas' witness Jim Douthit, an engineer for the Company, testified that his responsibilities include meeting with customers to determine the most cost-efficient design for electrical routes to residential and commercial properties. To this end, Mr. Douthit testified that he assists in ensuring that the Company obtains the necessary easements prior to any construction across any property. Mr. Douthit testified that he first met with Mr. Waldroup in 2009, when Mr. Waldroup requested establishment of electrical service to the Waldroups' proposed subdivision, Cricket Cove. At that time, Mr. Douthit explained to Mr. Waldroup that, to get power to the Waldroup Property, Mr. Waldroup would need to obtain an easement from the closest electric utility pole on the Edwards Property. Mr. Waldroup indicated to Mr. Douthit that obtaining an easement from Mr. Edwards might be difficult due to a family dispute over the division of the property.

Witness Douthit testified that after meeting with Mr. Waldroup, he met with Mr. Edwards on the Edwards Property. Mr. Edwards did not refuse to grant an easement to the Complainants, but he indicated to Mr. Douthit that he wanted the road improved to certain existing specifications first. Witness Douthit testified that in his six to eight conversations with Mr. Edwards about granting a utility easement, Mr. Edwards never refused to sign the easement agreement, but instead continued to request that the road be improved.

Witness Douthit further testified that he met with Mr. Edwards again in a further effort to resolve this matter in June - July 2010. During the course of these meetings, Mr. Edwards informed Mr. Douthit that he would provide the Company with an easement if the Company modified its form easement to include language that the Company would not record the easement until the road was built to final grade. In July 2010, Mr. Douthit presented Mr. Edwards with the Modified Agreement providing that Duke Energy Carolinas would not exercise its rights to install underground electric facilities under that agreement unless and until a roadway has been installed across the premises within the access easement area and in compliance with certain design specifications. Witness Douthit testified that Mr. Edwards stated that he would talk to his attorney about the Modified Agreement. Mr. Douthit also testified that when he asked Mr. Edwards about the status of the agreement in the many subsequent conversations that they had, Mr. Edwards would respond that he needed to have his attorney review it. Witness Douthit further testified that he was never advised that Mr. Edwards' attorney had reviewed the document.

Witness Douthit also testified that he had explained to Mr. Edwards that the most feasible and cost-effective route for power delivery to the Waldroup Property would be an overhead route, which might be straight through the middle of his property with an overhead aerial line with poles. Moreover, witness Douthit also explained to Mr. Edwards that if he did not provide the written right of way to the Company, Mr. Edwards may face condemnation. Witness Douthit also testified that he explained to Mr. Edwards that the overhead route would be considerably less expensive than the underground route that Mr. Edwards preferred.

Duke Energy Carolinas' witness Barbara Yarbrough testified first about the Company's service regulations as approved by the Commission, noting that the Company's service regulations indicate that a right of way is needed, that the obligation of the Company to supply service is dependent upon the Company securing and obtaining all necessary rights of way, and that the Company should not be liable to the customer for the failure to deliver service if no such right of way is provided. Witness Yarbrough testified that her understanding was that the Waldroups' primary objective is to have facilities installed that would not initially be used to provide permanent electric service and that the Company's plans all along have been to install underground electric facilities across the Edwards' Property to reach the Waldroup Property largely within the 45-foot access right of way.

Company witness Yarbrough further testified that Mr. Edwards did not want to sign the Company's Right of Way Agreement because he did not believe that the Waldroups would make the desired improvements once he had granted the right of way, and that Mr. Edwards did not want to have to pursue any legal action to compel the Waldroups to satisfy any agreed upon conditions regarding the roadway improvements contained in the contract. Additionally, witness Yarbrough testified that Mr. Edwards indicated that he did not believe that the Waldroups had the funds necessary to make the improvements to the road.

Witness Yarbrough also testified about the Company's underground distribution installation plan ("the Installation Plan"), which has been approved by the Commission, and which sets forth all information regarding the conditions and costs of providing underground service. According to the Installation Plan, the Company must know how the road will be constructed prior to installing facilities and the road must be at final grade before installation is authorized. Witness Yarbrough further testified that photographs introduced into evidence showed that the access road was not at final grade and the entire 45-foot width of the right of way has not been cleared.

Witness Yarbrough concluded that, in this case, there were two property owners that could not agree on the sequence of events regarding improvement of the road and the installation of electric service. She believed that if the Waldroups would complete the improvements to the road necessary to install facilities and set up an escrow account to ensure funds were available to complete minor repairs after installing the underground lines, the matter may be resolved for Mr. Edwards.

Frontier's witness Stan Pace testified that Frontier has not received any requests for service at the Waldroup Property and that he was not aware of any construction taking place on the Waldroup Property. Frontier has a policy whereby it will start engineering the cable to go in the conduit after construction of a home has actually begun. Witness Pace testified that Frontier has estimated that it would take approximately $25,000 to $30,000 of cable along the road right of way to serve proposed lots on the Waldroup Property; and that it would be more expensive if the Waldroup Property was to be served by an aerial facilities placement. Witness Pace testified that, without customers to serve, investing in installing facilities to the Waldroup Property was not prudent.

To summarize, in this proceeding, it is undisputed that the only feasible way for the Company to deliver service to the Waldroup Property is over the Edwards Property; to date, Mr. Edwards has not provided an easement to the Company so that the Waldroup Property can be served by the Respondents; that Mr. Edwards has participated in extensive negotiations with the Waldroups which resulted in the Waldroups drafting a document memorializing terms that Mr. Edwards had agreed to accept in return for granting the Complainants an easement; that Mr. Edwards refused to sign the agreement; that Mr. Edwards participated in extensive negotiations with Mr. Doughit, a representative of the Company, which resulted in the Company drafting a document which memorialized terms that that Mr. Edwards had agreed to accept in return for granting the Company an easement; that Mr. Edwards has refused to sign the document; that the most recent communication that Mr. Edwards sent to the Company once again indicates that he will grant an easement to the Company if his conditions are met; that Mr. Edwards and the Complainants and/or the Company have been engaged in discussions surrounding this easement since 2010; and that Mr. Edwards has yet to grant an easement.

CONCLUSIONS

The Complainants contend that they have exhausted all reasonable efforts to secure a utility easement from Mr. Edwards and that it is, therefore, appropriate for the Company to be required to exercise the power of eminent domain that has been granted to it by statute in order to provide electric utility service to the Waldroup Property.

The Company disagrees. It contends that it has acted reasonably in refusing to initiate a condemnation proceeding to secure a utility right-of-way because Mr. Edwards has not refused outright to grant the needed right of way. The Company believes that this matter could be resolved without resorting to condemnation if the Complainants would complete the improvements to the access road across the Edwards Property as Mr. Edwards has requested. Company witness Yarborough testified that she believed that the matter may be resolved if the Waldroups would complete the improvements to the road necessary to install facilities and set up an escrow account to ensure funds were available to complete minor repairs after installing the underground lines because Mr. Edwards has indicated he would grant the easement under those conditions.

The Commission has previously considered similar issues regarding property owners who desire a utility to condemn a neighbor's property so that they might receive utility service in *Tucker v. Duke Power Company*, Docket No. E-7, Sub 483, 1991 WL 516982 (Oct. 14, 1991)(*Tucke*r) and *Welch v. Nantahala Power and Light Company, a Division of Duke Energy Corporation*, Docket No. E-7, Sub 674, 2001 WL 1943883(Sept. 20, 2001)(*Welch).* Both *Tucker* and *Welch* stand for the proposition that condemnation should only be pursued "as a last resort." After carefully examining the facts and the law, the Commission decided in *Tucker* that the utility should be required to pursue the alternative of last resort, i.e., a condemnation action, to provide service to the complainant, whereas, in *Welch*, after a similar examination, the Commission decided that a condemnation action was not required.

In their Joint Proposed Order, the Respondents argue that the current case is analogous to *Welch* and dissimilar to *Tucker*. Because of this dynamic, the Respondents assert that it is inappropriate for this Commission to require pursuit of the alternative of last resort, i.e., a condemnation action. The Commission disagrees for the following reasons.

In *Welch,* the more recent of the two decisions, the Commission did indeed decide that it was not reasonable for the Commission to order the utility to "simultaneously" pursue a condemnation. The Commission did so, however, only after determining that a civil action had already been initiated in the General Court of Justice to determine the validity of a disputed roadway easement and receiving testimony under oath from the adjoining landowner in the complaint proceeding that he would convey a utility easement to the complainants if the complainants' right to the roadway easement was upheld. In the current proceeding, there is no dispute as to the validity of the roadway easement, there is no testimony under oath from Mr. Edwards that he will grant a utility easement to the Complainants, and there is no pending civil proceeding in which the dispute between the parties can be resolved.

With regard to the latter point, the Respondents suggest that this shortcoming can be overcome by requiring the Complainants to secure an order from the General Court of Justice modifying the prior Partition order to establish a utility right-of-way within the roadway; requiring Mr. Edwards to grant the Complainants a utility right-of-way; or ruling that the Complainants have the legal right to convey utility right-of-ways in the roadway easement granted to Complainants in the Partition Proceeding. While the Respondents forcefully suggest in their Joint Proposed Order that the Complainants should be required to pursue the aforementioned relief in the General Court of Justice before the Commission should require them to pursue condemnation, they have not cited any authority or analysis that would suggest that, under the circumstances present in this case, the General Court of Justice is likely to grant the relief that the Respondents insist that the Complainants should pursue. By contrast, counsel for the Complainants stated in his post-hearing Legal Memorandum that he could find no authority allowing Commissioners in a partition proceeding to grant utility easements, and that he could find no case holding that utilities can be located within a road easement granted in a partition proceeding as a matter of course. The Commission, through independent research, can likewise find no legal authority for the establishment of a utility easement incident to a partition proceeding.

In our view, the facts of the current case are more closely aligned with the facts in *Tucker* than *Welch.* In *Tucker,* the complainants initiated an action seeking a Commission order requiring Duke Power to institute a condemnation action to acquire a court sanctioned utility easement from a neighboring property owner so that electrical power could be extended to their landlocked property. In that case, negotiations had broken down and the owners of the adjacent properties were unwilling to provide a right of way to provide electric service to the complainant's land. *Id.* at *2-*3. Despite this uncontested evidence, Duke Power nevertheless argued that this Commission should not require the Company to initiate an eminent domain proceeding to secure the necessary right of way to provide the complainants with utility service because condemnation should only be used as "a last resort" and that the complainants' situation did not qualify as such because they had a less drastic alternative, i.e., a civil action, available to them that might result in a utility right-of-way being established. After carefully considering the arguments raised by Duke, the Hearing Examiner determined that, under the facts of that case, Duke Power was required to pursue condemnation proceedings to secure a right of way to provide electric service to the complainants' land. In reaching this decision, the Hearing Examiner noted that a complainant should not be forced to pursue a "futile" civil action which "offer[ed] no promise" of success before the public utility company is required to exercise its statutory power to condemn property to provide utility service to a customer. *Id. a*t *6.

In our opinion, the evidence in this case supports a similar conclusion. That is, after carefully reviewing the testimony of the parties, the exhibits presented during the hearing, the post hearing exhibits of the Complainants and the Company's late-filed exhibit, and for the reasons previously discussed in our analysis of the *Tucker* and *Welch* decisions, we are compelled to conclude that the Complainants have no real likelihood of securing a utility easement in the General Court of Justice. It would, therefore, be futile to require the Complainants to pursue an alternative that offers no chance of success.

In addition, the Commission is compelled to reject the Company's suggestion that the Complainants should accede to the demands of Mr. Edwards before it should be forced to pursue an eminent domain action to secure the necessary easement. The Company asserts that Mr. Edwards has indicated that he will grant the easement if his conditions are met and, in *Welch*, this Commission based its decision to delay action on a complainant's request for a utility to pursue an eminent domain action on a landowner's assertion that he would grant the easement if a certain condition was met. In this case, however, unlike, *Welch,* the Commission was not privileged to hear any testimony from the individual who would be required to grant the easement, i.e., Mr. Edwards.[1] The Commission was nevertheless privy to the testimony of Ms. Waldroup and the Companies' witnesses about the actions of Mr. Edwards and can draw some conclusions therefrom about the likelihood that Mr. Edwards would indeed grant the easement Complainants have sought.

According to the undisputed testimony of both Ms. Waldroup and Company witness Doughit, Mr. Edwards has previously agreed to sign an easement if certain preconditions were satisfied, but thereafter reneged on that agreement by refusing to sign the easement once it was presented to him for signature. The only explanation that Mr. Edwards appeared to offer for his refusal was that he was not convinced that the Complainants had the financial wherewithal to comply with the conditions and that he did not want to have to engage in litigation to ensure that his conditions were met. However, the undisputed evidence presented at the hearing was that the Complainants do in fact have the financial wherewithal to satisfy the agreed upon conditions and that the Company-drafted agreement was crafted so that the easement could not be recorded or used until and unless the conditions demanded by Mr. Edwards were satisfied. Ms. Waldroup testified that her brother, Mr. Edwards, is mad with her; that Mr. Edwards "will never be satisfied no matter what we build"; and that he will never sign an easement. Company witness Doughit gave a long, detailed and believable narrative about his efforts to secure an agreement from Mr. Edwards, only to be rebuffed by new requirements that Edwards needed to be satisfied. Thus, the undisputed and imminently believable testimony given in this proceeding by both the Complainants and the Company indicate that there is a very real likelihood that Mr. Edwards would refuse to sign the easement agreement even after all of his conditions have been satisfied.

[1] Mr. Edwards was not present during and did not testify at the hearing. Nor did the parties offer any depositions, affidavits or any other type of evidence consisting of Mr. Edwards' sworn testimony.

There is an old adage that “actions speak louder than words”. In this case, Mr. Edwards’ prior actions speak louder than his statement that he is willing to grant the right-of-way if the Waldroups will meet his conditions. In our opinion, the evidence presented in this proceeding clearly indicates that Mr. Edwards has repeatedly stonewalled the Complainants and the Company’s efforts to resolve this dispute and that the likelihood of Mr. Edwards honoring any commitment is nil. The Commission therefore determines that requiring the Complainants to continue pursuit of a voluntary easement from Mr. Edwards is futile and offers no possibility of success.

The Commission notes that during the course of this proceeding, the Respondents have expressed concerns about the financial outlays that they would be required to make in order to furnish the Complainants with utility service. Specifically, the Respondents are concerned about the prospect of installing facilities to serve a residential subdivision that does not have and may not have a sufficient number of residents to justify the costs of the installation. However, Respondents’ Commission approved tariffs have explicit provisions that allow the Respondents to require developers to make payments to the Respondents in the form of contributions in aid of construction before the Respondents can be required to furnish service to a development. It is evident from the testimony that the Complainants are acting as developers of their property.

Respondents have been granted an exclusive utility franchise which encompasses certain territory. Within this exclusive territory, Respondents are obliged to provide utility service to any individual or company that desires the utility service provided by Respondents. In return and as an incident to their utility franchise, the General Assembly has authorized the Respondents to exercise the power of eminent domain to ensure that Respondents can satisfy their obligation to serve the residents in their franchised service territory. The Complainants in this case desire service from the utilities serving their territory. The Respondents have an obligation to serve them by reasonable and appropriate means. Under the facts of this case, it is appropriate and reasonable for the Respondents to utilize the power of eminent domain to provide the Complainants with the utility service that they have requested.

Thus, the Commission hereby directs the Company to initiate proceedings in the appropriate forum to acquire by condemnation the right of way necessary to install facilities to serve the Waldroup Property. If Frontier determines that the right-of-way sought by the Company is not suitable to meet the needs and requirements for Frontier to provide service to the Complainants and/or Frontier determines that it is not legally entitled to utilize the easement sought by the Company to provide telephone service, Frontier shall also be required to initiate a condemnation proceeding to secure a suitable right-of-way to provide telephone service to the Waldroup Property.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION
This the _27th___ day of March, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Lh032712.01

DOCKET NO. E-100, SUB 113

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

HEARD: Tuesday, August 28, 2012, and Wednesday, August 29, 2012, at 9:30 a.m., in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner William T. Culpepper, III, Presiding, Chairman Edward S. Finley, Jr., and Commissioners Bryan E. Beatty, Susan W. Rabon, ToNola D. Brown-Bland, and Lucy T. Allen

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For the Public Works Commission of the City of Fayetteville:

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BY THE COMMISSION: On May 16, 2012, the Commission issued an Order directing all of the State's electric power suppliers to file updates on the status of their plans to comply with the swine waste and poultry waste set-aside requirements established in the State's Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Subsections (e) and (f) of G.S. 62-133.8 establish set-asides within the overall renewable energy requirement. They provide that a specified percentage of the power supplied to customers each year must be derived from swine waste or poultry waste. G.S. 62-133.8(e) provides that in 2012 at least 0.07% of an electric power supplier's total 2011 retail sales must come from swine waste, with the percentage increasing to 0.14% in 2015 and 0.20% during and after 2018. G.S. 62-133.8(f) provides that the State's electric power suppliers must collectively provide a total of 170,000 megawatt-hours (MWh) of power generated from poultry waste in 2012, 700,000 MWh in 2013, and 900,000 MWh in 2014 and each year thereafter. The Commission's May 16, 2012 Order noted that REPS compliance plans for 2011, submitted to the Commission as required by Commission Rule R8-67(b) in Docket No. E-100, Subs 128 and 131, and comments filed by the Public Staff in the same dockets, called into question whether the electric power suppliers would meet their 2012 swine and poultry waste set-aside requirements. The Commission required that within 30 days the State's electric power suppliers provide an update to their plans for compliance with the requirements of G.S. 62-133.8(e) and (f) in 2012 and 2013.

In response to the Commission's May 16, 2012 Order, on June 1, 2012, Duke Energy Carolinas, LLC (Duke), Progress Energy Carolinas, Inc. (PEC), Dominion North Carolina Power (DNCP), GreenCo Solutions, Inc. (GreenCo), the Public Works Commission of the City of Fayetteville (Fayetteville), the North Carolina Eastern Municipal Power Agency (NCEMPA), and North Carolina Municipal Power Agency Number 1 (NCMPA1),[1] EnergyUnited Electric Membership Corporation (EnergyUnited), Halifax Electric Membership Corporation (Halifax), and the Tennessee Valley Authority (TVA) (collectively the Joint Movants) filed a Joint Motion to Modify and Delay the Requirements of N.C. Gen. Stat. §§ 62-133.8(e) and (f) Due to Lack of Sufficient Swine and Poultry Waste Resources; and Update Complying with the Requirements of the Order Requiring Update of Plans to Meet Swine and Poultry Waste Set-Aside Obligations (Original Joint Motion). In this motion the Joint Movants requested, pursuant to

[1] NCEMPA and NCMPA1 are hereinafter sometimes referred to as the Power Agencies.

G.S. 62-133.8(i)(2), to be relieved from compliance with subsections (e) and (f) for the year 2012. G.S. 62-133.8(i)(2) is often referred to as the "off-ramp" provision of the REPS statute. It states that the Commission must develop a procedure to modify or delay the provisions of subsections (b), (c), (d), (e), and (f) of G.S. 62-133.8 in whole or in part if the Commission determines that it is in the public interest to do so. G.S. 62-133.8(i)(2) requires that the adopted procedure include a requirement that the electric power supplier demonstrate that it made a reasonable effort to meet the requirements set out in the REPS.

On June 21, 2012, the Commission issued an Order setting the case for hearing, establishing deadlines for filing testimony, and requiring the Joint Movants to respond to certain questions in their direct testimony.

On July 17, 2012, the Joint Movants filed an Amended Joint Motion to Modify and Delay the Requirements of N.C. Gen. Stat. §§ 62-133.8(e) and (f) Due to Lack of Sufficient Swine and Poultry Waste Resources; and Amended Update Complying with the Requirements of the Order Requiring Update of Plans to Meet Swine and Poultry Waste Set-Aside Obligations (Amended Joint Motion). In the Amended Joint Motion, the Joint Movants requested that they be relieved from compliance with G.S. 62-133.8(e) and (f) for two years, rather than only one year as requested in the Original Joint Motion. The Joint Movants requested that all of the deadlines in subdivisions (e) and (f) be extended for a two-year period, so that the electric power suppliers would be required to provide 0.07% of their total retail sales from swine waste in 2014, increasing to 0.14% in 2017, and to provide a collective total of 170,000 MWh of power from poultry waste in 2014, 700,000 MWh in 2015, and 900,000 MWh in 2016 and subsequent years.

On July 18, 2012, petitions to intervene were filed by TVA and Recovered Energy Investments I, LLC (REI). On August 2, 2012, a petition to intervene was filed by Tucker Engineering Associates, Inc. On August 16, 2012, a petition to intervene was filed by Halifax. All these petitions were granted by the Commission. The intervention of the Public Staff is recognized under G.S. 62-15(d). All other parties to the proceeding had previously been made parties by the Commission or allowed to intervene in this docket.

On July 25, 2012, EnergyUnited filed the direct testimony of Alec Natt, its Chief Financial Officer; Fayetteville filed the direct testimony of Keith Lynch, its Power Contracts and Regulatory Manager; NCEMPA and NCMPA1 filed the direct testimony of Andrew M. Fusco, Director of Planning with ElectriCities of North Carolina, Inc.; GreenCo filed the direct testimony of Jason B. Nemeth, its Director, Business Operations; DNCP filed the direct testimony of Chiman H. Muchhala, its Manager of Market Operations; and TVA filed the direct testimony of David B. DeHart, its Program Manager, Renewable Energy. On July 27, 2012, Duke and PEC filed the direct testimony of Jennifer S. Ellis, Duke's Manager of Carolinas Wholesale, and Emily O. Felt, Duke's Director of Renewable Strategy and Compliance, Carolinas. On August 13, 2012, Halifax filed the direct testimony of its Executive Vice President, Charles H. Guerry.

On July 31, 2012, a proposed Settlement Agreement was filed by PEC, Duke, the North Carolina Sustainable Energy Association (NCSEA), the North Carolina Pork Council (NCPC), the North Carolina Poultry Federation (NCPF), and the North Carolina Farm Bureau (NCFB). On August 6, 2012, the Commission issued an Order directing Duke and PEC to respond to certain questions relating to the proposed Settlement Agreement. Responses were filed by Duke and PEC on August 13, 2012.

On August 17, 2012, the Public Staff filed the testimony of Jay B. Lucas, Electric Engineer; Green Energy Solutions NV, Inc. (GES), filed the testimony of its President, Julian Cothran;[1] REI filed the testimony of Thomas McKittrick, President of Forsite Development, Inc.; and the Community Groups filed the testimony of Louis A. Zeller, Executive Director of the Blue Ridge Environmental Defense League.

On August 24, 2012, Duke filed the rebuttal testimony of witness Felt; DNCP filed the rebuttal testimony of witness Muchhala; NCEMPA and NCMPA1 filed the rebuttal testimony of witness Fusco; GreenCo filed the rebuttal testimony of witness Nemeth; NCSEA filed the rebuttal testimony of James D. Kennerly, its Policy and Regulatory Analyst; and NCPF filed the rebuttal testimony of Robert L. Ford, its Executive Director. The Commission also received several consumer statement of position letters from individuals in response to the Original Joint Motion and the Amended Joint Motion.

On August 28, 2012, the matter came on for hearing as scheduled. Duke and PEC presented the direct testimony of witness Ellis and the direct and rebuttal testimony of witness Felt; DNCP presented the direct and rebuttal testimony of witness Muchhala; TVA presented the direct testimony of witness DeHart; Fayetteville presented the direct testimony of witness Lynch; NCEMPA and NCMPA1 presented the direct and rebuttal testimony of witness Fusco; EnergyUnited presented the direct testimony of witness Natt; Halifax presented the direct testimony of witness Guerry; GreenCo presented the direct and rebuttal testimony of witness Nemeth; the Community Groups presented the direct testimony of witness Zeller; REI presented the direct testimony of witness McKittrick; the Public Staff presented the direct testimony of witness Lucas; NCSEA presented the rebuttal testimony of witness Kennerly; and NCPF presented the rebuttal testimony of witness Ford.

On September 7, 2012, Public Staff witness Lucas submitted late-filed exhibits. On September 12, 2012, REI witness McKittrick submitted late-filed exhibits.

On October 1, 2012, the Community Groups filed a post hearing brief. On October 9, 2012, Duke and PEC filed a Motion for Extension of Time to File Proposed Orders. On October 10, 2012, the Commission issued an Order Granting, In Part, Motion for Extension of Time to File Proposed Orders. On October 11, 2012, the NCPF filed a post hearing brief. On

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[1] The testimony of Julian Cothran on behalf of Green Energy Solutions NV, Inc. (GES), was prefiled on August 17, 2012, but, while GES was represented by counsel at the evidentiary hearing on August 28-29, 2012, no witness appeared on behalf of GES to sponsor the testimony and respond to cross examination. As a result, the Commission will treat this testimony as a statement of position.

October 19, 2012, the Public Staff; Fayetteville; Duke, PEC, EnergyUnited, GreenCo and Halifax collectively; REI; TVA; NCSEA; NCPC; DNCP; and NCEMPA and NCMPA1 collectively, filed post hearing briefs. Also on October 19, 2012, DNCP filed an affidavit of witness Muchhala.

Based on the foregoing, the evidence and exhibits filed by the parties, and the entire record in this proceeding, the Commission makes the following

FINDINGS OF FACT

1. The State's electric power suppliers have made a reasonable effort to comply with the swine waste set-aside requirement established by G.S. 62-133.8(e) and the poultry waste set-aside requirement established by G.S. 62-133.8(f) for 2012, but will not be able to comply.

2. Compliance with the set-aside requirements has been hindered by the fact that the technology of power production from swine and poultry waste is in its early stages of development.

3. Compliance with the poultry waste set-aside requirement has been hindered in some respects, and promoted in other respects, by the fact that on several occasions the General Assembly has modified the REPS, either through amending the statute or via session law. Legislative and regulatory developments have expanded the universe of compliance options for electric power suppliers.

4. Compliance with the swine and poultry waste set-aside requirements has been hindered by disagreements between electric power suppliers and renewable power developers over the terms and conditions of power purchase agreements; prolonged negotiations and continual changes in requested terms, formats of proposal, and bidding processes presented by the electric power suppliers; misunderstandings and disagreements between electric power suppliers and renewable power developers as to the procedures for interconnecting swine and poultry waste generation facilities with the electric grid, and as to the cost of such interconnection; and by the uncertainty of future applicable environmental regulations.

5. It is appropriate to delay the statutory deadlines of the set-aside requirements, not only for those electric power suppliers who have been unable to comply, but for all electric power suppliers.

6. Electric power suppliers who have acquired swine and poultry waste renewable energy certificates (RECs) for 2012 REPS compliance may bank such RECs for swine and poultry waste set-aside requirement compliance in future years.

7. Electric power suppliers should continue to make efforts to purchase any reasonably-priced swine and poultry waste RECs available in order to support the construction and operation of swine and poultry waste generation facilities and to fulfill requirements pursuant to this Order.

8. It is in the public interest to eliminate the requirement of G.S. 62-133.8(e) for compliance by the State's electric power suppliers with the swine waste set-aside requirement in 2012 and to delay for a one-year period the requirements of G.S. 62-133.8(f) for compliance by the State's electric power suppliers with the poultry waste set-aside requirement.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

The evidence supporting these findings of fact appears in the testimony of Duke-PEC witnesses Felt and Ellis, DNCP witness Muchhala, TVA witness DeHart, Fayetteville witness Lynch, Power Agencies witness Fusco, EU witness Natt, Halifax witness Guerry, GreenCo witness Nemeth, Community Groups witness Zeller, NCPF witness Ford, REI witness McKittrick, and Public Staff witness Lucas, and the statement of position of GES witness Cothran.

Duke-PEC witness Felt testified that Duke worked actively and diligently to comply with its swine waste set-aside requirements. Duke was a member of the Swine REC Buyers Group, and the group entered into seven contracts with swine waste power developers. The contracts were expected to fulfill the swine waste set-aside requirements for 2012 and 2013. Witness Felt and others testified that four of these contracts were terminated because the developers missed deadlines and failed to make progress toward commercial operation. The other contracts remain in effect, and, in addition, Duke has entered into two separate contracts with swine waste developers and has purchased a small number of RECs from a pilot-scale swine waste-to-energy project.

Witness Felt testified that Duke has also entered into three contracts with poultry waste developers, and that Duke expects to have some poultry and swine waste RECs by the end of 2013. According to witness Felt, among the problems Duke has faced in attempting to comply with the swine and poultry waste set-aside requirements are the technological difficulty of producing power from swine and poultry waste; the difficulty of developers to obtain financing for projects; the fact that projects are often located in remote rural areas and interconnection costs are high; difficulties in structuring contracts and balancing perceived risks between Duke and the developers; and uncertainty as to whether animal waste will be subject to the U.S. Environmental Protection Agency's (EPA) Commercial/Industrial Solid Waste Incinerator (CISWI) regulations. Witness Felt testified that Duke is hopeful that it can meet the current 2013 set-aside requirements, although Duke's compliance is dependent on how quickly negotiations can be completed and facilities come online. Additionally, witness Felt testified that potential compliance with the swine waste set-aside requirement in 2013 would be based in part upon a Duke biogas feasibility study, which has yet to be completed. She stated that Duke expects that it will be possible to meet the set-aside requirements in the years following 2013, but that this is also uncertain in view of the infancy of the animal waste generation industry.

Witness Felt also noted that there had been several legislative changes affecting the poultry waste set-aside requirement,[1] and while these changes had expanded the universe of compliance options for the electric power suppliers, they had also created uncertainty and required the electric power suppliers to continually re-evaluate their options for complying with the poultry waste set-aside requirement at the lowest cost. In addition, witness Felt testified that the potential for future changes in law regarding the REPS was a factor considered in negotiations with renewable energy developers. However, witness Felt testified that she was not aware of any additional proposed legislative changes, nor had she conferred with Duke's legislative liaison in regards to any potential changes.

Duke-PEC witness Ellis testified that PEC, like Duke, had worked diligently to meet the swine and poultry waste set-aside requirements. PEC participated with the other members of the Swine REC Buyers Group in signing contracts with several swine waste developers and subsequently terminating four of the contracts due to the developers' failure to make progress toward commercial operation. Unlike Duke, PEC also participated in the Poultry Collaborative, and the Collaborative entered into a contract with a developer to provide RECs for compliance with the poultry waste set-aside requirement. Witness Ellis testified that PEC is in negotiations with other parties for additional contracts for both swine and poultry power. When asked about the potential obstacles to full compliance with the swine and poultry waste set-aside requirements, witness Ellis emphasized the infancy of swine waste-to-energy technology and the need for a determination as to whether power generation from poultry waste is allowable under the CISWI regulations.

DNCP witness Muchhala testified that his company had participated in the Swine REC Buyers Group, entered into contracts with several swine waste developers, and terminated four of these contracts. Because of the contract terminations, DNCP undertook a nationwide search for developers who could supply swine waste RECs, but it was unable to obtain any swine waste RECs in North Carolina or any other state, and, therefore, it is unable to comply with the swine waste set-aside requirement in 2012. With respect to the poultry waste set-aside requirement, DNCP will be able to meet its own poultry waste set-aside requirement by buying out-of-state poultry waste RECs, as it is authorized to do under G.S. 62-133.8(b)(2)(e). For the purpose of meeting the poultry waste set-aside requirement of the Town of Windsor, a wholesale customer for which DNCP provides REPS compliance services, DNCP has chosen to participate in the Poultry Collaborative. Witness Muchhala testified that while DNCP is under contract with a developer to provide sufficient in-state RECs for future compliance with the poultry waste set-aside requirement, these RECs will not be available for compliance in 2012.

TVA witness DeHart testified that TVA is not a member of the Swine REC Buyers Group. TVA issued a request for offers of swine and poultry waste RECs in February 2012 and plans to issue a similar offer later this year. Witness DeHart stated that TVA plans to meet its customers' swine and poultry waste set-aside requirements through responses to this offer, through generators participating in its Generation Partners program or Renewable Standard Offer

[1] For example Session Law 2011-309 (Senate Bill 710) allowed thermal energy from poultry waste production to be eligible towards G.S. 62-133.8(f) compliance. Session Law 2012-195 (Senate Bill 886), modified a year later by Session Law 2011-279 (Senate Bill 484), made a limited amount of non poultry waste RECs eligible for G.S. 62-133.8(f) compliance purposes.

program, or through one or more stand-alone power purchase agreements with swine or poultry waste power producers.

Fayetteville witness Lynch testified confidentially concerning Fayetteville's efforts to comply with the swine and poultry waste set-aside requirements.

Power Agencies' witness Fusco testified that the Power Agencies were members of the Swine REC Buyers Group and, together with the other members, entered into contracts with several swine waste-to-energy developers, although some of these contracts subsequently had to be canceled. He further testified that the Power Agencies were initially members of the Poultry Collaborative. However, when the General Assembly passed Senate Bill 710, which allowed combined heat and power facilities, using poultry waste as a fuel to gain REC credit for the production of thermal energy produced as well as electric energy, the Power Agencies withdrew from the Poultry Collaborative and entered into a contract for poultry waste RECs with such a facility. Consequently, the Power Agencies are now in a position to comply with the poultry waste set-aside requirement for 2013, and NCMPA1 is in a position to comply for 2012 as well.

EU witness Natt testified that EU sought to obtain in-state swine and poultry waste RECs by participating in the Swine REC Buyers Group and the Poultry Collaborative. He stated that EU has entered into, and in some cases has had to cancel, the same contracts as other members of the group, and currently it has no in-state swine or poultry waste RECs. EU has, however, been able to acquire a limited number of out-of-state swine and poultry waste RECs.

Halifax witness Guerry testified that his cooperative had relied on the efforts of the Swine REC Buyers Group and the Poultry Collaborative to secure swine and poultry waste RECs. Witness Guerry testified that, at present, Halifax does not have any RECs derived from swine or poultry waste.

GreenCo witness Nemeth testified that GreenCo participated in the Swine REC Buyers Group and Poultry Collaborative, and it is also working to acquire swine waste RECs from two farms located in the service area of one of its member cooperatives, South River EMC. Witness Nemeth testified that GreenCo has also purchased out-of-state swine waste RECs, and it will consider issuing a request for proposals (RFP) for swine and poultry waste RECs. Witness Nemeth also testified about GreenCo's experience with GES. He stated that GES presented a proposal to supply poultry waste RECs to GreenCo in 2009, but that the proposal was unsatisfactory to GreenCo for several reasons. The proposal was for an industrial-scale project and would have produced far more RECs than GreenCo needed, and the proposal required GreenCo to buy all of GES's output. Witness Nemeth testified that GreenCo was also concerned because: (1) the GES project was located in South Carolina; (2) the GES project involved thermal as well as electric energy, at a time when the General Assembly had not passed legislation ensuring that thermal RECs would count toward the poultry waste set-aside requirement; and (3) there was uncertainty as to the project's costs. Witness Nemeth stated that GreenCo contacted GES to respond to its proposal. Witness Nemeth expressed strong disagreement with GES's contention that the electric power suppliers never intended to comply with the poultry waste set-aside requirement.

Community Groups witness Zeller testified that he is Executive Director of the Blue Ridge Environmental Defense League. He stated that he is opposed to the construction of biomass-fueled power plants because they increase atmospheric pollution, contribute to global warming, and involve such financial complexity that they cannot be effectively regulated by local government. In his opinion, the swine and poultry waste set-aside requirements should not be simply delayed for two years, but should be eliminated altogether. According to witness Zeller's testimony the Commission should report to the General Assembly that G.S. 62-133.8(e) and (f) are a "dead letter" and will never be met.

NCPF witness Ford testified concerning the importance of the poultry industry to the State's economy, the likelihood that land application of poultry litter as fertilizer will be restricted in the future, and the need to use litter for energy production if land application is limited. He stated that while the Commission has authority to delay and modify the application of G.S. 62-133.8(e) and (f), it does not have the authority to repeal them, and permanently excusing compliance with subdivisions (e) and (f) would have the effect of repealing them. He emphasized that the plants proposed by REI will not burn poultry waste, but instead will burn substitutes for poultry litter as authorized by Senate Bill 886, and he encouraged the Commission to approve the proposed Settlement Agreement entered into by NCPF, NCPC, NCFB, NCSEA, Duke, and PEC.

REI witness McKittrick testified that he is president of Forsite Development, Inc. (Forsite), an affiliate of REI. He stated that Forsite is the developer of Reventure Park in Mecklenburg County, a "cleanfields renewable energy demonstration park" as defined in Senate Bill 886, enacted by the General Assembly in 2010. Witness McKittrick stated that under Senate Bill 886, when one megawatt-hour of thermal or electric energy is generated from biomass (of any kind, not necessarily poultry waste) in a cleanfields renewable energy demonstration park, it will be eligible for a three times REC multiplier (one general REC creates an additional two poultry waste RECs.)[1] Witness McKittrick testified that REI is constructing a facility in ReVenture Park that will produce thermal and electric energy from biomass.[2]

Witness McKittrick stated that, when REI sought to enter into a contract to sell its RECs to Duke, Duke insisted that the contract include a "change of law" provision under which the risk of changes in the renewable energy statutes would be placed on REI. He stated that REI's lenders would not approve a contract with such a provision, and the negotiations broke down. In witness McKittrick's view, the market for poultry waste RECs cannot develop properly, and the poultry waste set-aside requirement cannot function successfully, unless electric power suppliers are willing to agree to a reasonable share of the risk of change of law and other risks inherent in a business transaction. Witness McKittrick further testified that REI is willing to sell its RECs of vintage 2013 to electric power suppliers, and the Commission should not take away this business

[1] Reventure Park Investments I, LLC, filed a request for a declaratory ruling on March 15, 2011, regarding the Commission's interpretation of SB 886 and how the REC provisions of the Act would be implemented. The Commission issued an Order on the request on April 18, 2011.

[2] REI filed a report of proposed construction for the facility on June 25, 2012, in Docket No. SP-1927, Sub 0, and a registration statement as a new renewable energy facility on September 24, 2012, in Docket No. SP-1927, Sub 1.

opportunity by relieving the electric power suppliers from their obligation to meet the poultry waste set-aside requirement in 2013.

REI witness McKittrick testified that the relief sought by the Amended Joint Motion and the Settlement Agreement could put many projects in limbo, including those of REI. He testified that the interest of several electric power suppliers in purchasing poultry waste RECs is dependent on the outcome of this docket. He further stated that REI fears that if the Commission modifies the poultry waste set-aside requirements, potential purchasers will wait until after the next legislative session before deciding to purchase RECs, and if they do, REI will likely not construct one of its two proposed facilities.

According to the statement of position of GES president Cothran, GES has completed construction of a plant in South Carolina that will produce electric and thermal energy from poultry waste. Cothran asserted that GES attempted to market its RECs to several electric power suppliers, but that none were willing to negotiate with GES except for Duke. According to Cothran's statement, Duke took such demanding and unreasonable negotiating positions that the negotiation of the contract took more than 24 months. At present, construction of the plant is complete and the facility is generating biogas from poultry waste, but the plant cannot be connected to the grid because of disputes among GES, Duke, and PEC as to the amount of the interconnection charges and who is responsible for the charges.

Public Staff witness Lucas testified that EPA regulations, in particular the proposed CISWI regulations, have made compliance with the swine and poultry waste set-aside requirements difficult; however, a poultry waste facility proposed by Prestage Farms, Inc., has obtained a determination by the Division of Air Quality of the North Carolina Department of Environment and Natural Resources that its fuel source will be considered a non-solid waste fuel and thus not subject to CISWI. Witness Lucas further stated that two recurring issues have presented difficulty for swine and poultry waste developers seeking to reach agreement with electric power suppliers for the purchase of their RECs: (1) differences in agreement over contract terms, particularly "change of law" provisions, and (2) inability to reach a satisfactory interconnection agreement. Additionally, witness Lucas testified that the Public Staff believes it is reasonable for a utility to negotiate with the expectation that current law and current statutory requirements will remain in place, unless it has verifiable information indicating otherwise.

The Commission has reviewed all of the evidence and concludes the electric power suppliers have demonstrated that they made a reasonable effort to comply with the swine and poultry waste set-aside requirements for 2012. The electric power suppliers invested both time and effort to (1) solicit proposals for generation from swine and poultry waste, (2) evaluate the proposals received, (3) negotiate contracts with the developers who presented the most promising proposals, and (4) monitor the developers' performance under their contracts. No evidence was presented to suggest that the electric power suppliers failed to make a reasonable effort to comply, except for the testimony of REI witness McKittrick that Duke's contract negotiating position was inflexible. Although the statement of position of GES president Cothran indicates that he received no response to some of his proposals, the record shows that his company did ultimately enter into a contract with Duke. As for witness McKittrick, credible witnesses testified that Duke devoted a great deal of time to negotiating with his company, even though the two companies did not ultimately reach agreement on a contract.

Nonetheless, the Commission acknowledges the concerns raised by REI and GES that difficult negotiations, slow or inconsistent responses, interconnection issues, and shifts in position due to changes in law may, in some cases, have delayed progress toward compliance with the swine and poultry waste set-aside requirements. Therefore, similar to the stipulations agreed to in the proposed Settlement Agreement entered into by NCPF, NCPC, NCFB, NCSEA, Duke, and PEC, the Commission will require heightened reporting requirements and improvements in communications between electric power suppliers and developers, including a triannual report to the Commission and a website Information Sheet, in order to help reduce similar delays in the future.

Numerous witnesses testified that the most substantial reason for the electric power suppliers' failure to comply with the set-aside requirements is the immaturity of the animal waste power production industry and its technology. As Duke-PEC witness Felt testified, "producing electricity from swine waste is technologically challenging and few successful applications exist." Witnesses testified that the same is true of poultry waste technology. In essence, when the General Assembly enacted G.S. 62-133.8(e) and (f), it was seeking to advance the development of an industry that was in its infancy. In the initial development stages of a new industry, such setbacks and failures are not unexpected.

Another factor contributing to the electric power suppliers' failure to achieve compliance with the swine and poultry waste set-aside requirements is the applicability of environmental regulations. Public Staff witness Lucas testified that it is uncertain whether EPA's proposed CISWI regulations will apply to facilities that generate electricity from animal waste. The Commission finds that uncertainty may discourage potential bidders from responding to the electric power suppliers' requests for proposals.

The General Assembly amended G.S. 62-133.8(f), the statutory provision for the poultry waste set-aside requirement, on three occasions in 2010 and 2011. In Senate Bill 886, enacted on August 5, 2010, the General Assembly authorized triple credit for RECs produced from biomass at a "cleanfields renewable energy demonstration park," with each megawatt-hour produced at such a facility counting as one general REC that upon retirement additionally will count as two poultry waste RECs, even if the facility's generation source is some form of biomass other than poultry waste. In Senate Bill 484, enacted on June 23, 2011, the triple REC credit for a facility at a cleanfields renewable energy demonstration park was limited to the first 10 megawatts of capacity at such a facility. Senate Bill 710, enacted on June 27, 2011, provides that thermal as well as electric energy produced from poultry waste is eligible for poultry waste RECs. With the enactment of each statutory change, the process of contracting for poultry waste RECs was delayed, as electric power suppliers reanalyzed the proposals they had received and determined which was lowest in cost. However, as witness Lucas and others testified, the overall effect of the statutory changes was to make more facilities eligible for poultry waste RECs and, thus, to lower the price of poultry waste RECs.

Another factor that has made it more difficult for the electric power suppliers to comply with the swine and poultry waste set-aside requirements involves differences between the electric power suppliers and swine and poultry waste developers as to the terms and conditions of purchase agreements. There was extensive testimony about the negotiations between Duke and REI concerning their proposed contract. These negotiations continued for several years and did not result in agreement, with the main area of dispute relating to Duke's proposed language on change of law. Public Staff witness Lucas testified that change of law and interconnection are recurring issues that make it difficult for electric power suppliers to reach agreement with developers, and, thus, for them to reach compliance with the swine and poultry waste set-aside requirements. The Commission agrees with witness Lucas's testimony that it is reasonable for an electric power supplier to negotiate with the expectations that current statutory requirements will remain in place, unless it has verifiable information indicating otherwise. Additionally, the Commission finds that it would be reasonable for a public utility to negotiate with the expectation that it would have a reasonable opportunity to recover prudent costs resulting from contracts entered to satisfy existing law at the time of a contract's creation.

The Commission concludes that the electric power suppliers have made a reasonable effort to comply with the swine and poultry waste set-aside requirements in 2012. While some electric power suppliers have been able to make some progress towards their compliance with the poultry waste set-aside requirement, the vast majority of them will not be able to comply successfully with either of the set-aside requirements in 2012. The primary reason for the suppliers' failure to comply is the newly developing and still unproven state of the technology for generating power from animal waste. Other reasons include (1) the uncertainty surrounding environmental regulation of the newly developing industry; (2) frequent changes in legislation relating to the poultry waste set-aside requirement; (3) prolonged negotiations and changing requests for proposals and buying groups; (4) difficulties in reaching agreement on contract terms and conditions, particularly with respect to change of law and interconnection; and (5) the lack of experience of some swine and poultry waste developers. Overall, the Commission concludes that substantial progress is being made, but at a pace that is somewhat slower than what the General Assembly envisioned.

While compliance in 2012 is not possible, at this time the Commission feels it is premature to make a similar finding for 2013. A small number of the electric power suppliers are already in position to comply with the 2013 set-aside requirements. Additionally, this Order will greatly reduce the pro-rata poultry waste set-aside requirements in 2013 for each electric power supplier (a pro-rata portion of 170,000 MWh rather than 700,000 MWh). Duke witness Felt testified that she was hopeful Duke could meet the original 2013 requirement, a requirement significantly larger than the 2013 requirement resulting from this Order, and that Duke still awaits the results of its biogas feasibility study. Legislative changes have expanded the means of compliance with the poultry waste set-aside requirement and an additional year may yield results that allow electric power suppliers to comply with the updated schedule in 2013 pursuant to this Order. Additionally, the evidence has shown that swine and poultry waste facilities are part of an ever changing market; the Commission is not in a place to anticipate changes to the market over the next year. Further, the Commission hopes to support the General Assembly's intent to facilitate near-term development of poultry and swine waste generation. As North Carolina is the only state in the country with specific REPS set-aside requirements for energy generated from animal waste, a prolonged delay could have pronounced implications on the developing markets for these RECs.

When exercising the "off ramp" authority granted to the Commission in G.S. 62-133.8(i)(2), the Commission does so with constraint and an attempt to preserve as much of the intent of the General Assembly as possible. At this time it appears premature to make a finding that the electric power suppliers have made a reasonable effort to comply with the swine and poultry waste set-aside requirements for 2013, and that a two-year delay is in the public interest. The electric power suppliers should continue to make reasonable efforts to comply with the 2013 requirements as modified pursuant to this Order. However, nothing in this Order shall preclude the electric power suppliers from making a similar motion at a later date demonstrating that they cannot achieve compliance and have made a reasonable effort to do so in 2013, if circumstances warrant such action.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-7

The evidence supporting these findings of fact appears in the testimony of DNCP witness Muchhala and Power Agencies witness Fusco.

DNCP witness Muchhala testified that DNCP initially planned to participate in the Poultry Collaborative to meet its poultry waste set-aside requirements, but based on legislative and regulatory developments, as well as the growing availability of RECs in other states, DNCP limited its continued participation in the Poultry Collaborative to obtaining in-state poultry waste RECs for the Town of Windsor, a wholesale customer for which DNCP is providing REPS compliance services. For its own use, DNCP sought to purchase additional poultry waste RECs from out-of-state. As a result, DNCP has been able to make significant progress towards its 2012 poultry waste set-aside requirements through the purchase of out-of-state RECs, but it remains unable to meet the in-state needs of the Town of Windsor. [1]

DNCP witness Muchhala further testified that, as a result of DNCP's initial efforts to obtain swine waste RECs, it learned that swine waste-to-energy technology is relatively new and that a market for swine waste RECs has not developed yet. As a result, DNCP concluded that participating in the Swine REC Buyers Group was the most cost effective and prudent approach. DNCP is an active participant in the group's efforts, but as a result of the termination of several contracts originally entered into by the Swine REC Buyers Group, DNCP has conducted its own independent search for swine waste RECs in the State and across the nation. Despite its ability to use RECs derived from out-of-state facilities, DNCP has not been able to obtain or even identify sufficient quantities of swine waste RECs on a nationwide basis to meet its statutory requirements. To the extent that DNCP has been able to comply, it requests that the Commission allow it to bank the animal waste RECs it has already obtained to be used for compliance in future years, rather than retire them in 2012. DNCP states that to do otherwise would result in its being penalized for its good faith efforts to comply.

Power Agency witness Fusco testified that NCMPA1 has been able to secure sufficient poultry waste RECs to meet its 2012 requirements and that both Power Agencies anticipate being

[1] The Commission's September 22, 2009, Order in this docket on DNCP's Motion for Further Clarification clarified that G.S. 62-133.8(b)(2)e expressly exempts DNCP from the 25% limitation on the use of unbundled out-of-state RECs. DNCP provides REPS compliance services for the Town of Windsor, an electric power supplier that is a wholesale customer of the Company, and Windsor is not exempt from the 25% limitation.

in a position to comply with the 2013 poultry waste set-aside requirement. Rather than requiring NCMPA1 to retire the 2012 poultry waste RECs it has obtained, witness Fusco requested that the Commission allow them to be banked for compliance in future obligation years. Witness Fusco stated that the Power Agencies agreed to be party to the Joint Motion because the set-aside requirements are statewide and industry-wide aggregate requirements. He further stated that any relief granted to any electric power supplier should be applied equitably to all electric power suppliers. In his opinion, suppliers that have diligently pursued efforts to comply, and have secured RECs, should not be punished for having done so by being denied the relief granted to those that could not comply and not being allowed to bank the RECs they have secured. Witness Fusco also testified that not allowing the banking of RECs could send a message to the marketplace that would potentially hinder future compliance. As an example, witness Fusco pointed out that if the Commission granted a delay, but then required those electric power suppliers who had acquired RECs to retire them, then an electric power supplier "may opt to negotiate with a supplier to delay delivery of those RECs until 2014 and, hence, avoid the additional cost of having to comply twice with the requirement that really doesn't take effect until 2014."

The Commission commends those electric power suppliers that have acquired sufficient poultry and/or swine waste RECs such that they could meet their 2012 poultry or swine waste set-aside requirements. The Commission is not persuaded that it would be punitive to require compliance by those electric power suppliers that can, in fact, comply. However, the Commission is concerned that some electric power suppliers might have purchased swine waste RECs that will eventually be determined to be ineligible for compliance.[1] In addition, the Commission recognizes that the General Assembly established the swine and poultry waste set-aside requirements as aggregate obligations and imposed them on all North Carolina electric power suppliers together. Notwithstanding prior Commission Orders approving compliance based on pro-rata shares of the aggregate requirements, the Commission finds that it is in the public interest that all electric power suppliers currently be held to the same compliance schedule for the swine and poultry waste set-aside requirements.

On February 29, 2008, the Commission issued an Order Adopting Final Rules to Implement S.L. 2007-397 in this docket. In that Order the Commission considered the wording of the statutory off-ramp provision and questions about whether the off-ramp should be applied to all electric power suppliers or only to those individual electric power suppliers that demonstrated a need. The Public Staff, SunEdison, and the Solar Alliance all recommended that in a situation where a limited number of suppliers have shown the need for a modification or delay of the REPS requirement, the proper course of action for the Commission to take is to grant the modification or delay solely with respect to those suppliers that need it. The Commission agreed with this position and ultimately included in Rule R8-67(c)(5) the following sentence: "The Commission shall allow a modification or delay only with respect to the electric power supplier or group of electric power suppliers for which a need for a modification or delay has been demonstrated." The situation envisioned by the Public Staff, SunEdison, and the Solar Alliance is different than the one currently faced by the Commission, however, where the vast majority of the electric power suppliers are unable to comply despite their reasonable efforts. In

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[1] See the Commission's August 10, 2012 Order Requesting Audit and Recommendations in Docket No. SP-813, Sub 0.

this matter the "group of electric power suppliers for which a need" has been demonstrated is all electric power suppliers due to the aggregate nature of the swine and poultry waste set-aside requirements, the small number of electric power suppliers that can show even partial compliance, and the disincentive for future compliance were the Commission to rule otherwise

On March 31, 2010, the Commission issued an Order on Pro Rata Allocation of Aggregate Swine and Poultry Waste Set-Aside Requirements and Motion for Clarification in this docket. The Order approved a proposed pro-rata mechanism for electric power suppliers to demonstrate compliance with the swine and poultry waste set-aside requirements. Nothing in the Order, however, changed the requirements from aggregate requirements as established by the General Assembly. Under the current circumstances, to delay the requirements only for a portion of the electric power suppliers while requiring a small number of others to comply with their pro-rata portion would cause unnecessary future confusion in compliance as different electric power suppliers would be on different compliance schedules for aggregate requirements.

While G.S. 62-133.8(i)(2) requires an electric power supplier to demonstrate that it made a reasonable effort to meet the requirements, the Commission's authority to modify or delay the REPS requirements is based on the Commission's determination that it is in the public interest to do so. The Commission finds in this case that the public interest would be best served by allowing the efforts of the electric power suppliers to be considered as a whole, and that the delay should also be applied equally to all electric power suppliers. Electric power suppliers that have obtained RECs to meet some portion of their poultry or swine waste set-aside requirements should bank those RECs for compliance in 2013 and continue acquiring RECs for future compliance.

The Commission cautions, however, that if an electric power supplier is individually found not to have made reasonable efforts over the period of the delay to meet its compliance obligations, such a supplier may find the Commission less willing in future proceedings to treat it comparably to others who clearly demonstrated reasonable efforts. While not attempting to define what constitutes reasonableness, the Commission may consider the following actions as illustrative of the reasonableness of the electric power supplier's efforts: (1) issuing RFPs for qualifying resources; (2) consideration of self-build options; (3) expenditure of research and development funds to evaluate swine and poultry waste-to-energy technologies; (4) outreach efforts to poultry and swine waste power producers; (5) exploration of out-of-state markets, when permitted; (6) negotiations with developers; (7) good faith efforts to negotiate power and REC purchase contracts; and (8) good faith efforts to assist developers with interconnection agreements and place their facilities in service in a timely fashion. The Commission notes that some of these efforts are included as part of the conditions of this Order and recognizes them as solid steps in making further progress in these areas.

Despite the granting of the delay and allowing for the banking of RECs in this Order, the Commission has ongoing concerns regarding the ability of the electric power suppliers to comply in 2013 and future years based on existing contracts and estimates for facilities under construction. To the extent that electric power suppliers are able to identify reasonably priced, technologically viable options for compliance that can be placed in service in 2012, the Commission encourages them to give those options full consideration.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The Commission's authority to modify or delay the REPS requirements is based on the Commission's determination that it is in the public interest to do so. When establishing the REPS in Session Law 2007-397 the General Assembly set forth goals of the REPS which were "declared to be the policy of the State of North Carolina." Specifically G.S. 62-2(a)(1) stated that the development of renewable energy and energy efficiency through the implementation of a REPS will:

a. Diversify the resources used to reliably meet the energy needs of consumers in the State.
b. Provide greater energy security through the use of indigenous energy resources available within the State.
c. Encourage private investment in renewable energy and energy efficiency.
d. Provide improved air quality and other benefits to energy consumers and citizens of the State.

Based on testimony in this proceeding, the market for poultry and swine waste-to-energy projects is clearly in its infancy. The lack of sufficient projects has made the poultry and swine waste set-aside requirements much more costly than other options for meeting the general REPS requirement. These costs are eventually borne by retail consumers, and allowing more time for the market to develop is in the public interest in that it will protect customers from the inflated cost of an undeveloped industry. A one-year delay will not further deter private investment in the market. Additionally, several environmental and public health concerns, including air quality concerns, in regard to the production of electricity from poultry and swine waste were expressed in witness Zeller's testimony for the Community Groups and also submitted to the Commission in several consumer statement of position letters. A delay may allow for improvements in these areas and alleviate some concerns as the industry advances technologically, allowing for advances in areas such as anaerobic digestion and emission reductions, which may allow poultry and swine waste to become a cleaner source of energy in the future. During a delay the applicability of the CISWI regulations might also be clarified which could provide certainty to both financiers and environmental groups as to the state of regulation regarding swine and poultry waste-to-energy facilities. These developments would better allow the REPS to achieve its stated goal and policy to "[p]rovide improved air quality and other benefits to energy consumers and citizens of the State."

Based on all of the forgoing evidence and conclusions, the Commission finds that the electric power suppliers sufficiently demonstrated that they have made reasonable efforts to meet the swine and poultry waste set-aside requirements in 2012, and that eliminating the 2012 swine waste set-aside requirement of G.S. 62-133.8(e) and delaying the poultry waste set-aside requirement of G.S. 62-133.8(f) for 2012, as provided for in this Order, is in the public interest.

IT IS, THEREFORE, ORDERED as follows:

1. That the 2012 requirement of G.S. 62-133.8(e) shall be eliminated. The electric power suppliers, in the aggregate, shall comply with the requirements of G.S. 62 133.8(e) according to the following schedule:

Calendar Year	Requirement for Swine Waste Resources
2013-2014	0.07%
2015-2017	0.14%
2018 and thereafter	0.20%

2. That the effective date of G.S. 62-133.8(f) shall be delayed for one year. The electric power suppliers, in the aggregate, shall comply with the requirements of G.S. 62-133.8(f) according to the following schedule:

Calendar Year	Requirement for Poultry Waste Resources
2013	170,000 megawatt hours
2014	700,000 megawatt hours
2015 and thereafter	900,000 megawatt hours

3. That the general REPS requirements established in G.S. 62-133.8(b) and (c) shall remain unchanged as a result of this Order.

4. That Duke and PEC shall file triannual progress reports verified by an Officer of each company (Progress Reports) to the Commission, providing an up to date summary and position of Duke's and PEC's compliance with, and efforts to comply with, G.S. 62-133.8(e) and (f). The Progress Reports shall be filed on or before January 1, May 1, and September 1 of each fiscal year. The final Poultry Waste Set-Aside Progress Reports shall be made September 1, 2014, and the final Swine Waste Set-Aside Progress Reports shall be made September 1, 2018. The Progress Reports shall be provided to the Public Staff and other interested parties, subject to existing nondisclosure agreements, and shall be filed with the Commission under seal. The Progress Reports shall, without limitation, include: (a) an overall summary of Duke's and PEC's respective current compliance provisions; (b) a list of all entities that Duke and PEC have engaged in discussions about contracts for compliance with the swine and poultry waste set-aside requirements; (c) a list of and summary of relevant options and active proposals that Duke and PEC have received for compliance with the swine and poultry waste set-aside requirements and who provided them; (d) a list of all entities that Duke and PEC have contracted with for swine or poultry waste generation or RECs and a summary of the contracts; (e) for each entity listed in items (b) and/or (c) above that Duke and PEC have not contracted with, a summary of reasons why a contract has not been executed; (f) a summary of Duke's and PEC's respective plans to procure contracts for compliance with the swine and poultry waste set-aside requirements in the next four months; (g) for any plans to procure contracts for compliance with the swine and poultry waste set-aside requirements from the preceding four months that were not implemented, a summary of why they were not implemented; and (h) a statement about Duke's and PEC's respective forecasts and plans to comply with the swine and poultry waste set-aside requirements by the statutory deadlines as amended by this Order. Duke and PEC shall also file with the

Commission and provide to the Public Staff notification of any material changes that have occurred since the last Progress Reports, including delays in commercial operation date of any facilities under contract, termination of any existing contracts, or any significant modification of capacity or technology by an existing project developer that is under contract with them. The Commission reserves the right to request similar information from other electric power suppliers. The Progress Reports shall be filed in a new docket, Docket No. E-100, Sub 113A.

5. That within 45 days of the issuance of this Order, Duke and PEC shall create a web-based summary Information Sheet designed to inform developers of swine or poultry waste-to-energy facilities (waste-to-energy facilities) of the following, at a minimum: (a) typical fees, charges, terms and contract conditions associated with power purchase agreements used by Duke and PEC for the acquisition of electricity and RECs (bundled or unbundled) from waste-to-energy facilities; (b) the requirements for interconnecting an electric generation facility with Duke's and PEC's transmission or distribution systems, highlighting any unique features that may apply to remotely located facilities; (c) the identification and a brief description of considerations or difficulties that Duke and PEC have observed as being an impediment to developers of waste-to-energy facilities seeking to build and operate a facility and sell the output (bundled or unbundled) to electric power suppliers in North Carolina; (d) contact information for appropriate personnel regarding power purchase agreements; (e) contact information for appropriate personnel regarding interconnection agreements for facilities proposed to be located in the respective utility's service territory; and (f) information on any open RFPs and links on the web-based portal to any current applicable RFPs. PEC and Duke shall file a copy of their most recent Information Sheet in Docket No. E-100, Sub 113A. Parties may disseminate hard copies of the Information Sheet to developers of waste-to-energy facilities. Electric power suppliers other than PEC and Duke shall be required to provide the information specified in subparagraphs (d) through (f) above for use in the Information Sheet. Any electric power supplier other than Duke or PEC that submits to Duke or PEC a written request to do so shall be allowed by Duke and PEC to participate in the design and preparation of the Information Sheet. A draft of the Information Sheet shall be circulated to parties to this docket within 30 days from the date of this Order and those persons may provide Duke and PEC comments on the content of the Information Sheet not later than 10 days following receipt. The web-based Information Sheet shall be updated as necessary.

6. That the electric power suppliers may bank any poultry or swine waste RECs acquired prior to 2013 for retirement and REPS compliance in years 2013 and beyond.

7. That each of the electric power suppliers shall continue to take all reasonable actions to purchase all available and reasonably priced swine and poultry waste RECs.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of November, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Dc112912.01

DOCKET NO. E-100, SUB 126

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Investigation of Integrated Resource Planning in North Carolina – Smart Grid Technology Plans	)))	ORDER AMENDING COMMISSION RULE R8-60 AND ADOPTING COMMISSION RULE R8-60.1

BY THE COMMISSION: On December 28, 2009, after having considered and declined to adopt a federal smart grid standard in Docket No. E-100, Sub 123,[1] the Commission issued an Order in the above-captioned docket requesting comments on a proposed amendment to Commission Rule R8-60, Integrated Resource Planning and Filings, which would require investor-owned utilities (IOUs) to include a description of their smart grid technology plans as part of their biennial integrated resource plan (IRP) filing. In that Order, the Commission made all parties of record in Docket No. E-100, Sub 124 parties to this docket. Further, the Commission allowed other interested parties to intervene and scheduled presentations by the State's IOUs of their smart grid technology plans for January 26, 2010.

On December 30, 2009, the North Carolina Attorney General filed his notice of intervention.

On January 26, 2010, Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC); Duke Energy Carolinas, LLC (Duke); and Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP), appeared before the Commission to present their smart grid technology plans, as scheduled.

On February 26, 2010, comments on the proposed amendment to Rule R8-60 were filed by Duke and DNCP, jointly, the North Carolina Sustainable Energy Association (NCSEA), and the Public Staff.

On March 3, 2010, NCSEA filed a motion for leave to file supplemental comments.

On March 8, 2010, and March 9, 2010, respectively, PEC and Duke filed motions requesting the opportunity for parties to file reply comments. By Order issued March 11, 2010, the Commission granted all parties an opportunity to file reply comments.

[1] Sections 532 and 1307 of the Energy Independence and Security Act of 2007, Pub. L. 110-140 (EISA) amended section 111 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 2621, requiring each state regulatory authority, with respect to each electric utility for which it has ratemaking authority, to consider new federal standards and to determine whether or not implementing such standards were appropriate for carrying out the purposes of PURPA. Section 532 of EISA amended PURPA by adding sections 111(d)(16)-(17): (16) Integrated resource planning; (17) Rate design modifications to promote energy efficiency as a priority resource. Section 1307 of EISA amended PURPA by adding sections 111(d)(18)-(19): (18) Consideration of smart grid investments; (19) Smart grid information.

On March 26, 2010, joint reply comments on the proposed amendment to Rule R8-60 were filed by Duke, DNCP and PEC, and separate reply comments were filed by the Public Staff.

COMMENTS AND PROPOSED AMENDMENTS OF THE PARTIES

DUKE/DNCP

In their joint comments, Duke and DNCP agreed with the concept of the Commission's proposed amendment, noting that they believe the potential impacts of a utility's smart grid plans should be incorporated in the IRP process. However, Duke and DNCP expressed concern with the level of detail proposed in the amendment. Specifically, Duke and DNCP contended that restructuring the proposed amendment to focus on an overview of a utility's smart grid program was better aligned with their understanding of the intent of the IRP process, a focus on resource planning and load forecasting. Further, Duke and DNCP believe that the Commission's proposed amendment of Rule R8-60 is more consistent with the requirements of a certificate of public convenience and necessity (CPCN) or a petition for approval of an energy efficiency (EE) program or demand-side management (DSM) program, as opposed to the IRP process. Additionally, Duke and DNCP argued that utilities would be unnecessarily burdened to provide details for smart grid plans that are not fully developed and subject to frequent change. Duke and DNCP stated that, if the Commission's proposed amendment of Rule R8-60 is not revised to reflect an overview of a utility's smart grid plans, the appropriate procedural action would be for the Commission to adopt a stand-alone docket to address the details of a utility's smart grid plans. Finally, Duke and DNCP's recommended amendments that reflect their views regarding the purpose of including smart grid plans in the IRP filing.

NCSEA

In its comments, NCSEA concurred with the Commission's recommendation to incorporate smart grid technology plans in the IRP process. Specifically, NCSEA believes that including smart grid technology plans in the IRP process would expose technology investments in smart grid to new levels of transparency and scrutiny, thus potentially resulting in more thorough and tighter smart grid plans. Subject to the technological improvements and evolving nature of smart grid technology, NCSEA emphasized that smart grid investments may not always be superior to standard technologies. Additionally, NCSEA believes that inclusion of smart grid plans in the vetting requirements of the IRP process may work to address issues related to stranded investment and least-cost resource mix.

While concurring with the proposed amendment of Rule R8-60, NCSEA noted multiple areas of concern. First, NCSEA recommended that the term "two-way communication" be incorporated in the definition of smart grid technologies because it believes that this is an essential characteristic of smart grid technologies. Second, NCSEA recommended expanding the information requested for smart grid technology plans to include details related to the utility's goals and/or objectives, consistent with the proposed technology to be utilized. Third, NCSEA recommended that the proposed amendment include a comparative analysis of the proposed technologies and other technologies available to meet the goals and/or objectives defined in a utility's smart grid plans. Fourth, NCSEA recommended that an analysis be included to demonstrate and ensure the interoperability of proposed technologies and respective legacy systems. Finally, NCSEA proposed amendments that reflect its views regarding the purpose of including smart grid plans in the IRP filings.

PUBLIC STAFF

In its comments, the Public Staff also noted multiple areas of concern. First, the Public Staff stated that the proposed amendment only addresses the State's IOUs and that it should encompass all entities subject to the IRP process, including electric membership corporations. Thus, to the extent that such information is available, North Carolina Electric Membership Corporations (NCEMC) and any individual electric membership corporation (EMC) subject to the IRP Rule, Rule R8-60, should provide smart grid information. Second, the Public Staff recommended that the Commission enhance the proposed amendment to include a description of the smart grid technologies that each electric utility is planning to install. The Public Staff further recommended that the description of the smart grid technologies be aligned with the Commission's description of smart grid technologies and incorporate a current and five-year outlook for the technologies being installed. The Public Staff believes that such an enhancement would be more consistent with the timeframe of the fifteen-year native load forecast currently required in the IRP process. Third, the Public Staff objected to the inclusion of cost recovery details associated with smart grid technology plans, stating that the IRP is not a cost recovery proceeding and that the inclusion of such information may impact ratemaking and cost recovery proceedings currently established by G.S. 62-133.

The Public Staff agreed with the Commission's proposed amendment requiring the inclusion of customer impacts for smart grid technologies, by class, as part of the smart grid technology plans. However, the Public Staff stated that inclusion of customer impacts should also be described on a system, retail jurisdictional, and retail customer class basis, along with respective measurement and verification plans. The Public Staff also agreed with the Commission's proposal to include: (1) capital expenditures associated with smart grid technologies, (2) a cost benefit analysis for smart grid technologies, and (3) a description of existing equipment to be rendered obsolete (if any), and documentation of its anticipated book value, along with its salvage life. Further, the Public Staff concurred with the Commission's proposal regarding the detail of pilots and government or grant-funded initiatives. Finally, the Public Staff recommended that details addressing the privacy and security of customer information should also be included.

SUPPLEMENTAL COMMENTS OF NCSEA

In its supplemental comments, NCSEA reiterated its concurrence with the Commission's recommendation for inclusion of smart grid technology plans in the IRP process. NCSEA understands that the IRP represents an electric utility's statement of anticipated consumer demand and an explanation as to how those needs will be met – it is essentially a resource planning tool. Further, NCSEA believes that inclusion of smart grid plans in the IRP process should be as thorough and complete as possible, ultimately providing a clear understanding of how smart grid technologies are being utilized and what relevant benefits are derived from its utilization.

Specifically, NCSEA recommended that the Commission consider incorporating, in part or whole, the following:

1. A description of installations that could be either “smart” or “conventional” and an explanation for the choice made;

2. A description of transmission, distribution, and generation projects deferred due to the smart grid projects adopted or to be adopted;

3. A description of how proposed smart grid projects will improve reliability and security of the grid;

4. An estimate of greenhouse gas (GHG) emissions offset by the installation of smart grid technology and estimates of renewable energy credits earned via reductions in generation from the implementation of the smart grid technology;

5. The percentage reduction in output occurring at non-baseload generating facilities than can be attributed to the implementation of smart grid technologies and, if possible, a breakdown by technology;

6. A description of societal benefits that are or can be attributed to smart grid technology; and

7. A description of non-utility investments in the electric grid that can be attributed to smart grid technology investments.

REPLY COMMENTS OF THE PARTIES

<u>DUKE / DNCP / PEC</u>

In their joint initial comments, Duke and DNCP agreed with the Commission’s proposed amendment, but only in concept. In their reply comments, Duke and DNCP raised areas of concern and recommended that the Commission adopt a stand-alone docket to address the details of smart grid technology plans, subject to their understanding of the intent of the IRP and the level of detail proposed by the Commission for smart grid technology plans. Inasmuch as PEC initially reserved comment on the Commission’s proposed amendment, PEC now joined with Duke and DNCP in their initial recommendations.

In their joint reply comments, Duke, DNCP and PEC stated that their understanding of the purpose of the IRP process is to aid “the Commission with its analysis of long-range needs for the expansion of facilities for the generation of electricity in North Carolina”. Further, Duke, DNCP and PEC stated that the energy forecast, demand requirements, and impacts of DSM and EE programs to load forecast and resource requirements are inherent to the Commission’s IRP analysis. With regard to the impacts on load forecast and resource requirements, the companies emphasized that not all smart grid initiatives may result in load improvements. Rather, some may improve grid operations, system reliability, or, in some cases, enable DSM/EE programs.

Duke, DNCP and PEC agreed with the Public Staff's recommendation to exclude cost recovery plans associated with smart grid technology plans. Further, the utilities argued that the requirements proposed by NCSEA are too broad in scope and ill-defined, potentially resulting in no value-added benefit, an inefficient utilization of resources, and, in some cases, pursuit of information not available to an electric utility. Duke and DNCP concluded by reiterating their initial comments, with which PEC now concurs, that they believe it is more appropriate for the proposed amendment of Rule R8-60 to be focused on an overview of a utility's smart grid program, its deployment of that program, and the demand and energy impacts of program deployment, while reserving any smart grid program details for consideration in a separate docket.

PUBLIC STAFF

In its reply comments, the Public Staff provided both its revised recommendation for the Commission's proposed amendment to Rule R8-60 and its proposal for the adoption of an additional smart grid rule, Rule R8-60.1, to address details regarding a utility's smart grid technology plans. In its revised recommendation, the Public Staff concurred with Duke, DNCP and PEC that the focus of the proposed amendment should be revised to emphasize the impacts of smart grid technology on resource planning and load forecasting, as opposed to the details of a smart grid technology plan. However, the Public Staff cited differences between its proposed amendment and Duke, DNCP and PEC's proposed revision. Specifically, the Public Staff stated that the description of the impacts of the smart grid technology should include a description of the technology producing the impacts. The Public Staff acknowledged that smart grid technologies are evolving and that levels of uncertainty may exist. However, the Public Staff cited PEC's January 26, 2010, smart grid presentation before the Commission and its inclusion of a "roadmap" for PEC's smart grid strategy beyond 2013. Thus, the Public Staff reiterated its initial recommendation to incorporate a current and five-year outlook as an amendment to the proposed IRP rule with regard to smart grid.

Further, the Public Staff believes that identifying the potential demand and energy savings resulting from a technology is consistent with its understanding of the intent of the IRP process. The Public Staff concurred with Duke and DNCP's initial recommendation to include a description of "gross" demand and energy impacts as part of the smart grid submission. However, the Public Staff reiterated its initial recommendation that demand and energy impacts should also be classified on a system, retail jurisdictional, and retail customer class basis, as opposed to being classified as Duke and DNCP suggested in their initial comments. Further, the Public Staff reiterated its recommendation to exclude costs associated with smart grid technologies and also disagreed with NCSEA's recommendation to define smart grid technologies as either DSM or EE resources.[1] Finally, the Public Staff concurred with NCSEA's recommendation to include the term "two-way communication" in the definition of smart grid

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[1] As discussed in its initial comments and excluded in its revised amendment, the Public Staff opposed the inclusion of smart grid cost and cost recovery information, stating that the IRP is not a cost recovery proceeding and that the inclusion of such information may impact ratemaking and cost recovery proceedings. Additionally, the Public Staff excluded any proposed requirement that smart grid technologies be classified as either DSM or EE. In its exclusion of DSM or EE classification, the Public Staff argued that, similar to cost recovery, determination and classification of such remains within the discretion of the Commission in DSM and EE program approval proceedings.

technologies, but recommended that the definition of smart grid technologies not be limited only to “two-way communication” as it may not be a component of every smart grid technology.

In addition, the Public Staff recommended that the Commission be kept apprised of other aspects of a utility’s plans regarding the implementation of smart grid technologies. Therefore, the Public Staff recommended that the Commission adopt an additional smart grid rule, Rule R8-60.1, outside the context of the current IRP process to address the filing of smart grid plans with the Commission on a periodic basis, so that the Commission remains apprised of smart grid development. The Public Staff believes that the January 26, 2010, smart grid presentations by the IOUs demonstrated that smart grid technologies have a tremendous potential effect on the energy delivery of an electric utility in North Carolina. Further, the Public Staff noted that, based on its understanding of the IOUs’ presentations, the deployment of smart grid technologies will require substantial investments by both the electric utilities and the ratepayers. Based on this understanding, the Public Staff recommended transparency, from both a service and cost perspective, where possible.

In its proposed Rule R8-60.1, the Public Staff recommended that the utilities make filings every two years, with annual updates, providing information regarding an electric utility’s goals and objectives for smart grid, the interoperability of smart grid technologies proposed, the respective impacts of smart grid technologies to reliability and grid security, and a demonstrated correlation of how proposed smart grid technologies will improve an electric utility’s goals and objectives for utility operations. Further, the Public Staff recommended that the description of smart grid technologies be broadened beyond the scope of the IRP context to address the potential concerns regarding the double-counting of impacts from DSM and EE programs. Lastly, the Public Staff recommended that summary information be required to be provided for smart grid pilot and non-pilot projects, including a description of whether, and to what extent, a project is government funded. The Public Staff recommended excluding NCSEA’s recommendation for the inclusion on non-utility investments in the electric grid attributable to smart grid technology investments, citing its inability to determine whether NCSEA’s recommendation referred to government grants or other investments.

Finally, the Public Staff recommended excluding NCESA’s recommendation to include a description of transmission and distribution projects deferred due to smart grid projects, as well as a description of the societal benefits attributable to smart grid technologies. Rather, the Public Staff believes that utilities may provide such information with respect to the deferral of projects in their IRPs and cost-benefit analyses. Similarly, the Public Staff stated that specific identification regarding projects may be problematic within the context of a utility’s supply-side expansion process, in which the scale and timing of projects are simultaneously impacted by many variables. Finally, the Public Staff concurred with NCSEA that there may be significant societal benefits from smart grid. However, the Public Staff believes that benefits should be clearly quantifiable in order to be included in the cost-benefit analysis portion of its proposed rule. To the extent that the societal benefits proposed by NCSEA are not clearly quantifiable, the Public Staff does not believe its proposed rule should require a description of such.

DISCUSSION AND CONCLUSIONS

Based upon the foregoing and the entire record in this proceeding, the Commission agrees with and finds merit in many of the recommendations proposed in the comments by the parties. First, the Commission agrees with the Public Staff that the amendment to Rule R8-60 should apply to all entities subject to the IRP Rule, as opposed to only the IOUs. Further, the Commission agrees that the proposed amendment of Rule R8-60 should be revised to emphasize the potential impacts of smart grid technology on resource planning and load forecasting, as opposed to a smart grid technology plan irrespective of its impacts to the IRP. The Commission is persuaded that an emphasis on the impacts of smart grid technologies on resource planning and load forecasting are more aligned with the functional intent of the IRP process. The Commission also agrees with the Public Staff that the description of the proposed smart grid technologies should be based on the smart grid technology producing the impacts on resource planning and load forecasting. Consistent with the revised focus and description of smart grid technology impact plans, the Commission concludes that the smart grid impact plans should reflect a present and five-year outlook. The Commission is persuaded that a five-year outlook provides a reasonable projection with respect to the fifteen-year forecast of native load and other system capacity or firm energy obligations as currently defined in the IRP process. Further, the Commission acknowledges PEC’s use of the Smart Grid Maturity Model (SGMM) in its development of a smart grid roadmap and/or deployment plan. The Commission concludes that PEC’s use of the SGMM and/or use of a comparable industry accepted resources enhances the Commission’s initial proposal with regard to managing a smart grid technology plan.[1]

Further, the Commission agrees with the recommendation that utilities should be required to identify the potential demand and energy benefits derived from the smart grid technologies deployed. The Public Staff’s revised recommendation that demand and energy impacts be classified on a system, retail jurisdictional, and retail customer class basis enhances the Commission’s initial proposal on this issue. The Commission is persuaded that measurement and verification plans with respect to the impact classifications should be provided as part of the smart grid impact plan. The Commission is further persuaded that the inclusion of cost recovery plans and anticipated tariff details are inconsistent with the IRP process.

The Commission agrees with NCSEA that the term “two-way communication” should be included in the definition of smart grid technology. However, the Commission does not seek to limit the definition of smart grid only to “two-way communication”. The Commission acknowledges that two-way communication is an essential characteristic of smart grid technologies. The “smart” in smart grid speaks to the ability to process information, thus establishing an intrinsic need to receive information for processing. Additionally, in order for the information received and processed to have value beyond the system performing the processing, the system must have the ability to also communicate results, thus establishing a two-way communication as an element of an intelligent or smart technology. Consistent with this understanding of smart grid, the Commission agrees that the term two-way communication

[1] The SGMM is a management tool hosted by Carnegie Mellon University’s Software Engineering Institute that “helps utilities plan smart grid implementation, prioritize options, and measure progress.” The SGMM is not to be utilized as a prescriptive smart grid tool, but rather as a resource to aid utilities in their transformation and deployment of smart grid technologies.

should be added to the definition of smart grid, but does not seek to restrict smart grid only to two-way communication.

Regarding NCSEA's recommendation that utilities classify a smart grid technology as either a DSM or EE resources in their IRP filings, the Commission agrees with the Public Staff that designation of such classifications are not necessary within the IRP process. Further, the Commission notes that DSM and EE program determinations are specifically addressed under Rule R8-68, as opposed to Rule R8-60.

Finally, the Commission agrees with the Public Staff's recommendation that the Commission adopt an additional smart grid rule, Rule R8-60.1, to provide periodic reporting on additional details regarding a utility's smart grid technology plan. Further, the Commission concludes that Rule R8-60.1, as adopted by the Commission, reasonably addresses the comments made by the parties. The Commission agrees with the Public Staff that details regarding GHG emissions impacts, societal benefits, transmission and distribution deferrals, and non-utility investments related to smart grid should not be included in Rule R8-60.1. Specifically, GHG emissions and societal benefits are subjective in nature. To the extent relevant, reasonable and comparable information currently included in the IRP filing address and/or can be discerned with respect to GHG emissions and societal benefits. The Commission also agrees with the Public Staff that the utilities may provide some information with respect to the deferral of transmission and distribution projects in their IRPs and cost-benefit analyses, but the specific identification of such projects may be problematic within the context of a utility's supply-side expansion process, in which the scale and timing of projects are simultaneously impacted by many variables. Finally, the Commission concludes that requiring information on the status of pilot projects and current and/or existing projects, along with a description of its funding affiliation, reasonably address non-utility investments regarding smart grid.

Appendix A attached to this Order is a clean version of Rules R8-60 and R8-60.1, as provided herein. Appendix B attached to this Order is a black-lined version of the final rules comparing the final Rule R8-60 to the proposed rule attached to the Commission's December 28, 2009 Order and comparing the final Rule R8-60.1 to the proposed rule attached to the Public Staff's March 26, 2010 reply comments.

IT IS, THEREFORE, ORDERED that Rules R8-60 and R8-60.1, attached as Appendix A, shall be, and are hereby, adopted.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of April, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

k2041112.02

APPENDIX A
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Rule R8-60(i)(10) is revised as follows:

(i) Contents of Reports. Each utility shall include in each biennial report, revised as applicable in each annual report, the following:

. . .

(10) Smart Grid Impacts. – Each utility shall provide information regarding the impacts of its smart grid deployment plan on the overall IRP.

For purposes of this requirement, the term “smart” in smart grid shall be understood to mean, but is not limited to, a system having the ability to receive, process, and send information and/or data – essentially establishing a two-way communication protocol.

For purposes of this requirement, smart grid technologies that are implemented in a smart grid deployment plan may include those that: (1) utilize digital information and controls technology to improve the reliability, security and efficiency of an electric utility’s distribution or transmission system; (2) optimize grid operations dynamically; (3) improve the operational integration of distributed and/or intermittent generation sources, energy storage, demand response, demand-side resources and energy efficiency; (4) provide utility operators with data concerning the operations and status of the distribution and/or transmission system, as well as automating some operations; and/or (5) provide customers with usage information.

The information provided shall include:

(a) A description of the technology installed and for which installation is scheduled to begin in the next five years and the resulting and projected net impacts from installation of that technology, including, if applicable, the potential demand (MW) and energy (MWh) savings resulting from the described technology.

(b) A comparison to “gross” MW and MWh without installation of the described smart grid technology.

(c) A description of MW and MWh impacts on a system, North Carolina retail jurisdictional, and North Carolina retail customer class basis, including proposed plans for measurement and verification of customer impacts or actual measurement and verification of customer impacts.

Rule R8-60.1 is added as follows:

Rule R8-60.1. Smart Grid Technology Plans and Filings

(a) Purpose. – The purpose of this rule is to establish guidelines for the reporting of information regarding a utility's smart grid technology plan in addition to that required in Rule R8-60.

(b) Smart Grid Technology Plan. – By July 1, 2013, and every two years thereafter, each utility subject to Rule R8-60 shall file with the Commission its smart grid technology plan. Significant amendments or revisions to a smart grid technology plan shall be reported to the Commission in each year in which the biennial smart grid technology plan is not required to be filed.

(c) For purposes of this Rule, smart grid technologies are as set forth in Rule R8-60 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 control options.

The plan shall include:

(1) A description of the technology for which installation is scheduled to begin in the next five years, including the goal and objective of that technology, options for ensuring interoperability of the technology with different technologies and the legacy system, and the life of the technology.

(2) A smart grid maturity model "roadmap," if applicable, or roadmap from a comparable industry accepted resource suitable for the development of smart grid technology.

(3) Approximate timing and amount of capital expenditures.

(4) Cost-benefit analyses for installations that are planned to begin within the next five years, including an explanation of the methodology and inputs used to perform the cost-benefit analyses.

(5) A description of existing equipment, if any, to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

(6) Status of pilot projects and projects, including a description of whether and to what extent these projects are or will be funded by government grants.

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(7) A description, if applicable, of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

(8) A description, if applicable, 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.

(9) A description of how the proposed smart grid technology plan will improve reliability and security of the grid.

(d) Within 30 days after the filing of each utility's smart grid technology plan, the Public Staff or any other intervenor may file comments on any or all of the plans. Within 14 days after the filing of initial comments, the parties may file reply comments addressing any substantive or procedural issues raised by any other party. A hearing to address issues raised by the Public Staff or any other intervenors may be scheduled at the discretion of the Commission. The scope of such hearing shall be limited to such issues as identified by the Commission. Any approval of a smart grid technology plan shall not constitute an approval of the recovery of costs or of any specific technology or program associated with the plan.

APPENDIX B
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Rule R8-60(i)(10) is revised as follows:

(i) Contents of Reports. Each utility shall include in each biennial report, revised as applicable in each annual report, the following:

. . .

(10) Smart Grid ~~Technology Plan~~ Impacts. – Each ~~investor-owned electric~~ utility shall provide information regarding the impacts of its smart grid ~~technology~~ deployment plan on the overall IRP.

For purposes of this requirement, the term "smart" in smart grid shall be understood to mean, but is not limited to, a system having the ability to receive, process, and send information and/or data – essentially establishing a two-way communication protocol.

For purposes of this requirement, ~~S~~smart grid technologies that are implemented in a smart grid deployment plan may include those that (1) ~~use~~ utilize digital information and controls technology to improve the reliability, security and efficiency of the electric utility's distribution or transmission system; (2) optimize grid operations dynamically; (3)

improve the operational integration of distributed and/or intermittent generation sources, energy storage, demand response, demand-side resources and energy efficiency; (4) provide ~~real-time, automated, interactive technologies that optimize operation of consumer devices and appliances, including metering of customer usage; (5) provide~~ utility operators with data concerning the operations and status of the distribution and/or transmission system, as well as automating some operations; and/or (~~6~~5) provide customers with usage information ~~and control options~~.

The ~~plan~~ information provided shall include:

(~~A~~a) A description of the technology installed and for which installation is scheduled to begin in the next five years and the resulting and projected net impacts from installation of that technology, including, if applicable, the potential demand (MW) and energy (MWh) savings resulting from the described technology. ~~including the life of the technology, the impacts on the utility's delivery system, and, if applicable, the potential energy and peak demand savings resulting from the described technology~~.

(~~B~~b) A comparison to "gross" MW and MWh without installation of the described smart grid technology.

(~~C~~c) A description of ~~customer~~ MW and MWh impacts on a system, North Carolina retail jurisdictional, and North Carolina retail customer class basis, including ~~functions/services to be provided and~~ proposed plans for measurement and verification of customer impacts or actual measurement and verification of customer impacts.

~~(C) Approximate timing and amount of capital expenditures.~~

~~(D) Cost-benefit analyses for installations that are planned to begin within the next five years, including an explanation of the methodology and inputs used to perform the cost-benefit analyses.~~

~~(E) A description of existing equipment, if any, to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.~~

~~(F) Status of pilot projects and projects, including a description of whether and to what extent these projects are or will be funded by government grants.~~

~~(G) A description, if applicable, of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.~~

~~(H) A description, if applicable, 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.~~

Rule R8-60.1 is added as follows:

Commission Rule R8-60.1. Smart Grid technology plans and filings

(a) Purpose. – The purpose of this rule is to establish guidelines for the reporting of information regarding a utility's smart grid technology plan in addition to that required in Rule R8-60.

(~~a10~~b) Smart Grid Technology Plan. – By July 1, 201~~0~~3, and every two years thereafter, ~~E~~each~~ investor-owned electric~~ utility subject to Rule R8-60 shall ~~provide~~ file with the Commission its smart grid technology plan. Significant amendments or revisions to a smart grid technology plan shall be reported to the Commission in each year in which the biennial smart grid technology plan is not required to be filed.

(~~b~~c) For purposes of this Rule, ~~S~~smart grid technologies are as set forth in Rule R8-60 and shall also ~~shall~~ include those that ~~(1) use digital information and controls technology to improve reliability, security and efficiency of the electric distribution or transmission system; (2) optimize grid operations dynamically; (3) improve the operational integration of distributed and/or intermittent generation sources, energy storage, demand response, demand-side resources and energy efficiency; (4)~~ provide real-time, automated, interactive technologies that enable the optimiz~~e~~ation and/or operation of consumer devices and appliances, including metering of customer usage and~~; (5) provide utility operators with data concerning the operations and status of the distribution and/or transmission system, as well as automating some operations; and/or (6)~~ provide customers with ~~usage information and~~ control options.

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The plan shall include:

(1~~A~~) A description of the ~~T~~technology ~~to be~~ for which install~~ed.~~ation is scheduled to begin in the next five years, including the goal and objective of that technology, options for ensuring interoperability of the technology with different technologies and the legacy system, and the life of the technology.

(2) A smart grid maturity model "roadmap", if applicable, or roadmap from a comparable industry accepted resource suitable for the development of smart grid technology.

(~~B~~2) ~~A description of customer impacts on a system, North Carolina retail jurisdictional, and North Carolina retail customer class basis, including functions/services to be provided and proposed plans for measurement and verification of customer impacts or actual measurement and verification of customer impacts.~~

(~~C~~3~~.~~) Approximate timing and ~~size~~ amount of capital expenditures.

(~~D~~34) Cost-benefit analyses for installations that are planned to begin within the next five years, including an explanation of the methodology and inputs used to perform the cost-benefit analyses.

(~~E~~45) A d~~D~~escription of existing equipment, if any, to be rendered obsolete by the new technology, ~~and~~ its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

(~~G~~56) Status of pilot projects and projects, including a description of whether and to what extent these projects are or will be funded ~~at least partially~~ by government grants.

(~~G~~67) A description, if applicable, of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

(~~7~~8) A description, if applicable, 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.

(~~8~~9) A description of how the proposed smart grid technology plan will improve reliability and security of the grid.

(~~c~~d) Within 30 days after the filing of each utility's smart grid technology plan, the Public Staff or any other intervenor may file comments on any or all of the plans. Within 14 days after the filing of initial comments, the parties may file reply comments addressing any substantive or procedural issue raised by any other party. A hearing to

address issues raised by the Public Staff or any other intervenors may be scheduled at the discretion of the Commission. The scope of such hearing shall be limited to such issues as identified by the Commission. Any approval of a smart grid technology plan shall not constitute an approval of the recovery of costs or of any specific technology or program associated with the plan.

DOCKET NO. E-100, SUB 128
DOCKET NO. E-100, SUB 131

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 128	)	
	)	
In the Matter of	)	
Investigation of Integrated Resource	)	ORDER APPROVING 2010 REPS
Planning in North Carolina – 2010-2011	)	COMPLIANCE AND REQUIRING
	)	LEVELIZATION OF COSTS
DOCKET NO. E-100, SUB 131	)	
	)	
In the Matter of	)	
2011 REPS Compliance Plans and	)	
2010 REPS Compliance Reports	)	

BY THE COMMISSION: On February 9, 2012, the Commission issued an Order in the above-captioned dockets requiring the Town of Oak City (Oak City) and the Town of Winterville (Winterville) to verify their 2010 Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance reports on or before March 15, 2012, and requesting that the Public Staff review the 2010 REPS compliance reports as listed in the Order and submit comments to the Commission on or before April 5, 2012. Comments from other parties also were due on or before April 5, 2012.

On February 23, 2012, Winterville filed the required verification.

On April 3, 2012, the Public Staff requested an extension of time to file its comments. The Commission approved the extension on April 4, 2012. The Public Staff filed its comments on April 27, 2012. No other party filed comments in this matter.

The Public Staff stated that it had reviewed the 2010 REPS compliance reports that had been filed in the fall of 2011 by the following organizations: EnergyUnited Electric Membership Corporation (EnergyUnited), Fayetteville Public Works Commission (Fayetteville), the Town of Fountain (Fountain), GreenCo Solutions, Inc. (GreenCo), [1] Halifax Electric Membership

[1] GreenCo filed a consolidated 2010 REPS compliance report on behalf of Albemarle Electric Membership Corporation (EMC), Brunswick EMC, Cape Hatteras EMC, Carteret-Craven EMC, 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, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union EMC, and Wake EMC. GreenCo also reported 2010 REPS compliance for Broad River Electric Cooperative, and Mecklenburg Electric Cooperative, which are headquartered in South Carolina and Virginia, respectively.

Corporation (Halifax),[1] North Carolina Eastern Municipal Power Agency (NCEMPA),[2] North Carolina Municipal Power Agency 1 (NCMPA1),[3] the Town of Oak City (Oak City), Tennessee Valley Authority (TVA),[4] and the Town of Winterville (Winterville).

G.S. 62-133.8(d) requires all electric power suppliers in 2010 to meet 0.02 percent of their 2009 retail sales with solar energy. G.S. 62-133.8(c) provides that EMCs and municipal power suppliers may meet their REPS obligations by purchasing renewable energy certificates (RECs). G.S. 62-133.8(d) requires that no more than 25 percent of such RECs can be derived from out-of-state renewable energy facilities.

The Public Staff stated that all of the electric power suppliers listed above have met their 2010 REPS obligations; that none of them met their obligation with more than 25 percent out-of-state RECs; and recommended that the Commission approve the 2010 REPS compliance reports that were filed by EnergyUnited, Fayetteville, Fountain, GreenCo, Halifax, NCEMPA, NCMPA1, Oak City, TVA, and Winterville. The Public Staff noted that many electric power suppliers have earned energy efficiency certificates (EECs) but have not provided measurement and verification (M&V) information supporting their quantification. The Public Staff stated that it would accept the electric power suppliers' quantifications of EECs as temporary placeholders subject to reconsideration after they provide M&V data for review.

EnergyUnited

EnergyUnited's 2010 REPS compliance report stated that its 2009 retail sales were 2,230,849 MWh, making its 2010 REPS obligation 447 solar RECs. The records in the North Carolina Renewable Energy Tracking System (NC-RETS) show that EnergyUnited transferred 447 solar RECs into its 2010 compliance sub-account. Based on this information and the Public Staff's recommendation, the Commission finds that EnergyUnited met its 2010 REPS obligation.

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[1] Halifax's 2010 REPS compliance report stated that it was filing on behalf of itself and the Town of Enfield (Enfield).

[2] NCEMPA filed a consolidated 2010 REPS compliance report on behalf of Apex, Ayden, Belhaven, Benson, Clayton, Edenton, Elizabeth City, Farmville, Fremont, Greenville, Hamilton, Hertford, Hobgood, Hookerton, Kinston, LaGrange, Laurinburg, Louisburg, Lumberton, New Bern, Pikeville, Red Springs, Robersonville, Rocky Mount, Scotland Neck, Selma, Smithfield, Southport, Tarboro, Wake Forest, Washington, and Wilson. The retail sales, customer accounts, and REPS obligations of Pinetops, Macclesfield, and Walstonburg which are served on a wholesale basis by Wilson, were also included in NCEMPA's report.

[3] NCMPA1 filed a consolidated 2010 REPS compliance report on behalf of Albemarle, Bostic, Cherryville, Cornelius, Drexel, Gastonia, Granite Falls, High Point, Huntersville, Landis, Lexington, Lincolnton, Maiden, Monroe, Morganton, Newton, Pineville, Shelby, and Statesville.

[4] TVA filed a consolidated 2010 REPS compliance report on behalf of Tri-State EMC, Mountain EMC, Blue Ridge Mountain EMC, and the Murphy Electric Power Board.

Fayetteville

Fayetteville's 2009 REPS compliance report stated that its retail sales in 2009 were 2,067,063,579 kWh (2,067,064 MWh). Fayetteville's records in NC-RETS similarly state that its 2009 retail sales were 2,067,063 MWh; and that its 2010 REPS obligation is 414 solar RECs. However, Fayetteville actually placed 423 solar RECs into its 2010 compliance sub-account. Based on these records, Fayetteville "over complied" by nine RECs. However, Fayetteville's 2010 REPS compliance report stated that its 2009 retail sales were somewhat higher than what Fayetteville had reported earlier: 2,115,884 MWh, which would correspond to a 2010 REPS compliance obligation of 423 solar RECs, the same number of RECs that Fayetteville placed into its NC-RETS compliance sub-account.

On April 30, 2012, Fayetteville filed a revised 2009 REPS compliance report in Docket No. E-100, Sub 129, and stated that in that revised report it reduced its 2009 retail sales and accounts by subtracting those associated with service to all of Fayetteville's accounts (presumably sales and accounts related to its electric, water, sewer, and solid waste operations). Fayetteville stated that, with that adjustment, its 2009 retail sales were 2,007,310,452 kWh (2,007,310 MWh). Assuming such an adjustment is appropriate, Fayetteville's 2010 REPS obligation would be 401 solar RECs. However, Fayetteville did not request that its 2010 REPS obligation be revised.

Fayetteville also filed a revised 2010 REPS compliance report on April 30, 2012, in Docket No. E-100, Sub 131. Again, Fayetteville asserted that its 2010 retail sales figures and number of customer accounts should be adjusted to exclude all sales and accounts for service to Fayetteville accounts. Again, Fayetteville did not propose to revise the number of RECs needed for its 2010 REPS compliance.

In its April 27, 2012 comments, the Public Staff stated that it opposed Fayetteville's then-anticipated request to adjust its 2009 retail sales. The Public Staff agreed that Fayetteville should exclude electricity use and accounts related to its own electric operations, but stated that other Fayetteville accounts, such as those related to Fayetteville's sewer and water operations, should be included in the retail sales and accounts used to calculate Fayetteville's REPS obligations and spending caps. The Public Staff did not provide a 2009 retail sales figure (or 2010 REPS obligation) that corresponded with its proposed approach.

The Commission finds that the number of RECs actually placed in Fayetteville's 2010 compliance sub-account in NC-RETS, 423 solar RECs, corresponds with the highest 2009 retail sales figure of the three that have been posited for Fayetteville. In addition, Fayetteville's proposed revised 2010 REPS compliance report filed on April 30, 2012, does not go so far as to propose a revised number of RECs for Fayetteville's 2010 REPS compliance. Thus, the Commission concludes that Fayetteville has in fact complied with its 2010 REPS obligation.

The Commission will address Fayetteville's April 30, 2012 proposed revisions to its 2009 and 2010 REPS compliance reports in a separate order.

Fountain

Fountain filed its 2010 REPS compliance report on October 25, 2011. Fountain did not provide a 2009 retail sales figure, but the Public Staff stated that Fountain's 2010 retail sales were 3,733 MWh. Fountain's report stated that its 2010 REPS compliance obligation was one solar REC, which is consistent with the sales figure provided by the Public Staff. Fountain did not meet its 2010 REPS requirement during 2010. The report stated that Fountain bought two solar RECs in October of 2011 and proposed that they be used to meet its 2010 and 2011 REPS requirements. The records in NC-RETS show that Fountain transferred two solar RECs into a compliance sub-account labeled "2010-2011 Compliance." Based on Fountain's compliance report and its records in NC-RETS, the Commission finds that Fountain should have acquired at least one solar REC in 2010 but that it did not do so until 2011. Similarly, Fountain was late in filing its 2010 REPS compliance report. However, because Fountain has taken actions to come into compliance, and based on the Public Staff's recommendation, the Commission nonetheless finds that Fountain met its 2010 REPS obligation.

GreenCo

GreenCo's 2010 REPS compliance report stated that the 2009 retail sales of its 22 participating electric power suppliers were 12,038,916 MWh, making their aggregated 2010 REPS obligation 2,408 solar RECs. The records in NC-RETS show that GreenCo transferred 2,408 solar RECs into a 2010 compliance sub-account established on behalf of its 22 participating electric power suppliers. Based on this information and the Public Staff's recommendation, the Commission finds that GreenCo's 22 participating electric power suppliers met their 2010 REPS obligations. In addition, GreenCo established two REPS compliance sub-accounts separately on behalf of Mecklenburg and Broad River, which had 2009 retail sales of 1,513 MWh and 4,767 MWh respectively. Based on these 2009 retails sales, each of these electric power suppliers had a 2009 REPS obligation of one solar REC. The records in NC-RETS show that GreenCo transferred one solar REC each into Broad River and Mecklenburg's compliance sub-accounts. Based on this information, the Commission finds that Broad River and Mecklenburg met their 2010 REPS obligations.

Halifax

Halifax's 2010 REPS compliance report stated that its 2009 retail sales, including sales for Enfield, were 193,698,564 kWh (193,699 MWh), making their combined 2010 REPS obligation 39 solar RECs. The records in NC-RETS show that Halifax transferred 39 solar RECs into its 2010 compliance sub-account. Based on this information and the Public Staff's recommendation, the Commission finds that Halifax and Enfield met their 2010 REPS obligations. However, the Commission notes that Halifax did not list Enfield as an aggregated utility in its NC-RETS compliance sub-account. The Commission will require Halifax to revise its NC-RETS records to clarify that both Halifax and Enfield's REPS compliance is reflected in Halifax's compliance sub-account.

NCEMPA

NCEMPA's 2010 REPS compliance report stated that the 2009 retail sales of its 35 participating electric power suppliers was an aggregate of 6,876,778 MWh, making their combined 2010 REPS compliance obligation 1,376 solar RECs. The records in NC-RETS show that NCEMPA established a 2010 compliance sub-account on behalf of its 35 participating electric power suppliers, and transferred 1,376 solar RECs into that sub-account. Based on this information and the Public Staff's recommendation, the Commission finds that NCEMPA's 35 participating electric power suppliers met their 2010 REPS obligations.

NCMPA1

NCMPA1's 2010 REPS compliance report stated that the 2009 retail sales of its 19 participating electric power suppliers was an aggregate of 4,684,784 MWh, making their combined 2010 REPS obligation 937 solar RECs. The records in NC-RETS show that NCMPA1 established a 2010 compliance sub-account on behalf of its 19 participating electric power suppliers, and transferred 937 solar RECs into that sub-account. Based on this information and the Public Staff's recommendation, the Commission finds that NCMPA1's 19 participating electric power suppliers met their 2010 REPS obligations.

Oak City

Oak City's 2009 REPS compliance report stated that its 2009 retail sales were 3,280,651 kWh (3,281 MWh), making its 2010 REPS obligation one solar REC. The records in NC-RETS show slightly lower 2009 retail sales for Oak City of 3,010 MWh. The Commission finds that the difference is not material; either way, Oak City's 2010 REPS obligation was one solar REC. Oak City's 2010 REPS compliance report stated that it purchased one solar REC in 2010. The records in NC-RETS show that Oak City transferred one solar REC into its 2010 compliance sub-account. Based on this information and the Public Staff's recommendation, the Commission finds that Oak City met its 2010 REPS obligation, conditioned upon Oak City filing the verification for its 2010 REPS compliance report that was required in the Commission's February 9, 2012 Order. Oak City should ensure consistent REPS reporting in the future.

TVA

TVA's 2010 REPS compliance report stated that the 2009 retail sales for its four participating electric power suppliers were a combined 579,898 MWh, making their aggregate 2010 REPS compliance obligation 116 solar RECs. The records in NC-RETS show that TVA established a 2010 compliance sub-account on behalf of its four participating electric power suppliers and transferred 116 solar RECs into that account. Based on this information and the

Public Staff's recommendation, the Commission finds that TVA's four participating electric power suppliers met their 2010 REPS obligations.

Winterville

Winterville's 2009 REPS compliance report stated that its 2009 retail sales were 45,260,450 kWh (45,260 MWh), making its 2010 REPS obligation 10 solar RECs. The records in NC-RETS show that Winterville established a 2010 compliance sub-account and transferred 10 solar RECs into that account. Based on this information and the Public Staff's recommendation, the Commission finds and concludes that Winterville met its 2010 REPS obligation.

The Public Staff noted that Winterville reported incremental REPS spending in 2010 of $44,137, which exceeded its cost cap of $35,730. The Public Staff stated that some of Winterville's incremental REPS costs, such as consultant's fees and the startup costs of energy efficiency (EE) programs, should be levelized over a period of years. The Public Staff also stated that Winterville's EE programs could provide EECs into the future. Further, the Public Staff stated that Winterville took credit for 21 EECs attributed to its home energy audit program, but that Winterville had not actually completed any audits under the program. The Public Staff recommended that the Commission not accept these EECs until the audits are completed. Winterville reported 71 additional EECs that the Public Staff recommended should be treated as placeholders pending M&V.

The Commission agrees with the Public Staff that Winterville's EE programs should provide benefits into the future, and that levelizing the start-up costs of those programs would allow Winterville to comply with the REPS cost caps. The Commission's April 24, 2012 Order Allowing Levelization of REPS costs in Docket No. E-100, Sub 129 stated:

> [O]n a case-by-case basis, the Commission will require municipal utilities and EMCs to levelize such [REPS] costs, if necessary, to prevent the electric power supplier from hitting the cost cap in any one year due to spending that will produce benefits over multiple future years.

Therefore, the Commission finds that it is appropriate to require Winterville to use the M&V standards established in Docket No. E-100, Sub 113, as discussed below, to develop M&V documentation for its EE programs and to subsequently work with the Public Staff to develop a levelization schedule for its EE program start-up costs, which it shall file with its 2011 REPS compliance plan and report.

As discussed earlier, the Public Staff raised concerns with the M&V documentation for EECs reported by several electric power suppliers. The Commission will address that issue separately and on a generic basis in Docket No. E-100, Sub 113. That order will require all EMCs and municipal power suppliers to meet minimum standards for M&V starting with the REPS filings that are due in 2012.

IT IS, THERFORE, ORDERED as follows:

1. That the RECs in the NC-RETS 2010 compliance sub-accounts for EnergyUnited, Fayetteville, GreenCo, NCEMPA, NCMPA1, TVA, and Winterville shall be retired;

2. That Oak City has met its 2010 REPS obligation conditioned on the filing of its verification of its 2010 REPS compliance report, at which time the RECs in its NC-RETS 2010 compliance sub-account shall be retired;

3. That Halifax shall revise its 2010 compliance sub-account in NC-RETS to list Enfield as an aggregated utility, at which time the RECs in that sub-account shall be retired; and

4. That Fountain's 2010-2011 compliance sub-account in NC-RETS shall be maintained in "pending" status until the Commission reviews Fountain's 2011 REPS compliance; and

5. That Winterville shall develop M&V documentation for its EE programs and subsequently work with the Public Staff to develop a levelization schedule for its EE program start-up costs, which Winterville shall file with its 2011 REPS compliance plan and report.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of May, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

mr051412.03

DOCKET NO. E-100, SUB 129

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
2010 REPS Compliance Plans	)	ORDER APPROVING 2009 REPS COMPLIANCE
and 2009 REPS Compliance	)	REPORTS WITH CONDITIONS AND APPROVING
Reports	)	WAIVERS

BY THE COMMISSION: Commission Rule R8-67(c)(3) requires each municipal electric supplier and electric membership corporation (EMC), or its utility compliance aggregator, to file a verified Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance report on or before September 1 of each year. Similarly, Rule R8-67(b)(2) requires each electric power supplier to file a REPS compliance plan by September 1 of each year. On June 22, 2011, the Commission issued an Order requiring the Public Works Commission of Fayetteville (Fayetteville), the Town of Oak City (Oak City), and the Town of Winterville (Winterville) to verify their 2009 REPS compliance reports on or before September 1, 2011. The Order required the Town of Fountain (Fountain) to file its 2008, 2009, and 2010 REPS compliance reports and its 2010 and 2011 REPS compliance plans as required by Commission Rule R8-67 on or before September 1, 2011. Finally, the Order requested that the Public Staff review the 2009 REPS compliance reports that had been filed by the Tennessee Valley Authority (TVA)[1], Winterville, Oak City, and Fayetteville.

On August 30, 2011, the Public Staff filed comments regarding the 2009 REPS compliance reports that had been filed in the fall of 2010 by Winterville, Oak City, Fayetteville, and TVA. No other party filed comments in this matter.

<u>Fayetteville's 2009 REPS Compliance Report</u>

The Public Staff stated that Fayetteville's 2009 REPS compliance report claimed specific amounts of energy efficiency certificates (EECs), but that Fayetteville did not provide measurement and verification (M&V) information supporting its quantification of the energy savings. Page 7 of Fayetteville's report indicates that it is claiming 103 EECs from energy savings that occurred in 2008 and 2009 due to three efforts: the distribution of compact fluorescent light bulbs, the 2009 Consert $martWorks program, and the 2009 Consert load management program. In addition, Fayetteville stated that in the future it intends to count energy savings achieved via efficient technologies that were built into its new customer service center.

[1] TVA filed its report for the North Carolina distributors of its electric power, which are Blue Ridge Mountain EMC, the Town of Murphy, Tri-State EMC, and Mountain Electric Cooperative.

The Commission notes that Section 5.10 of the Operating Procedures for the North Carolina Renewable Energy Tracking System (NC-RETS), which were approved by the Commission on January 31, 2011, in Docket No. E-100, Sub 113, states as follows:

> An Electric Power Supplier that is eligible to demonstrate Portfolio [REPS] Compliance via Energy Efficiency Certificates … shall create a Project in NC-RETS for that purpose. The Electric Power Supplier … shall use the Self-Reporting Interface [in NC-RETS] to create EECs. The Electric Power Supplier … <u>shall retain for audit work papers demonstrating how it calculated the amount of EECs to be created</u>. Such work papers shall detail for each customer program the estimated volume of customer participation and related energy savings, adjustments for actual operating results (participation and savings rates) and the findings of measurement and verification analyses. [Emphasis added.]

While these requirements were not in place prior to the filing of Fayetteville's 2009 REPS compliance report, the Commission nonetheless believes it is reasonable to expect Fayetteville to develop the work papers required by the NC-RETS operating procedures and make them available to the Public Staff so that the Public Staff may verify that the EECs reported in Fayetteville's 2009 REPS compliance report and any corresponding EECs that Fayetteville might have created in NC-RETS are appropriate and consistent. It is incumbent upon all electric power suppliers to maintain records detailing the number of measure installations accomplished and their assumptions regarding savings and measure life.

As regards Fayetteville's intentions to count energy savings achieved via EE technologies that it incorporated into its new customer service center, the Commission will require additional information before it approves such EECs for REPS compliance. Fayetteville should explain how this effort meets the statutory definition of an EE measure that is eligible to be counted toward REPS compliance.

The Public Staff provided confidential information regarding Fayetteville's REPS spending and how its REPS incremental compliance costs compared to its cost cap. The Commission notes that it appears that Fayetteville is counting the purchase price of power from the Southeastern Power Administration (SEPA) as being a cost of REPS compliance. (See pages 8 and 9 of Fayetteville's compliance report.) This is inappropriate, as the RECs associated with SEPA allocations have no REPS incremental cost. As the Commission found in its May 3, 2011 Order in Docket No. E-48, Sub 6, involving the North Carolina Eastern Municipal Power Agency (NCEMPA):

> [T]he costs incurred for SEPA power are unnecessary and irrelevant for determining NCEMPA's incremental costs or a comparison of NCEMPA's incremental costs with its per-account cost cap. NCEMPA's members did not enter into a long-term power purchase agreement for SEPA power to meet the requirements of Senate Bill 3, such as they might have done for a new solar photovoltaic or other renewable energy facility. Rather, they were simply allowed to count toward REPS compliance the SEPA power already being purchased pursuant to existing agreements. Thus, since the municipalities are paying no more for SEPA power now that they are able to count it toward REPS compliance

> than they did previously, there is no incremental cost associated with SEPA RECs.

Fayetteville's report states that it reserves the right to recognize costs as having been incurred for "cost cap" purposes in the year that the associated RECs are used to comply with actual REPS requirements. This, too, would be inappropriate as the Commission stated on page 10 of its January 31, 2011 Order Amending Rules R8-64 Through R8-69 and Approving Final Operating Procedures for NC-RETS in Docket No. E-100, Sub 113:

> [I]t is clear that the General Assembly intended that REPS compliance be based on a calendar year period. … In subsection (h), the term "incremental costs" is defined primarily as the additional costs incurred for REPS compliance, and should be considered to be the incremental costs incurred during a calendar year for REPS compliance.

The Public Staff noted that Fayetteville had incurred $213,198 for EE efforts at a LEED certified building and an additional $20,682 for other EE and DSM programs which appeared to be designed to reduce energy use for a number of years. In the Public Staff's view, the costs of programs such as these – programs in which funds are expended at the beginning of the project in order to achieve energy savings over an extended period – should be levelized for REPS compliance purposes over the period during which savings are realized. The Commission acknowledges that the Public Staff's approach has been used in the DSM/EE rider proceedings for electric public utilities. While electric public utilities may recover their DSM/EE program costs through an annual rider, they are not able to count those costs toward the REPS cost cap. Municipal utilities and electric membership corporations, on the other hand, are able to count incremental costs of new DSM and EE programs towards the cost cap. The Commission believes that tracking REPS compliance costs for municipal utilities and electric membership corporations might be more straight-forward and less costly if it maintains the policy established in Docket No. E-100, Sub 113. That is, that the term "incremental costs" would continue to be defined as the additional costs incurred for REPS compliance during a calendar year, even for DSM and EE costs that have benefits into the future. Even so, the Public Staff's proposal has merit. Therefore, the Commission invites Fayetteville and any other interested parties to submit comments on this issue. In addition, the Commission notes that it has previously concluded that the general REPS requirements, which municipal utilities and electric membership corporations may meet via DSM and EE, are of lower priority than the solar, poultry waste and swine waste set asides.[1] Therefore, it would be inappropriate for a municipal utility or electric membership corporation to plan to comply with REPS via a singular focus on DSM and EE programs.

Commission Rule R8-67(c)(1)(iv) requires electric power suppliers to include in their annual REPS compliance reports "the actual total and incremental costs incurred during the calendar year to comply" with REPS. G.S. 62-133.8(h) defines "incremental costs" as being REPS compliance costs that "are in excess of the electric power supplier's avoided costs …." Fayetteville stated that it was not able to calculate its incremental costs for 2008 and 2009 and requested that the Commission waive its compliance with this requirement. The Public Staff

[1] See page 5 of Order on Duke Energy Carolinas, LLC, Motion For Clarification in Docket No. E-100, Sub 113, issued May 7, 2009.

noted that Fayetteville did not claim to have reached its cost cap in either 2008 or 2009 and recommended that the Commission approve Fayetteville's waiver request. While the Commission concludes that it is reasonable to waive the requirement for Fayetteville to calculate its incremental costs in its 2008 and 2009 compliance reports, the Commission nonetheless will require such calculations in future reports, and notes that a cost-effective EE program might very well not have any incremental costs.

The Public Staff noted that Fayetteville reserved the right to include lost retail sales in its calculations of REPS costs. The Public Staff recommended that the Commission maintain the position taken in its May 3, 2011 Order in Docket No. E-48, Sub 6.[1] There the Commission found that it is inappropriate to include net lost revenues as a cost of REPS compliance. The Commission agrees with the Public Staff and concludes that Fayetteville should not be allowed to include lost retail sales revenues in its REPS costs.

The Public Staff noted also that Fayetteville had reserved the right to meet its REPS obligations by relying on the REPS compliance of its wholesale provider, Progress Energy Carolinas, Inc. (Progress). Again, the Public Staff recommended that the Commission maintain the position taken in its May 3, 2011 Order in Docket No. E-48, Sub 6, in which the Commission found that an electric power supplier "may not count purchased power from a wholesale power supplier to satisfy its REPS requirements unless it shows that such power has associated with it a portfolio of supply and demand options that meets the requirements of G.S. 62-133.8." The Commission agrees with the Public Staff and concludes that Fayetteville should not be allowed to meet its REPS obligations by relying on Progress's REPS compliance.

Fayetteville noted that in its 2008 REPS compliance report it had failed to identify RECs that it had generated and wanted to carry forward for future compliance. It stated that this included approximately 16.5 EECs from its compact fluorescent light bulb distribution program, and 4,090 SEPA RECs. The Public Staff recommended that the Commission approve this request, subject to the results of Fayetteville's M&V process. The Commission concludes that Fayetteville's request should be approved, subject to the Public Staff's review of Fayetteville's EE work papers, as discussed above.

The Public Staff stated that, except as noted above, Fayetteville's 2009 REPS compliance report appears to comply with the requirements of Commission Rule R8-67(c) and should be approved by the Commission. On September 1, 2011, Fayetteville filed verification for its 2009 REPS compliance report as required by the Commission's June 22, 2011 Order. Upon review of Fayetteville's filings and the Public Staff's recommendation, the Commission concludes that Fayetteville's 2009 REPS compliance report should be approved, subject to the exceptions discussed above.

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[1] In the Matter of North Carolina Eastern Municipal Power Agency – 2008 REPS Compliance Report, Order on 2008 REPS Compliance Report.

Winterville's 2009 REPS Compliance Report

The Public Staff stated that Winterville's 2009 REPS compliance report claimed specific amounts of EECs, but that Winterville did not provide M&V information supporting its quantification of the energy savings. Winterville's report stated that it had earned 13 EECs in 2009 via an energy saver kit program, and 20 EECs via a compact fluorescent light bulb program.

As noted above, the NC-RETS Operating Procedures require electric power suppliers to retain for audit work papers demonstrating how they calculated EECs, such work papers to include the estimated volume of customer participation and related energy savings. While these requirements were not in place prior to the filing of Winterville's 2009 REPS compliance report, the Commission nonetheless believes it is reasonable to expect Winterville to develop the work papers required by the NC-RETS operating procedures and make them available to the Public Staff so that the Public Staff may verify that the EECs reported in Winterville's 2009 REPS compliance report and any corresponding EECs that Winterville might have created in NC-RETS, are appropriate and consistent. The Commission notes that, due to Winterville's small REPS budget, it would generally be inappropriate for Winterville to pursue extensive M&V of its EE activities. However, it is incumbent upon all electric power suppliers, however small, to maintain records detailing the number of measure installations accomplished each year and their assumptions regarding savings and measure life.

Winterville reported that its REPS incremental compliance costs for 2009 were $51,311, which exceeded its cost cap of $42,530. According to Winterville's compliance report, $25,855 of its costs was for services provided by its consultant, Cardinal Energy Service; $6,000 represented administrative and general costs for staff and management time; and $19,456 was for five EE programs, three of which had not yet earned any EECs. Winterville stated that Cardinal Energy Service worked closely with Winterville to establish REPS compliance policies and procedures, EE program design and the preparation of Winterville's REPS compliance plan and report that were filed in August 2009. Winterville stated that equipment purchased for its energy audit program, compact fluorescent light bulbs, and energy saver kits, will last several years. The Public Staff recommended that the costs of Winterville's EE programs be levelized for REPS compliance purposes when the programs are designed to bring about energy savings over an extended period of time, and stated that by levelizing its EE costs, Winterville might be able to avoid exceeding its cost cap. The Commission notes that it appears that Winterville included the entire cost of its new EE programs, rather than only the incremental costs of those programs, in its cost cap calculations. To the extent that these new programs allow Winterville to avoid the cost of energy purchases, those avoided costs should have been subtracted from Winterville's program costs.

The Commission will allow parties to comment on whether it is preferable to track the REPS compliance costs of municipal utilities and electric membership corporations on a calendar year basis, even for DSM/EE programs and REPS planning efforts that have benefits extending several years into the future.

The Public Staff recommended that the Commission approve Winterville's 2009 REPS compliance report. However, the verification for Winterville's 2009 REPS compliance report has not yet been filed. Therefore, based on its own review and the comments of the Public Staff, the Commission concludes that Winterville's 2009 REPS compliance report should be conditionally approved, but directs Winterville to (1) file the verification for its 2009 REPS compliance report by March 16, 2012; (2) ensure that future reports include its incremental, as well as its total, costs of REPS compliance; and (3) annually establish and adhere to a REPS budget that is within the cost cap established by Session Law 2007-397.

Oak City's 2009 REPS Compliance Report

The Public Staff stated that Oak City did not obtain any RECs in 2009. Oak City's 2009 REPS compliance report states that it spent "approximately $1,000 for outside services related to REPS compliance and reporting, as well as certain staff effort that was not specifically accounted for." The report also states that "Oak City recovered the cost of existing energy efficiency and renewable energy programs as a normal operating expense through the existing rates." From this statement, it appears that Oak City does have some REPS-related programs. However, Oak City also stated that it

> has not purchased or earned any NC RECs, and there were no NC RECs carried forward as of December 31, 2009. … Oak City had not purchased any RECs from any facility as of December 31, 2009. … Oak City does not have a demand-side management program.

The report states that Oak City's REPS incremental cost cap is approximately $3,600. The Public Staff recommended that the Commission approve Oak City's 2009 REPS compliance report. On September 2, 2011, Oak City filed verification for its 2009 REPS compliance report and its 2010 REPS compliance plan as required by the Commission's June 22, 2011 Order. Therefore, the Commission will approve the report but directs Oak City to earmark a majority of its future REPS spending toward renewable energy (especially solar, swine waste, and poultry waste sources) and energy saving programs.

TVA's 2009 REPS Compliance Report

TVA had filed its report for the North Carolina distributors of its electric power, which are Blue Ridge Mountain EMC, the Town of Murphy, Tri-State EMC, and Mountain Electric Cooperative. TVA calculated an annual incremental REPS cost cap of $545,145 for the four distributors, but stated that they had not yet incurred any incremental REPS costs, nor had they acquired any RECs. The Public Staff recommended that TVA's 2009 REPS compliance report be approved. Therefore, the Commission concludes it is appropriate to approve TVA's 2009 REPS compliance report.

Fountain's REPS Compliance Reports

Fountain did not file any REPS compliance plans or reports in 2008, 2009, or 2010. The Commission's June 22, 2011 Order required Fountain to make these filings, along with its 2011 REPS compliance plan and 2010 REPS compliance report, on or before September 1, 2011. On September 20, 2011, Fountain wrote a letter to the Commission stating that

> until recently the Town was under the mistaken assumption that these requirements would be fulfilled on the Town's behalf by the filings of Pitt-Greene Electric Membership Corporation, the sole electricity supplier to the Town. However, we have recently learned that this is not the case. Accordingly, the Town is currently undertaking efforts to complete the required reports and will provide them to the Commission no later than December 31, 2011.

Until late 2011, Fountain did not take any actions to comply with the Commission's rules implementing Senate Bill 3. While this is unfortunate, the Commission finds that it would be a waste of resources to require Fountain to develop and submit over-due reports that would restate what is already known. The Commission notes that Fountain has taken steps to come into compliance, however belatedly.[1] Therefore, the Commission will waive Fountain's REPS reporting requirements for 2008 and 2009.

IT IS, THEREFORE, ORDERED as follows:

1. That Fayetteville and Winterville shall, by March 16, 2012, develop work papers documenting the energy savings in their 2009 REPS compliance reports for review by the Public Staff, and the Public Staff is requested to review these work papers and include a summary of its findings in its comments regarding Fayetteville and Winterville's 2010 REPS compliance reports;

2. That Fayetteville, Winterville, and other parties may file comments by March 16, 2012, on the question of whether municipal utilities and electric membership corporations should be required to levelize the costs of EE and DSM programs and REPS planning efforts over the period for which benefits are anticipated;

3. That Winterville shall annually establish and adhere to a REPS budget that is within the cost cap established by Session Law 2007-397;

4. That Winterville shall file its verification of its 2009 REPS compliance report by March 16, 2012; and

5. That the Commission shall waive the requirement for Fountain to file a REPS compliance report for 2008 and 2009.

ISSUED BY ORDER OF THE COMMISSION.
This the _21st_ day of February, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Chairman Edward S. Finley, Jr., did not participate in this decision.

kj022112.04

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[1] On October 25, 2011, Fountain filed a verified REPS compliance report for 2010, and a REPS compliance plan for 2011. Fountain's September 20, 2011 letter and subsequent REPS plan and report were filed in Docket No. E-100, Sub 131, and are pending.

DOCKET NO. P-100, SUB 99

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Quality of Service Objectives for	)	ORDER GRANTING CENTURYLINK'S
Local Exchange Telephone Companies	)	PETITION FOR FORCE MAJEURE
	)	WAIVER OF RULE R9-8

BY THE COMMISSION: On February 17, 2012, pursuant to Commission Rule R9-8(c), Carolina Telephone and Telegraph Company LLC d/b/a CenturyLink (CenturyLink) filed a Petition for Force Majeure Waiver of Measure No. 11 (Out-of-Service Troubles Cleared Within 24 Hours) of Commission Rule R9-8 for the time period from August 26, 2011 through as late as October 10, 2011 in 104 exchanges as a result of Hurricane Irene. CenturyLink asserted that significant portions of its territory in eastern and portions of central North Carolina were ravaged by devastating winds and rainfall from Hurricane Irene, which made landfall on August 27, 2011.

On February 28, 2012, the Commission issued an Order requesting comments on CenturyLink's Petition.

On March 5, 2012, CenturyLink filed amended Exhibits A and C to its February 17, 2012 Petition. CenturyLink noted that, by its submission, it was providing supplemental information in revised Exhibit A and correcting certain September 2011 results in revised confidential Exhibit C to the Petition.

On March 16, 2012, the Public Staff filed a Motion for Extensions of Time for the filing of initial and reply comments by the parties. By Order dated March 16, 2012, the Commission granted the Public Staff's Motion.

Initial comments were filed by the Public Staff on March 29, 2012. On April 12, 2012, CenturyLink filed a letter in lieu of more formal reply comments. No other parties filed initial or reply comments.

PETITION

CenturyLink stated in its Petition that it was requesting a force majeure waiver of Measure No. 11 (Out-of-Service Troubles Cleared Within 24 Hours) of Commission Rule R9-8 for the time period from August 26, 2011 through as late as October 10, 2011 in 104 exchanges as a result of Hurricane Irene. CenturyLink summarized the end date of the requested waiver period as follows:

End Date	Number of Exchanges
September 12, 2011	14 exchanges
September 16, 2011	34 exchanges
September 17, 2011	13 exchanges
September 23, 2011	6 exchanges
September 27, 2011	17 exchanges
September 30, 2011	11 exchanges
October 3, 2011	4 exchanges
October 10, 2011	5 exchanges

CenturyLink asserted that significant portions of its territory in eastern and portions of central North Carolina were ravaged by devastating winds and rainfall from Hurricane Irene, which made landfall on August 27, 2011[1].

CenturyLink maintained that it followed its internal Emergency Restoration Plan procedures to prepare for Hurricane Irene. CenturyLink noted that each spring, CenturyLink operation districts update their individual Emergency Restoration Plans, which include details such as a listing of essential service providers such as police, fire, and EMS, generator capacity and locations, as well as vendors for equipment and fuel. CenturyLink specified that the first alert of a potential damaging storm that could impact CenturyLink's service area was sent to CenturyLink field personnel on Sunday, August 21, 2011, with daily updates tracking the development of the storm. CenturyLink stated that, beginning on Tuesday, August 23, 2011, internal emergency preparedness calls were held on a daily basis to insure proper preparation was taking place and that additional resources were appropriately staged.

CenturyLink further stated that on August 24, 2011, Governor Beverly Perdue declared a state of emergency for the counties east of Interstate 95. CenturyLink noted that as the predicted path of the storm became more certain, employees in the areas expected to be most impacted were directed to storm preparation work rather than normal service duties. However, CenturyLink asserted, the size, severity, and duration of Hurricane Irene caused service issues that were beyond what could have been remedied by any amount of preparation efforts.

CenturyLink stated that Hurricane Irene made landfall at Cape Lookout on the morning of August 27, 2011 with sustained winds of 85 miles per hour and wind gusts up to 115 miles per hour. CenturyLink noted that Hurricane Irene's path tracked northward through the Outer Banks, slicing through CenturyLink's territory in eastern and portions of central North Carolina and leaving a broad swath of destruction in its wake. CenturyLink provided website links to maps which detail Hurricane Irene's path. CenturyLink asserted that storm surge along the coast was between five and nine feet, while four to nine feet of flooding occurred in areas adjacent to the Pamlico Sound. CenturyLink maintained that in addition to the high winds and storm surge, 10 to 14 inches of precipitation was measured in the affected areas. CenturyLink stated that the 300 miles-wide storm moved slowly across eastern North Carolina for 24 hours, traveling only

[1] CenturyLink specified that it is requesting relief beginning a day prior to the storm making landfall as significant resources were redirected from normal duties to hurricane preparedness on August 26, 2011.

14 miles per hour in a north-northeasterly direction while hitting the area with devastating wind and rain.

CenturyLink stated that Hurricane Irene claimed seven lives, injured numerous others, and destroyed and damaged thousands of homes and businesses. CenturyLink noted that the County Manager in Pamlico County estimated that over 30 percent of the homes in that county were flooded. CenturyLink maintained that it had three Digital Loop Carriers in the New Bern area that required complete replacement due to flooding from Pamlico Sound, with three others that required replacement of key internal components such as shelves, control cards, batteries, and rectifiers. CenturyLink noted that during the storm, a transfer truck in Kinston ran through 12 poles damaging 400-, 500-, and 900-pair copper cables, as well as a major CenturyLink fiber route. CenturyLink asserted that all cables and fiber required complete replacement due to the damage. CenturyLink further noted that more than 270 roads and 21 bridges were closed due to flooding, damage, or other debris. CenturyLink stated that one of the iconic images of Hurricane Irene's damage was the complete washout of State Highway 12 north of Rodanthe, which left portions of Hatteras Island inaccessible. CenturyLink noted that other portions of State Highway 12 were damaged, further impairing access to the Outer Banks and hampering recovery efforts. CenturyLink maintained that its service territory encompasses this area as well as the rest of the areas of the State that were hit hardest by the hurricane.

CenturyLink noted that the New Bern region was particularly hard hit by the storm, and it took weeks to clear debris in that area. CenturyLink stated that the city's proximity to the Neuse and Trent rivers, combined with being close to the coastline, made it particularly vulnerable to the storm. CenturyLink maintained that in the 24 hours during which Hurricane Irene passed through the New Bern area, 12 to 17 inches of rain fell. CenturyLink asserted that three weeks after the storm, only about 60 percent of the debris in the area had been cleared. CenturyLink noted that trucks from as far away as Michigan, Louisiana, and even Alaska, collected and hauled debris for weeks, but a first pass at clearing was not expected to be complete until the end of October.

CenturyLink also noted that Roanoke Rapids was devastated by Hurricane Irene. CenturyLink asserted that the Roanoke Valley area around and including Roanoke Rapids suffered over 100,000 downed trees, cutting power to tens of thousands of customers. CenturyLink stated that 10 days after the storm, Roanoke Rapids city officials reported that only about one-half of the storm debris had been removed. CenturyLink noted that the local newspaper reported that four months after the storm, there was still visible signs of damage such as tarps and uprooted trees.

CenturyLink maintained that, moreover, Hurricane Irene wreaked havoc on critical infrastructure in central and eastern North Carolina and this prevented CenturyLink from restoring service within the timeframes set forth in Rule R9-8, despite CenturyLink's substantial efforts to do so.

CenturyLink asserted that nearly one million people were without power at the storm's peak. CenturyLink noted that restoration of power is a vital factor which greatly affects CenturyLink's ability to return service to its customers. CenturyLink stated that it worked closely with its counterparts at the power companies to coordinate efforts to restore customers' utility services as quickly and as efficiently as possible. CenturyLink maintained that, in many cases, it was forced to wait until power crews cleared their downed lines, trees were cleared from roadways, and waters receded in order to be able to restore service. And, CenturyLink stated, because of the widespread damage caused by Hurricane Irene, the volume of repair work to be done was staggering.

CenturyLink noted that in addition to Governor Perdue's declared state of emergency pre-landfall, President Obama with the Federal Emergency Management Agency designated 34 North Carolina counties as federal disaster areas and made them eligible for federal relief. CenturyLink stated that the exchanges for which it seeks a waiver are those within the federal and State emergency declaration areas, as well as very limited areas in close proximity thereto that were also adversely affected by Hurricane Irene.

CenturyLink stated that it secured employees from North Carolina and seven other states and also engaged contractors to restore service to CenturyLink customers after the storm. CenturyLink maintained that the dramatic increase of service reports received by CenturyLink's call centers shows the devastating impact Hurricane Irene had across CenturyLink's eastern North Carolina exchanges and the overwhelming workload CenturyLink faced to restore service. CenturyLink provided confidential numbers indicating the amount by which troubles reported and out-of-service increased for September 2011 as compared to the same period for the prior year for the exchanges listed in Exhibit A; however, CenturyLink is not seeking force majeure relief for the Initial Customer Trouble Reports measure, but only for the Out-of-Service Troubles Cleared Within 24 Hours measure.

CenturyLink asserted that to recover from Hurricane Irene, it devoted the following resources to repair and recovery in addition to its existing eastern North Carolina workforce:

- 28 two- and three-man line crews replaced poles, cleared trees, and replaced downed cable. All crews stayed for at least two weeks, and some as long as four weeks.

- 27 contractors assisted with splicing and installation and repair load. Most contractors stayed for four weeks.

- 64 company employees were brought from western North Carolina, Ohio, Virginia, Tennessee, Alabama, South Carolina, Georgia, and Arkansas. Most stayed for two weeks and some stayed as long as four weeks.

CenturyLink noted that it incurred significant expenses to restore service including overtime labor costs, costs to replace cable, drops, electronic equipment and batteries, as well as costs to fuel generators, compensate employees and contractors, and feed and house out-of-area CenturyLink employees.

CenturyLink stated that in light of all the aforementioned effects of Hurricane Irene, it is seeking a waiver of the Out-of-Service Troubles Cleared Within 24 Hours measure for the period from August 26, 2011 up to as long as October 10, 2011 (until the exchange returned to average load) in the exchanges listed on Exhibit A of its Petition for the periods indicated there. CenturyLink argued that Hurricane Irene was sufficiently serious and unusual in nature to constitute a force majeure event. CenturyLink asserted that to the extent reasonably foreseeable and possible, CenturyLink prudently planned and prepared in advance for the event in accordance with the forecast. CenturyLink maintained that despite its substantial efforts before, during, and after the storm, it was unavoidable that CenturyLink's Out-of-Service Troubles Cleared Within 24 Hours measure declined as a result of Hurricane Irene's considerable impact on eastern and portions of central North Carolina. CenturyLink asserted that the extent and nature of the adjustments it requests to its service objectives are appropriate under the circumstances. CenturyLink maintained that the waiver it is seeking is narrowly tailored both with respect to the Rule R9-8 objectives for which CenturyLink seeks relief and with respect to the duration of the requested waiver. CenturyLink stated that while other service objectives declined due to the impact of the storm, the Out-of-Service Troubles Cleared Within 24 Hours measure was the service objective most significantly impacted and is the only one for which CenturyLink is seeking force majeure relief.

INITIAL COMMENTS

The Public Staff stated that it has reviewed CenturyLink's Petition and believes that CenturyLink's request meets the criteria set forth in Commission Rule R9-8(c). The Public Staff, therefore, recommended that the Commission grant the force majeure waiver sought by CenturyLink.

REPLY COMMENTS

CenturyLink filed a letter in lieu of more formal reply comments. CenturyLink stated that it requested that the Commission grant CenturyLink's Petition for the reasons set forth in the Petition.

DISCUSSION

Commission Rule R9-8(c) states as follows:

> Force Majeure. A company may seek a waiver of part or all of Rule R9-8 due to force majeure. To request a waiver, a company should file adjusted data and unadjusted data along with its waiver request. In order to secure Commission approval, the waiver request should clearly demonstrate that (1) the force majeure event was sufficiently serious and unusual to warrant adjustment of the monthly service quality statistics, including a detailed description of the adverse consequences of the event on the ratepayers' service and the company's facilities; (2) to the extent reasonably foreseeable, the company prudently planned and prepared in advance for such emergencies; (3) despite these plans and preparations, and the best efforts of the company personnel before, during, and after the event, failures to satisfy the service objectives could not reasonably have been avoided; **and** (4) the extent and nature of the adjustments requested are appropriate for the circumstances. The Commission shall grant waiver requests if the Commission finds that all four criteria have been met.

After a thorough review of CenturyLink's Petition, CenturyLink's amended Exhibits A and C, and the comments filed in this docket, the Commission finds that CenturyLink's force majeure waiver request meets all four of the criteria outlined in Rule R9-8(c). Therefore, the Commission finds it appropriate to grant CenturyLink's force majeure waiver request.

WHEREUPON, the Commission finds it appropriate to grant CenturyLink's Petition for a Force Majeure Waiver of Measure No. 11 (Out-of-Service Troubles Cleared Within 24 Hours) of Commission Rule R9-8 for the time period from August 26, 2011 through as late as October 10, 2011 in 104 exchanges as a result of Hurricane Irene.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the _18th_ day of April, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner William T. Culpepper, III did not participate in this decision.

bp041812.01

DOCKET NO. P-100, SUB 110

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Telecommunications Relay Service	)	ORDER APPROVING
(TRS), Relay North Carolina	)	SELECTION OF CONTRACTOR

BY THE COMMISSION: On November 7, 2011, the Department of Health and Human Services (DHHS) issued a Request for Proposals (RFP) to select a vendor to provide telecommunications relay service to North Carolina citizens. The new contract will be effective from July 1, 2012 to June 30, 2016. Pursuant to G.S. 62-157, DHHS is charged with administering the statewide telecommunications relay service program, including its establishment, operation, and promotion. Pursuant to G.S. 62-157(e) and as part of its administration of the program, DHHS is authorized to contract out provision of this service for four-year periods to one or more service providers, using the State bidding process. The present contractor is Sprint Communications Company, LP (Sprint). The present contract expires on June 30, 2012.

The Public Staff presented the results of the DHHS' process of selecting a contractor for the 2012-2016 time period at the Commission's Regular Staff Conference on June 11, 2012. The Public Staff stated that two companies submitted proposals in response to the RFP: Sprint and Hamilton Telephone Company d/b/a Hamilton Telecommunications (Hamilton). An evaluation committee reviewed the two proposals. The evaluation committee consisted of Susanna Bourgeois, Raleigh Regional Center Manager for the Division of Services for the Deaf and Hard of Hearing (DSDHH); Kevin Earp, Statewide Coordinator for Deafness & Communicative Disorders Division of Vocational Rehabilitation; Tammy Koger, Director, North Carolina Assistive Technology Program; and Pat Stivland, Communications Access Manager/Deaf & Deaf Blind Services Manager, DSDHH.

In its review, the evaluation committee considered the following: technical merit, qualifications, references, customer service, outreach, advertising program, and costs. The evaluation committee then weighed and scored each bidding vendor's performance with regard to these considerations

When evaluated pursuant to the considerations listed above, Sprint achieved the highest score and as a result, the evaluation committee recommended Sprint as the new contractor to the DHHS Office of Procurement and Contract Services. This recommendation and evaluation summary, the vendor's proposals in response to the RFP, and the individual scores, were reviewed by the DHHS Office of Procurement and Contract Services and a contract specialist at the Information Technology Services (ITS) Statewide Procurement Office. ITS approved the award of the contract to Sprint on May 22, 2012.

Per minute costs of relay calls will decrease as well as the monthly recurring charge, while the cost for a CapTel call will increase for the upcoming contract period. The cost per minute of a relay call will decrease by $0.04 from $.89 (2008-2012) to $.85 (2012-2016), and the cost per minute of a CapTel call will increase $0.15, from $1.45 (2008-2012) to $1.60 (2012-2016). The annual sum of the monthly recurring charge will decrease by $48,000, from $705,336 per year (2008-2012) to $657,336 per year (2012-2016). This monthly recurring rate will help fund Sprint's TRS outreach into North Carolina's deaf and hard of hearing community. The DHHS Office of Procurement and Contract Services estimated the total cost for the four-year period to be $22,277,344.

G.S. 62-157 provides that the Commission has the same power to regulate TRS as it has to regulate any other public utility subject to the provisions of Chapter 62. DHHS has in the past sought the approval of the Commission prior to the selection of the new contractor. The Public Staff has consulted with representatives of DHHS regarding its selection of Sprint as the contractor. Based on these consultations and a review of the RFP documents, the Public Staff recommended that the Commission approve the selection of Sprint as the contractor for relay services in the four-year period beginning July 1, 2012.

Based on the foregoing and the recommendation of the Public Staff, the Commission concludes that DHHS's selection of Sprint as the vendor to provide relay services in North Carolina for the four-year period beginning July 1, 2012 and ending June 30, 2016, should be approved.

IT IS, THEREFORE, ORDERED that DHHS's selection of Sprint as the contractor to provide TRS in North Carolina for the four-year period beginning July 1, 2012 is approved.

ISSUED BY ORDER OF THE COMMISSION.
This the _11th_ day of June, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioner William T. Culpepper, III, did not participate.

Bh061112.03

DOCKET NO. P-100, SUB 133f

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Amendment to Commission Rule R9-6 to Implement	)	ORDER AMENDING
Changes Required by the Lifeline and Link Up	)	COMMISSION RULE R9-6
Reform and Modernization Order	)	

BY THE COMMISSION: Lifeline and Link Up are federal low income subsidy programs which are administered by the State of North Carolina. As such, North Carolina policies and practices implementing Lifeline and Linkup subsidy programs must conform to and be consistent with federally mandated requirements.

On January 31, 2012, the FCC issued the Lifeline and Link Up Reform and Modernization Order (the Lifeline Reform Order) which adopted major changes to the Lifeline and Link Up programs. Two changes in particular, i.e., the change in the federal Lifeline amount from $10.00 or less to $9.25 or less and Link Up subsidy amount from $30.00 to zero would result in price increases for North Carolina Lifeline consumers.[1]

The changes announced in the Lifeline Reform Order were originally scheduled to become effective on April 2, 2012. Prior to the effective date, however, members of the telecommunications industry petitioned the FCC to delay the effective date of the regulations.[2] In a letter informing the Commission of this filing and requesting Commission support for the industry petition, the North Carolina Lifeline/Link Up Task Force (Task Force) noted that it would be difficult: (1) to implement the interim flat rate reimbursement amount of $9.25 in place of the current tiered reimbursement structure; (2) to eliminate the Link-up discount on non-tribal lands; and, (3) to implement changes to the Link-Up discount on Tribal lands by the FCC's April 2, 2012 deadline. See March 16, 2012 letter to the Commission filed in Docket No. P-100, Sub 133f.

On March 29, 2012, the FCC issued a Public Notice which effectively delayed the implementation date for the regulations implementing the changes to the Lifeline program. Thus, no action need be taken at this time to implement changes to the Lifeline program. The Public Notice was silent, however, as to whether the effective date of the newly enacted Link Up regulations would be delayed. Thus, the effective date of the newly enacted Link Up regulations remained April 2, 2012.

The policies governing the administration of the Link Up program in North Carolina are set forth in Commission Rule R9-6. Commission Rule R9-6 currently does not limit the Link Up subsidy to residents of Tribal lands subscribing to service from an eligible telecommunications

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[1] The Link Up subsidy would be reduced to zero for all consumers except for those subscribers on Tribal lands being served by eligible telecommunications carriers (ETCs) receiving high-cost support. 47 CFR 54.413.

[2] Petition for Waiver and Clarification of the United States Telecom Association, the Independent Telephone and Telecommunications Alliance, the National Telecommunications Cooperative Association, the Organization for the Promotion and Advancement of Small Telecommunications Companies, the Western Telecommunications Alliance, and the Eastern Rural Telecom Association, WC Dkt. Nos. 11-42 *et al.* CC Dkt. No. 95-45 (filed Mar. 9, 2012).

carrier that is receiving high-cost support. Therefore, to clarify that the federal Link Up subsidy is only available to residents of Tribal lands, the Commission shall amend Rule R9-6 as follows:

> (f) Pursuant to federal regulations, the LUC connection fee subsidy program is only available to residents of Tribal lands subscribing to service from an eligible telecommunications carrier that is receiving high-cost support.

In addition, to accommodate those carriers that have filed tariffs to implement the Link Up changes adopted in the Lifeline Reform Order prior to this date, the effective date of the amendment shall be April 2, 2012.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the _3rd__ day of May 2012 *nunc pro tunc* April 2, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Lh050212.01

DOCKET NO. P-100, SUB 133f

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Amendment to Commission Rule R9-6 to Implement	)	
Changes Required by the Lifeline and Link Up	)	ERRATA ORDER
Reform and Modernization Order	)	

BY THE COMMISSION: On May 3, 2012, the Commission issued an Order Amending Commission Rule R9-6 with the effective date of the amendment being April 2, 2012, in the above-captioned docket. It has come to the Commission's attention that the May 3, 2012 Order failed to note that Commissioner Susan W. Rabon did not participate in the proceeding. The Order should have indicated that Commissioner Susan W. Rabon did not participate.

The Commission, therefore, finds good cause to issue this Errata Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the _3rd__day of May, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Bh050312.01

DOCKET NO. P-100, SUB 133f

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Lifeline and Link-Up Services Pursuant to Section 254 of the Telecommunications Act of 1996	))))	ORDER AMENDING PARTICIPATION IN THE LIFELINE AND LINK-UP PROGRAMS AND AMENDING COMMISSION RULE R9-6

BY THE COMMISSION: On May 8, 1987, the Federal Communications Commission (FCC) issued its Report and Order, FCC Order No. 96-45 (Universal Service Order or USO) implementing key portions of Section 254 of the Telecommunications Act of 1996 (TA96) including changes to the Lifeline and Link-Up programs. The Commission addressed Lifeline issues in Docket No. P-100, Sub 80 and Link-Up issues in Docket No. P-100, Sub 95. The subsidy program for local service rates began as the "Interstate Subscriber Line Charge Waiver Mechanism" under the federal lifeline assistance program in Docket No. P-100, Sub 80 and was enacted by Commission Order on February 24, 1986. The Link-Up program, Link-Up Carolina (LUC), was initiated by Commission Order and promulgated by Commission Rule R9-6 on December 22, 1987. The Commission in its *Order Requiring Expanded Lifeline and Link-Up Services, dated November 5, 1997,* established Docket No. P-100, Sub 133f to deal with Lifeline and Link-Up issues pursuant to the USO. Since that time, revisions and amendments to the Lifeline and Link-Up programs, including Link-Up rule changes, have been promulgated by Commission Order in Docket No. P-100, Sub133f.

On February 6, 2012, the FCC released the Lifeline and Link-Up Reform and Modernization Order (the Lifeline Reform Order) which adopts changes in the Lifeline and Link-Up programs. The criterion to participate in the Lifeline and Link-Up programs was changed to include consumers with household income at or below 135% of the Federal Poverty Guidelines. Also included in the criteria to participate in Lifeline and Link-Up is the addition of participants in the National School Lunch Program's free lunch program[1]. Also, several additional assistance programs apply to low-income consumers living on Tribal lands. The FCC stated in the Lifeline Reform Order that, " We amend our rules to require all states to utilize, at a minimum, the income and program criteria currently utilized by federal default states[2]. In doing so, we establish baseline eligibility requirements on top of which states may adopt additional

[1] Federal programs qualifying low-income consumers for participation in the Lifeline and Link-Up programs are: A consumer's household with income which must be at or below 135% of the Federal Poverty Guidelines, or a consumer must participate in one of the following federal assistance programs: Medicaid; Supplemental Nutrition Assistance Program (SNAP), formerly known as Food Stamps; Supplemental Security Income (SSI); Federal Public Housing Assistance (Section 8); Low-Income Home Energy Assistance Program (LIHEAP); National School Lunch Program's free lunch program; and Temporary Assistance for Needy Families (TANF). Low-income consumers living on Tribal lands may also qualify by participation in one of several additional assistance programs: Bureau of Indian Affairs general assistance; Tribally-administered TANF; Head Start (only those households meeting its income-qualifying standard); or Food Distribution Program on Indian Reservations (FDPIR). *See* 47 C.F.R. § 54.409(c).

[2] North Carolina was not cited as a federal default state in the FCC Notice of Proposed Rulemaking, CC Docket No. 96-45 released March 4, 2011.

program or income criteria to address the unique circumstances facing consumers in their states". The addition in qualifying programs for consumers to participate in the Lifeline program criteria was to begin with April 2012 disbursements. On May 1, 2012, the FCC issued a Public Notice which delayed the implementation date for the regulations implementing changes to the Lifeline program to June 1, 2012. However, the criterion to participate in the Link-Up program, which is now restricted to Indian tribal lands, was effective on April 2, 2012. The effective dates for these changes are April 2, 2012, for Link-Up and June 1, 2012, for Lifeline.

Based on the aforementioned changes for participation in the Link-Up program the Commission shall amend Rule R9-6 as follows:

> (2) In order to be eligible for assistance, a residential subscriber must be a **consumer with household income at or below 135% of the Federal Poverty Guidelines**, or a residential subscriber must be a current recipient of: Medicaid; Supplemental Nutrition Assistance Program (SNAP), formerly known as Food Stamps; Supplemental Security Income (SSI); Federal Public Housing Assistance Section 8); Low-Income Home Energy Assistance Program (LIHEAP); **National School Lunch Program's free lunch program**; **Tribally-administered TANF; Head Start (only those households meeting its income-qualifying standards); or Food Distribution Program on Indian Reservations (FDPIR).**

Furthermore, the aforementioned criteria to participate in the Lifeline and Link-Up programs by participation in the respective federal qualifying programs are herein adopted for Lifeline and Link-Up benefits. The effective dates for these changes are April 2, 2012, *nunc pro tunc* for Link-Up and June 1, 2012, for Lifeline.

The Lifeline/Link-Up Task Force (Task Force) filed its Semi-Annual Report filed with the Commission on February 15, 2012. The Commission notes that in addressing the Lifeline Reform Order, the Task Force stated that, "Members of the Task Force will meet and discuss the effect of the changes on Lifeline/Link-Up efforts in North Carolina and make a report in July".

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of June, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioner Lucy T. Allen did not participate in this decision.

mr062512.01

DOCKET NO. P-100, SUB 169

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Provision of Communications Service	)	ORDER PROMULGATING
By Cities Under G.S. 160A-340	)	RULE R23-1 THROUGH R23-5

BY THE COMMISSION: On May 9, 2011, the General Assembly ratified Session Law 2011-84, House Bill 129 (S.L. 2011-84 or H129), entitled "An Act to Protect Jobs and Investment by Regulating Local Government Competition with Private Business", and the bill became law on May 21, 2011. H129 primarily amended Chapter 160A of the General Statutes by adding a new Article 16A entitled "Provision of Communications Service by Cities."

The new law involves the Commission in two respects. First, G.S. 160A-340.2(b) provides in pertinent part:

> The provisions of G.S. 160A-340.1, 160A-340.4, and 160A-340.5 do not apply to the provision of communications service in an unserved area. A city seeking to provide communications service in an unserved area *shall petition the North Carolina Utilities Commission* for a determination that an area is unserved…. Any private communications service provider, or any other interested party, may, within a time established by order of the Commission, which time shall be no fewer than 30 days, file with the Commission an objection to the designation on the grounds that one or more areas designated in the petition is not an unserved area or that the city is not otherwise eligible to provide the service…. (Emphasis added.)

Second, Section 2(a) of the law amends G.S. 62-3(23) by adding a new subdivision to read: "l. The term 'public utility' shall include a city or a joint agency under Part 1 of Article 20 of Chapter 160A of the General Statutes that provides service as defined in G.S. 62-3(23)a.6. *and is subject to the provisions of G.S. 160A-340.1."* (Emphasis added).

On July 22, 2011, the Commission in an Order Seeking Comments asked the Public Staff to file initial comments setting forth proposed rules and procedures, to be followed by comments from interested parties. The Public Staff was given the opportunity to file reply comments to such comments. Copies of the Order Seeking Comments were sent to all local exchange companies (LECs), all competing local providers (CLPs), the North Carolina League of Municipalities, the Competitive Carriers of the South, Inc. (CompSouth), the North Carolina Telecommunications Industry Association, Inc. (NCTIA), and the North Carolina Cable Telecommunications Association (NCCTA).

INITIAL COMMENTS BY THE PUBLIC STAFF

The Public Staff filed comments on October 3, 2011, and analyzed the issues in this docket as set forth below. The Public Staff also provided a set of proposed rules specific to the subject matter entitled "Chapter 23. Provision of Communications Services by Cities."

1. Determination of an unserved area. G.S. 160A-340.2(b) provides in part:

> A city seeking to provide communications service in an unserved area shall petition the North Carolina Utilities Commission for a determination that an area is unserved. The petition shall identify with specificity the geographic area for which the designation is sought. Any private communications service provider, or any other interested party, may, within a time established by order of the Commission, which time shall be no fewer than 30 days, file with the Commission an objection to the designation on the grounds that one or more areas designated in the petition is not an unserved area or that the city is not otherwise eligible to provide the service.

The subsection goes on to define the term "unserved area" as "a census block, as designated by the most recent census of the U.S. Census Bureau, in which at least fifty percent (50%) of households either have no access to high-speed Internet service or have access to high-speed Internet service only from a satellite provider." High-speed Internet access service is defined in G.S. 160A-340(4) as "[i]nternet access service with transmission speeds that are equal to or greater than the requirements for basic broadband tier 1 service as defined by the Federal Communications Commission for broadband data gathering and reporting."

To address petitions filed by a city seeking to provide communication services in an unserved area, the Commission must (a) develop a procedural framework, (b) establish a procedure for handling objections, and (c) determine whether the area proposed to be served is an unserved area within the meaning of the Act.

The Public Staff did not suggest the use of any particular form for the petition. Instead, the Public Staff recommended that the form should simply comply with the requirements of Commission Rule R1-5 (Pleadings, generally) and provide sufficient information to demonstrate to the Commission that the area in question meets the definition of unserved area. The Public Staff's proposed rule also requires that the petition include the following information:

- A description of each census block proposed to be included in the unserved area.
- Information on the current availability of high-speed Internet access service at the household level in the proposed unserved area.
- A letter or resolution in support of the determination from the appropriate governing body that is filing the petition.

In addition, the Commission or Public Staff may request additional information as needed.

With regard to objections, the Public Staff noted that it is unclear whether 30 days starts upon the filing of the petition with the Commission, or upon the Commission's determination that an area is unserved. The Public Staff recommended that the Commission, upon the filing of the petition, issue an order giving notice that a petition for a determination of an unserved area has been filed and that persons who wish to file an objection to the petition must file the objection within 30 days of the date of the order.

The proposed rule provides that if an objection to the designation is filed, the Commission will schedule a proceeding and provide notice to the petitioner and to any objecting party. The Commission may also schedule a hearing and require notice of the hearing to be published by the petitioner. After the hearing or proceeding, the Commission will enter an order making the determination whether an area is unserved.

If no objection is filed within the time specified and the Commission does not order a hearing on its own initiative, the Commission will enter an order making the determination whether an area is unserved.

The Public Staff believes that the definitions provided in the Act in G.S. 160A-340 are sufficiently clear to provide the Commission with a basis for making a determination of an unserved area. The definitions are incorporated by reference in proposed Commission Rule R23-2.

2. **Notice of Proposals to Provide Communications Service.** G.S. 160A-340.3 provides in part:

> A city or joint agency that proposes to provide communications service shall hold not fewer than two public hearings, which shall be held not less than 30 days apart, for the purpose of gathering information and comment. Notice of the hearings shall be published at least once a week for four consecutive weeks in the predominant newspaper of general circulation in the area in which the city is located. The notice shall also be provided to the North Carolina Utilities Commission, which shall post the notice on its Web site, and to all companies that have requested service of the notices from the city clerk. The city shall deposit the notice in the U.S. mail to companies that have requested notice at least 45 days prior to the hearing subject to the notice.

The Public Staff noted that this provision does not apply to cities or joint agencies that are already providing communications services and are specifically exempted pursuant to G.S. 160A-340.2(c), but it does apply to cities that are seeking to provide communications service in an unserved area and to cities that are seeking to expand or provide service in other areas.[1] The Public Staff noted that the role of the Commission in this context is simply to post notice on its website. Although the Act does not specify how long the Commission must publish the notice, the Act provides that the notice must be deposited in the mail to companies that have requested notice at least 45 days prior to the first hearing. Thus, it seems to follow that the notice should be posted within a reasonable time following the filing of the notice and maintained on the Commission's website through the duration of the hearings, which must be not less than 30 days apart. Proposed Commission Rule R23-4 formalizes this requirement.

3. **Public utility status of cities or joint agencies providing communications services.** Section 2.(a) of the Act amends G.S. 62‑3(23) by adding the following new sub‑subdivision:

> I. The term "public utility" shall include a city or a joint agency under Part 1 of Article 20 of Chapter 160A of the General Statutes that provides service as defined in G.S. 62‑3(23)a.6. and is subject to the provisions of G.S. 160A‑340.1.

As pointed out by the Commission in its July 22, 2011, Order, entities that fall within the definition of a public utility pursuant to G.S. 62-3 are required to comply with the applicable provisions of Chapter 62, which include, but are not limited to, the utility franchise requirements (Article 6), regulation of rates (Article 7), fees and charges (Article 14), and penalties and actions (Article 15). The Public Staff agreed that cities that are subject to G.S. 160A-340.1 must therefore comply with all applicable requirements of Chapter 62. Cities that are subject to G.S. 160A-340.1 appear to include: (a) cities that propose to begin to provide communications services in an area that is not considered unserved; and (b) cities that are currently exempt pursuant to G.S. 160A-340.2(c), but wish to expand or extend their service territories.

The Public Staff particularly noted that, pursuant to G.S. 62-2(b1), the Commission does not regulate broadband service provided by public utilities as defined in G.S. 62‑3(23)a.6. There seems to be considerable overlap between the existing definition of "broadband service" in G.S. 62-3(1) and the definition of "communications service" established in the Act. In seeking to harmonize these statutes, the Public Staff proposed that a city that is subject to G.S. 160A-340.1 and provides communications service as described in G.S. 62-3(23)a.6., other than broadband service, be required to comply with the applicable requirements of Chapter 62. This requirement is formalized in its proposed Commission Rule R23-5.

Finally, cities and local agencies that are voice-over-Internet protocol or VoIP service providers are considered voice communications service providers pursuant to G.S. 62A-40(23) and therefore are required to collect and remit the charge for 911 service. A city or local agency

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[1] The Public Staff observed that notice requirements of G.S. 160A-340.3 also appear to apply to cities that meet the criteria of G.S. 160A-340.2(a) (cities that are seeking to purchase, lease, construct, or operate "facilities by a city to provide communications service within the city's corporate limits for the city's internal governmental purposes, including the sharing of data or voice between governmental entities for internal governmental purposes, or within the corporate limits of another unit of local government that is a party with the city to an interlocal agreement under Part 1 of Article 20 of Chapter 160A of the General Statutes for the provision of internal government services"). These types of services are partially excluded from the definition of "provision of communication service" in G.S. 160A-340(3), but there is some inconsistency between the language in the two provisions. This may have been a technical oversight on the part of the General Assembly.

that provides voice communications service pursuant to this Act would be subject to the provisions of Chapter 62A.

OTHER COMMENTS

The NCCTA was the only party to file comments in response to the Public Staff's comments. The NCCTA noted that it had been an active participant in the legislative process resulting in the enactment of S.L. 2011-84 and that its members have a direct and substantial interest in the matters addressed by it. While noting that the provisions of the Act are largely self-effectuating, the NCCTA observed that it impacts the Commission in three specific ways. First, it directs the Commission to post on its website any notice provided by a city of its intent to provide communication services covered by the Act. (G.S. 160A-340.3). Second, the Commission must issue a determination on any city's assertion that it seeks to provide communications service in an "unserved" area. (G.S. 160A-340.2(b)). Third, it is clarified that a city is subject to the regulatory authority of the Commission and is deemed to be a public utility to the extent it provides services covered by the Public Utilities Act (G.S. 62-3(23); S.L. 2011-84, at Section 2.(a)).

Website Notice Requirement. This is a relatively straightforward requirement intended to help ensure that providers and citizens are provided notice of potential governmental actions impacting their interests. The NCCTA added that, since the Commission's obligation here is merely to post notices that are provided, it is not necessary for the Commission to resolve interpretive issues raised by the Public Staff in its comments regarding the applicability of the notice requirement. *See* Public Staff Comments, p. 3, footnote 1.

The NCCTA recommended that, rather than merely treating the filings as a newly docketed matter, the Commission should post such notices directly on the Commission's homepage or under a separate link available on the Commission's homepage—for example, under a link labeled "City-owned communications providers notices of service" available under "NCUC News" or "Consumer Information" on the right-hand side of the homepage. These notices should also be recorded on the Commission's document inventory to facilitate dissemination of the notice.

In general, the NCCTA said it was in agreement with the Public Staff's proposed rule implementing the notice provision, with the exception of subsection (b) of the proposed Rule R23-4. This subsection states that notice under G.S. 160A-340.3 can be filed contemporaneously with a notice seeking determination of an "unserved area." The NCCTA does not believe that this provision correctly interprets the underlying statutory requirement for the following reasons:

First, the notice requirement is intended to provide notice to private providers during the investigation and feasibility stage of consideration of a proposal to provide communications services—that is, *before* a city takes definitive action to approve such a proposal. By contrast, the "unserved area" designation request can be made only *after* a city has complied with the necessary prerequisites required to secure the approval of a proposal to provide communications services. Thus, a city that has not taken action to approve a proposal to provide communications services cannot file an application for designation of an "unserved area" because the city has not taken the essential first step of approving the project in the first place.

Second, in order to move forward with a proposal to provide communications service, a city must comply with the public-private partnership provisions of G.S. 160A-340.6. If there is a private provider that is ready, willing and able to provide service in the area—even an "unserved area"—that provider should be given the opportunity to provide service under the public-private partnership provisions of G.S. 160A-340.6. Thus, it would be premature for a city to seek designation of an "unserved area" prior to obtaining authorization under G.S. 160A-343.3 and G.S. 160A-340.6.

Thus, the NCCTA argued that proposed Rule R23-4(b) conflicts with the specified provisions of S.L. 2011-84 as well as the basic principles of local governance and control. The proposed rule should either be revised to specify compliance with G.S. 160A-343.3 and G.S. 160A-340.6 prior to submitting an application for designation of an "unserved area" or the rule should be silent on the issue.

"Unserved Areas" Determinations. G.S. 160A-340.2(b) directs the Commission to issue a determination of a city's assertion that it seeks to provide communications service to an "unserved" area. The NCCTA is largely in agreement with the Public Staff's proposed rule to implement the provisions of this statute. However, the NCCTA would propose that the Commission afford 60 days, rather than 30 days, to file objections to a proposed designation request, as it has the discretion to do under the statute. The rationale for the longer period relates to the extra time it may take to collect and analyze new relevant information which may not be otherwise in the possession of a particular provider.

The NCCTA also proposed that the reference to a "proceeding" be substituted with reference to a "hearing" consistent with the process utilized by the Commission in contested cases.

Regulation of Cities as Public Utilities. Section 2.(a) of S.L. 2011-84 clarifies that a city is subject to the regulatory authority of the Commission and shall be deemed a public utility to the extent that it provides services covered by the Public Utilities Act.[1] The NCCTA does not believe that any new rules are necessary to effectuate Section 2.(a) or Section 6 of S.L. 2011-84. Cities that wish to provide services covered by Chapter 62 will be required to comply with the provisions of that Chapter, including obtaining a CLP and/or interexchange carrier (IXC) certificate as appropriate. Should the Commission determine that a rule to implement this provision is necessary, the proposed rule should be revised as set forth in the NCCTA's comments.

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[1] The NCCTA noted that one city, Pineville, is directly identified in the statutes as a public utility. *See* G.S. 62-3(23)f. Under Section 6 of S.L. 2011-84, Pineville continues to be regarded as a public utility under that provision but is not otherwise subject to the provisions of the Act with respect to its operations that are regulated under Chapter 62. The intention of this provision is to continue the scheme of regulation in place for Pineville prior to the Act with respect to the provision of telephone services, which will put Pineville on equal footing with the new cities that desire to provide telephone service in the future.

REPLY COMMENTS BY THE PUBLIC STAFF

Determination of an unserved area. The Public Staff had originally proposed a period of 30 days after the procedural order is issued for a private communications service provider or any other party to file any objections to the Commission's designation that the area is unserved. The NCCTA proposed that the Commission allow 60 days, and the Public Staff did not object.

Website Notice Requirement. The NCCTA had taken issue with the Public Staff's interpretation of the Act's provisions regarding the steps that a city must follow when seeking to provide communications service to an unserved area. The Public Staff had drafted a proposed Commission Rule R23-4(b) to allow a city to file a petition for determination of an unserved area pursuant to Rule R23-3 *contemporaneously* with the notice requirements under Rule R23-4. The NCCTA has argued that the Act requires a city to first complete the notice and hearing requirements under G.S. 160A-340.3 and the solicitation of public-private partnerships in G.S. 160A-340.6 prior to filing a petition for determination with the Commission. While the Public Staff agrees that these provisions apply to the process of seeking to provide service in an unserved area, it does not agree that the statute mandates that these steps must be completed *prior* to the Commission making an unserved area determination. The reason is the difference in wording between G.S. 160A-340.2(b) and 160A-340.3. G.S. 160A-340.2(b), concerning determination that the area is unserved, is keyed to a "city *seeking to provide* communications service" in such area, while G.S. 160A-340.3 concerning notice requirements, is keyed to "a city or joint agency *that proposes to provide* communications service." G.S. 160A-340.6.(a) says that "*[p]rior to undertaking to construct a communications network for the provision of communications service,* a city shall first solicit proposals…." (Emphasis added).

The Public Staff argued that there is no significant difference between a city "seeking to provide" and "a city that proposes to provide" communications service. However, the phrase "prior to undertaking to construct" seems to imply that the solicitation of proposals would occur after a city first seeks to provide communications service. There is no statutory basis to preclude a city from seeking an unserved area determination pursuant to G.S. 160A-340.2(b) prior to or contemporaneously with its compliance with the notice requirements of G.S. 160A-340.3.

Public utility status of cities providing communications services. The Public Staff noted that in its initial comments it had identified two categories of cities that are subject to G.S. 160A-340.1—namely, those cities that propose to begin to provide communications services in an area that is not considered unserved and those cities that are currently exempt pursuant to G.S. 160A-340.2(c) but wish to expand or extend the service territory of their communications services. Pursuant to the new G.S. 62-3(23)l., enacted as Section 2.(a) of the Act, these cities are included in the definition of public utility and must comply with all applicable requirements of Chapter 62.

The NCCTA states in Note 4 to its revision of the proposed Rule R23-5 that an exemption from public utility status for cities presently providing communications services is provided not in G.S. 160A-340.2 but rather in Section 6 of the Act. NCCTA would thus eliminate the citation to this section in the rule as the source for the exemption from public utility status for cities presently providing communications services and substitute a citation to "Section 6 of S.L. 2011-84. The Public Staff opposed this revision. In doing so, the Public Staff noted that while it agreed with NCCTA that Sections 5 and 6 of the Act provide an exemption for cities presently providing communications services, it disagrees with the assertion that G.S. 160A-340.1 does not provide an additional basis for exemption. Exemptions from G.S. 160A-340.1 are provided in G.S. 160A-340.2(a) (concerning the provision of communication services by a city for internal governmental purposes), G.S. 160A-340.2(b) (the provision of communications services by a city in an unserved area), and G.S. 160A-340.2(c) (a city that was providing communications service as of January 2011, as long as certain conditions are met). A city that is not subject to the provisions of G.S. 160A-340.1 by virtue of one or more of these exemptions would not be a public utility as defined in G.S. 62-3(23)l. Accordingly, the Public Staff disagreed with the NCCTA's recommendation that the citation to G.S. 160A-340.2 be stricken from the proposed Commission Rule R23-5.

Necessity of adopting rules to implement additional portions of the Act. On pages 3 and 7 of its comments, the NCCTA raises the question of whether it is necessary for the Commission to adopt rules related to aspects of the Act other than the process of making a determination of whether an area is unserved, as described in proposed Rule R23-3. While the Public Staff agreed that much of the statute is self-effectuating and rules may not be strictly necessary in this regard, the Public Staff believes that codification of the notice requirements proposed in Rule R23-4 and the statement of public utility status in Rule R23-5 may serve to resolve potential procedural questions related to the implementation of the Act.

DISCUSSION

In its comments, the NCCTA identified three key areas of disagreement with the original rule proposed by the Public Staff which have not been eliminated in the most recently revised rule proposed by the Public Staff. First, the NCCTA indicated that it disagreed with the provision of the proposed rule that permits a city seeking to provide communications services to file a petition for determination of an unserved area *contemporaneously* with the notice requirements that the Act requires a city to comply with if it desires to provide communications services. The NCCTA argued that S.L. 2011-84 requires a city desiring to provide communications services to give notice to private communication providers *"before"* a city takes definitive actions to approve a proposal to provide communication services and to give the same providers the opportunity to provide those services through a public-private partnership prior to petitioning the Commission to designate an unserved area. The NCCTA argued that G.S. 160A-340.3 and 160A-340.6, as well as basic principles of local governance and control, support its position that the city must give notice that it is seeking to provide communications service and that the city must give private providers the opportunity to provide necessary communication services even in areas that may be unserved *before* the city can petition the Commission to determine if an area is unserved.

In response to those arguments, the Public Staff pointed out that the General Assembly did not explicitly preclude a city from seeking an unserved area determination pursuant to G.S. 160A-340.2(b) prior to or contemporaneously with its compliance with the notice requirements of G.S. 160A-340.3 when it enacted S.L. 2011-84. In fact, the Public Staff argued, there is much to suggest that the procedure recommended in the proposed rule is not only permitted but contemplated by the Act.

According to the Public Staff, this construction is supported by the similarity in certain key respects between the language in G.S. 160A-340.2 and G.S. 160A-340.3, the sections dealing with the unserved area determination and notice requirements, respectively. G.S. 160A-340.2(b), the unserved area provision, refers to a "city *seeking to provide* communications service" in an unserved area petitioning the Commission for a determination that an area that it might wish to serve is unserved and therefore subject to service possibly without regulatory oversight, while G.S. 160A-340.3 concerning notice requirements, is keyed to "a city or joint agency *that proposes to provide* communications service." The Public Staff pointed out that there is very little difference in that language.

The Commission agrees with the Public Staff. Both phrases seem to suggest that the activity contemplated, i.e., the determination of whether an area is unserved or the notice that a city is proposing to provide communications service, is to be done while the city is contemplating whether and/or to what extent it should engage in the provision of communications services. Typically, both such activities occur during the information gathering stage *before* a concrete decision *to provide communication service* has been definitively made. By contrast, the language cited in G.S. 160A-340.6, the section dealing with public-private partnerships, states that "prior to undertaking to construct …, a city shall first solicit proposals…" This language implies that the necessary preliminary information that the previously cited sections were designed to solicit has been gathered, assessed and the decision has been made to provide communication services. Typically, this occurs *after* the information gathering has been completed.

In our view, it is logical to construe the language in the manner suggested by the Public Staff since such a construction would expedite rather than hinder the provision of communication services by either the city or through a public-private partnership to areas subsequently determined to be unserved. Moreover, such a construction would permit the city and the private provider to more accurately assess potential financial and service obligations prior to undertaking to construct or extend a communications network. Thus, we reject the NCCTA's objection to the provision in the proposed rule that allows a city to file a petition for determination of an unserved area pursuant to Rule R23-3 *contemporaneously* with the notice requirements under Rule R23-4.

Second, in Note 4 to its revision of the proposed Rule R23-5, the NCCTA stated that an exemption from public utility status for cities presently providing communications services is not provided in G.S. 160A-340.2 as contended by the Public Staff but in Section 6 of the Act. Because of this, the NCCTA suggested that the Proposed Rule be revised to eliminate the citation to this section and instead substitute a generic reference to "Section 6 of S.L. 2011-84" as the source of the exemption from public utility status for cities presently providing communications services. Similarly, in Note 5 to its revision of the proposed Rule R23-5, the NCCTA suggested that the citation to G.S. 62-2(b1) be eliminated in the Proposed Rule because it was not necessary and could be confusing since that particular section of the statute which provides that the Commission shall not regulate broadband does not operate as a general exclusion from all regulation.

In its Reply Comments, the Public Staff identified Section 5 as well as Section 6 of the Act as exemption sources for cities presently providing communications services. It also noted that additional bases for exemption are provided in G.S. 160A-340.2(a) (concerning the provision of communications services by a city for internal governmental purposes), G.S. 160A-340.2(b) (the provision of communications services by a city in an unserved area), and G.S. 160A-340.2(c) (a city that was providing communications service as of January 2011, as long as certain conditions are met). A city that is privy to one or more of these exemptions would not be a public utility as defined in G.S. 62-3(23)l. Accordingly, the Public Staff disagreed with the NCCTA's recommendation that the citation to G.S. 160A-340.2 be stricken from the proposed Commission Rule R23-5.

We agree with the Public Staff. While it is indeed correct that Section 6 of the Act explicitly exempts cities presently providing communications services from public utility status, the Act itself provides a more comprehensive offering detailing precisely the circumstances in which a city (or cities) which is (are) presently providing communications services are exempt from public utility status and the regulatory oversight that such a designation involves. For that reason, we see nothing confusing or wrong with the expansive exemption listing that the Public Staff's revision to the proposed rule has adopted and thus reject the limitation proposed by the NCCTA to Rule R23-5.

Finally, because much of the Act is self-effectuating, the NCCTA questioned the general necessity for the Commission to adopt rules related to aspects of the Act other than the process of making a determination of whether an area is unserved, as described in proposed Rule R23-3. The NCCTA observed that cities desiring to provide services covered by Chapter 62, the Public Utilities Act, will be required to comply with the provisions of the Chapter, including obtaining a Competitive Local Provider and/or interexchange carrier certificate as appropriate. While we agree that much of the Act is self-effectuating and that cities desiring to provide services covered by Chapter 62 of the Act will be required to comply with the provisions of the Chapter, we nevertheless believe that codification of the notice requirements proposed in Rule R23-4 and the statement of public utility status in Rule R23-5 may serve to resolve potential procedural questions related to the implementation of the Act.

Thus, after carefully considering the language of H129, the Public Staff's Comments and Recommendations, the Public Staff's Reply Comments, the NCCTA's Comments on the Public Staff's Proposed Rule, the revisions proposed to the rules by the NCCTA, and the original and revised rule proposed by the Public Staff, the Commission concludes that the Rule that is attached hereto as Appendix A shall be adopted. In adopting this Rule, the Commission notes that the rule that we have today adopted is identical to the Revised Rule proposed by the Public Staff as an attachment to its December 9, 2011 Reply Comments.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the _28th_ day of February, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Dl022812.01

APPENDIX A

Chapter 23
Provision of Communications Services by Cities

Rule R23-1 Application of this Rule
Rule R23-2 Definitions
Rule R23-3 Petition for determination of an unserved area; objections to determination
Rule R23-4 Notice of proposal to provide service
Rule R23-5 Public utility status of city-owned communications service provider

Rule R23-1 Application of this Rule
This Chapter exists to implement certain aspects of Session Law 2011-84, codified in large part in G.S. 160A-340, et seq., relating to this Commission's authority. This Chapter governs any city or joint agency that seeks to provide communications service in North Carolina, except as specifically exempted in S.L. 2011-84.

Rule R23-2 Definitions
(a) The term "city" shall be defined as provided in G.S. 160A-1(2).
(b) The following terms shall be defined as provided in G.S. 160A-340: "city-owned communications service provider"; "communications network"; "communications service"; "high-speed Internet access service"; "interlocal agreement"; and "joint agency".
(c) The terms "cable service", "telecommunications service", and "video programming service" have the same meanings as in G.S. 105-164.3.
(d) The term "unserved area" shall be defined as provided in G.S. 160A-340.2(b).

Rule R23-3 Petition for determination of an unserved area; objections to determination
(a) A city that proposes to provide communications service to an unserved area shall first file a petition with the Commission for a determination that the area is unserved.
(b) The petition shall comply with Commission Rule R1-5 and provide sufficient information to demonstrate to the Commission that the area in question meets the definition of "unserved area." In addition to the information required in Rule R1-5, the petition shall also include the following:
    (1) A description of each census block proposed to be included in the unserved area.
    (2) Information on the current availability of high-speed Internet access service at the household level in the proposed unserved area.

(3) A letter or resolution in support of the determination from the appropriate governing body that is filing the petition.

(c) The Commission or Public Staff may request additional information as needed.

(d) Procedure upon receipt of Petition – Upon the filing of a petition that meets the requirements set forth above:

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(1) The Commission will issue a procedural order stating that a petition for a determination of an unserved area has been received and that parties who wish to file an objection to the petition must file the objection in writing and in compliance with the provisions of Rule R1-5 within 60 days of the date of the procedural order. The Commission shall also post the procedural order on its website.

(2) Upon its own initiative, the Commission may schedule a hearing to determine whether a determination should be made and require notice of the hearing to be published by the petitioner in the newspaper in the county or counties where the proposed unserved area is located.

(3) If an objection is filed within 60 days of the procedural order, the Commission will schedule a hearing to consider whether a determination should be made and will give reasonable notice to the petitioner and to each objecting party. Following the hearing, the Commission will enter an order making the determination whether an area is unserved.

(4) If no objection is filed within the time specified, the Commission shall enter an order making the determination whether an area is unserved.

(e) No city shall begin providing communications service in an unserved area prior to receiving a determination from the Commission that the area is unserved.

Rule R23-4 Notice of proposal to provide service

(a) Upon filing of a notice by a city or joint agency that proposes to provide communications services pursuant to G.S. 160A-340.3, the Commission shall post the notice of the proposal on the Commission's website. The notice must be filed with the Commission at least 45 days prior to first hearing scheduled in the notice and shall remain available on the Commission’s website through the duration of the public hearings scheduled in the notice.

(b) A city may file a petition for determination of an unserved area pursuant to Commission Rule R23-3 contemporaneously with the notice requirements of this rule.

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Rule R23-5 Public utility status of city-owned communications service provider

Except as provided in Sections 5 and 6 of S.L. 2011-84, G.S. 160A-340.2, and G.S. 62-2(b1), a city or joint agency that provides service as defined in G.S. 62-3(23)a.6. is a public utility and shall comply with all applicable provisions of the Public Utilities Act and all applicable rules and regulations of the Commission.

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 FOR ORDER) REGARDING TIMING AND FORM) OF TARIFF FILINGS BY ILECS) AND PROOF OF COMPLIANCE

BY THE COMMISSION: On May 16, 2012, the Public Staff filed a Motion for Order Regarding Timing and Form of Tariff Filings by Incumbent Local Exchange Companies (ILECs) and Proof of Compliance.

In its Motion, the Public Staff requested that the Commission order the ILECs to file workpapers supporting tariff revisions that are to be effective in July, 2012 based on the Federal Communications Commission's November 18, 2011 Universal Service Fund (USF) / Intercarrier Compensation (ICC) Transformation Order (also known as the Connect America Fund Order) by no later than June 1, 2012, and the revised tariffs no later than June 15, 2012. The Public Staff further requested that the Commission direct non-average schedule ILECs to use the applicable forms as prescribed by the FCC in its April 19, 2012 Tariff Review Plans Order (TRP Order) to support the revisions. The Public Staff asserted that ILECs need only submit information on those forms necessary to provide the requisite support for the proposed revisions to intrastate access service tariffs.

The Public Staff further noted that the FCC's USF/ICC Transformation Order directs state commissions to monitor compliance of carriers with the rate transition required by the USF/ICC Transformation Order. The Public Staff maintained that to monitor the compliance of average schedule companies[1] and competing local providers (CLPs) with the USF/ICC Transformation Order, the Commission should require all average schedule companies and CLPs to provide proof of compliance to the Commission by June 1, 2012[2].

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[1] The Public Staff noted that it understands the average schedule companies concurring in the National Exchange Carrier Association's (NECA's) interstate tariffs are Ellerbe Telephone Company, North State Communications, Service Telephone Company, and the Town of Pineville d/b/a Pineville Telephone Company.

[2] The Public Staff specified that an average schedule company or CLP with intrastate rates matching its interstate rates should file an affidavit indicating as such. The Public Staff further specified that if the interstate and intrastate rates do not match, the companies should provide proof of compliance, preferably the standardized ILEC worksheets provided by the FCC or similar format. The Public Staff stated that if these forms are not used, proof of compliance should, at a minimum, show five specific pieces of information as outlined on page 3 of the Public Staff's Motion.

The Public Staff noted that it had provided a draft of its Motion to the parties, but that the parties have not been able to reach a consensus. The Public Staff stated that as there is little more than two weeks until the first requested filing by carriers, the Public Staff would ask if the Commission determines that it should seek comments from the parties, any comment cycle be abbreviated.

Finally, the Public Staff noted that CLPs were not made party to the proceeding when this docket was initiated, and the Public Staff recommended that the Commission make each of the CLPs a party to this proceeding.

By Order dated May 18, 2012, the Commission requested initial and reply comments on the Public Staff's Motion and made each certified CLP a party to this proceeding.

Initial comments were filed on May 23, 2012 by BellSouth Telecommunications, LLC d/b/a AT&T North Carolina (AT&T North Carolina), the Competitive Carriers of the South Inc. (CompSouth) and the North Carolina Cable Telecommunications Association (NCCTA), the RLEC Coalition[1], and Sprint Communications Company L.P. (Sprint).

Reply comments were filed on May 24, 2012 by the Public Staff.

INITIAL COMMENTS

AT&T North Carolina stated that it supports the Public Staff's Motion.

AT&T North Carolina further stated that at the time the Public Staff filed its Motion, various parties were discussing their understanding of the effective date of the access reductions that are subject of this docket. AT&T North Carolina stated that it will not oppose an effective date of July 3, 2012 for such intrastate access reductions, provided that this effective date applies to the access reductions of all parties.

AT&T North Carolina also specifically noted that it supports the Public Staff's recommendation that average schedule companies and CLPs provide proof of compliance, preferably by the standardized ILEC worksheets provided by the FCC or a similar format. AT&T North Carolina maintained that it is in the best interest of each party and of the public, generally,

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[1] For purposes of the comments, the RLEC Coalition includes Citizens Telephone Company d/b/a Comporium, Ellerbe Telephone Company, North State Telephone Company d/b/a North State Communications, Barnardsville Telephone Company, Saluda Mountain Telephone Company, Service Telephone Company, Town of Pineville d/b/a Pineville Telephone Company, Frontier Communications of the Carolinas Inc., Carolina Telephone and Telegraph Company LLC d/b/a CenturyLink, Central Telephone Company d/b/a CenturyLink, MebTel, Inc. d/b/a CenturyLink, Windstream Concord Telephone, Inc., Windstream Lexcom Communications, Inc., Windstream North Carolina, LLC, as well as Atlantic Telephone Membership Corporation, Randolph Telephone Membership Corporation, Skyline Telephone Membership Corporation, Star Telephone Membership Corporation, Surry Telephone Membership Corporation, Tri-County Telephone Membership Corporation, Wilkes Telephone Membership Corporation, and The Yadkin Valley Telephone Membership Corporation.

to identify and resolve any issues relating to the intrastate access reductions as quickly as possible. AT&T North Carolina asserted that given the number of entities affected, however, it would be difficult if not impossible to quickly review supporting documentation and identify any issues if each party used its own method of creating and providing supporting documentation. AT&T North Carolina stated that the Public Staff's proposal, therefore, appropriately facilitates an expedited review and consideration of supporting documentation on an apples-to-apples basis, which in turn will assist the parties, the Public Staff, and the Commission in quickly identifying and resolving any issues with the intrastate access reductions.

Finally, AT&T North Carolina stated that it is not opposed to any party filing additional support for related restructure calculations. AT&T North Carolina noted that it is aware that one or more non-average schedule ILECs may intend to restructure their local transport rates and that such ILECs may desire to supplement the forms and worksheets prescribed by the FCC in its TRP Order to provide support for their transport restructure calculations. AT&T North Carolina maintained that it has no objection to such an ILEC filing supplementary support in additional to the applicable forms as prescribed by the FCC's TRP Order.

CompSouth and the NCCTA noted that the Public Staff, in its Motion for Order Regarding Timing and Form of Tariff Filings by ILECs and Proof of Compliance, made recommendations concerning the Commission's review of certain tariff revisions required under the FCC's USF/ICC Transformation Order. CompSouth and the NCCTA stated that, in general, effective July 1, 2012, carriers are required to implement rate reductions such that intrastate terminating switched end office and transport rates, originating and terminating dedicated transport, and reciprocal compensation rates, if above the carrier's interstate access rate, are reduced by 50 percent of the differential between the rate and the carrier's interstate access rate.

CompSouth and the NCCTA stated that they support the recommendations of the Public Staff in its Motion as they pertain to price cap and average schedule ILECs but not as they pertain to CLPs. CompSouth and the NCCTA believe that the Public Staff's recommendation to require CLPs that are not at parity with interstate rates to submit detailed workpapers is over-regulatory, will lead to unnecessary disputes, and is not required to comply with the Commission's responsibilities under the USF/ICC Transformation Order.

CompSouth and the NCCTA argued that there are substantive regulatory and operational differences between average schedule incumbent ILECs and CLPs which require differentiations in the way the Commission discharges its oversight function as to these entities. CompSouth and the NCCTA noted further that, as of July 1, 2011, there were 186 certified CLPs in this state. CompSouth and the NCCTA asserted that given that CLPs offer, by definition, competitive services, their operations differ greatly and many do not offer traditional switched access services. CompSouth and the NCCTA argued that requiring workpapers from each of these entities will cause unnecessary confusion among this large group of disparately situated carriers and create a compliance hurdle that is not grounded in an important regulatory need.

CompSouth and the NCCTA maintained that the analysis proposed by the Public Staff is appropriate for ILECs which are permitted to maintain tariffs in North Carolina and which are entitled to participate in the revenue recovery mechanisms established by the FCC in the USF/ICC Transformation Order. CompSouth and the NCCTA asserted that CLPs, however, are not permitted to maintain tariffs in North Carolina nor are they permitted to participate in the FCC's revenue recovery mechanisms. CompSouth and the NCCTA argued that there is no precedent in North Carolina for CLPs filing detailed worksheets of the nature proposed by the Public Staff.

CompSouth and the NCCTA noted that the Public Staff conceded that CLPs with intrastate rates already at parity may simply submit an affidavit indicating as such. CompSouth and the NCCTA maintained that a certification approach is the appropriate approach for all CLPs, regardless of whether their rates are currently at parity. CompSouth and the NCCTA asserted that because CLPs are not permitted to maintain tariffs in North Carolina, and, accordingly, there is no tariff for the Public Staff to review, the "workpaper" approach for CLPs is simply a more burdensome form of certification. CompSouth and the NCCTA argued that, moreover, any certification required of CLPs should be directed only to those intrastate terminating switched access and other rates that are the subjects of the July 1, 2012 reductions.

CompSouth and the NCCTA stated that, although the USF/ICC Transformation Order delegates a review and compliance function to state commissions, state commissions retain flexibility in discharging this function. CompSouth and the NCCTA maintained that, for example, FCC Rule § 51.909(k) explicitly acknowledges the "authority of a state to monitor and oversee filing of intrastate tariffs" for average schedule companies, while FCC Rule § 51.911(a) which is applicable to CLPs merely states that CLPs "shall remain subject to the same state regulation in effect December 31, 2011… " CompSouth and the NCCTA stated that, in other words, as reflected in the FCC's rules, the fact that the FCC has adopted pricing requirements applicable to CLPs does not alter this Commission's traditional regulatory approach to competitive providers, which, to date, has consistently been a deregulatory approach. CompSouth and the NCCTA asserted that given that the Commission has never performed a "monitor and oversight" role over CLP tariffs, there is nothing in the USF/ICC Transformation Order that requires the Commission to now perform such a function. CompSouth and the NCCTA argued that should questions arise in the future with regard to a particular CLP's compliance with the rate requirements of the USF/ICC Transformation Order, the Commission retains complaint authority to review the CLP's rates and address the complaint. CompSouth and the NCCTA maintained that as to CLPs, there is no need or basis for any greater review of oversight of CLP compliance.

CompSouth and the NCCTA requested that CLPs be permitted to submit a compliance statement in lieu of the detailed worksheet information proposed by the Public Staff.

The RLEC Coalition stated that it supports the Public Staff's Motion and appreciates it efforts to ensure an orderly and transparent tariff filing process.

The RLEC Coalition, however, wished to clarify two areas of the Public Staff's Motion regarding: (1) the effective date of revised intrastate access service tariffs; and (2) the types of supporting worksheets to be provided to the Commission to the extent a non-average schedule ILEC restructures its local transport rates.

The RLEC Coalition maintained that revised intrastate access service tariffs should be effective July 3, 2012. The RLEC Coalition stated that when the Public Staff circulated its draft Motion to the parties, a question arose as to the proper effective date for revisions to intrastate access tariffs. The RLEC Coalition asserted that the Public Staff's Motion does not explicitly set a July 1, 2012 effective date for revised intrastate access service tariffs, but it is silent on this point. The RLEC Coalition argued that on March 28, 2012, the FCC moved the effective date for both interstate and intrastate access service tariffs from July 1, 2012 to July 3, 2012. Accordingly, the RLEC Coalition requested that the Commission order intrastate access service tariff revisions to be effective July 3, 2012.

The RLEC Coalition noted that in the USF/ICC Transformation Order, the FCC determined, among other things, that intrastate terminating end office rates are to be reduced to parity with interstate rates in two phases, effective July 1, 2012 and July 1, 2013. The RLEC Coalition maintained that the July 1, 2012 date was codified in the regulations for price cap carriers at 47 C.F.R. §51.907(b) and for rate-of-return carriers at 47 C.F.R. § 51.909(b); however, a waiver of the July 1, 2012 effective date was authorized in the FCC's Order dated March 28, 2012.

The RLEC Coalition stated that the FCC's March 28, 2012 Order at Footnote No. 3 specifically permits price cap carriers and rate-of-return carriers to have an effective date of July 3, 2012 rather than July 1, 2012 on their transitional interstate access rates. The RLEC Coalition maintained that the FCC stated in Footnote No. 3 of its March 28, 2012 Order that "[t]o establish a filing date of July 3, 2012, we therefore grant a limited waiver of 47 C.F.R. §§ 69.3(a), 51.705, 51.907, and 51.909 of our rules to the extent that those rules would otherwise require rates to be effective as of July 1, 2012." The RLEC Coalition specified that the FCC waiver identified in Paragraph 2 of the FCC's March 28, 2012 Order applies to § 51.907(b) which deals with the transition of price cap carrier intrastate access charges, and § 51.909(b), which deals with the transition of rate-of-return carrier intrastate access charges.

The RLEC Coalition maintained that the ordering clause of the FCC's March 28, 2012 Order specifies that the waiver is applicable to several FCC regulations, including § 51.907(b) and § 51.909(b). The RLEC Coalition asserted that the only July 1 effective date mentioned in either § 51.907(b) or § 51.909(b) is the July 1, 2012 effective date for state tariff filings, and there is no reference whatsoever to interstate tariff filing requirements in these sections. The RLEC Coalition stated that, thus, the limited waiver granted in the FCC's March 28, 2012 Order includes a limited waiver of the rules requiring that intrastate access rate reductions be effective July 1, 2012, and both price cap carriers and rate-of-return carriers are to make Year 1 access and non-access rate reductions effective July 3, 2012.

The RLEC Coalition further argued that the use of the July 3, 2012 effective date of the tariff is also consistent with the FCC's adoption of the Access Recovery Charge (ARC) and maintains the fundamental tie between the timing of state access charge reductions and the timing of the federal ARC implementation. The RLEC Coalition noted that in Paragraph 847 of the USF/ICC Transformation Order, the FCC adopted a transitional recovery mechanism to facilitate ILECs' gradual transition away from intercarrier compensation revenues reduced as directed in that Order. The RLEC Coalition maintained that ILECs are permitted to recover the loss in access revenues through limited end-user charges, called the ARC. The RLEC Coalition noted that if these charges are insufficient, carriers will be entitled to Connect America Fund (CAF) support equal to the remaining eligible recovery.

The RLEC Coalition maintained that the FCC's March 28, 2012 Order clearly recognized that, if it was going to establish a July 3, 2012 effective date for federal annual tariff filings and the new ARC, it needed to allow for a July 3, 2012 effective date for state access charge reductions. The RLEC Coalition asserted that if the ARC cannot be made effective until July 3, 2012, yet ILECs are forced to file revised intrastate access tariffs on July 1, 2012, there are two days for which they would be unable to recover the ARC, which is contrary to the intent of the USF/ICC Transformation Order. The RLEC Coalition argued that it was the intent of the USF/ICC Transformation Order to offset the access reductions with the ARC. The RLEC Coalition stated that, as such, this explains why the FCC would synchronize the filing of the interstate and intrastate tariffs, and demonstrates the importance of having an effective date of July 3, 2012 for intrastate access tariff revisions.

The RLEC Coalition noted that some parties allege that the FCC's March 28, 2012 Order applies only to interstate tariff filings at the FCC. The RLEC Coalition argued that this very narrow reading of the FCC's March 28, 2012 Order ignores the fact that the Order specifically waives the July 1, 2012 date in Sections § 51.907(b) and § 51.909(b). The RLEC Coalition asserted that these sections specifically relate to the transitional intrastate access rates for price cap and rate-of-return carriers. The RLEC Coalition maintained that if Sections § 51.907(b) and § 51.909(b) were not subject to the waiver then the references to these rules in the ordering clauses from the FCC's March 28, 2012 Order would be rendered meaningless. The RLEC Coalition argued that such a narrow interpretation of the FCC's March 28, 2012 Order would ignore the imbalance created by the loss of access revenues, and the inability to recover some of this loss through the ARC, as contemplated by the USF/ICC Transformation Order.

The RLEC Coalition further commented that non-average schedule company ILECs should be permitted to supplement forms prescribed by the TRP Order to the extent they restructure local transport rates. The RLEC Coalition noted that the Public Staff's Motion requires non-average schedule ILECs to use the applicable forms as prescribed by the FCC in its TRP Order to support their respective tariff revisions. The RLEC Coalition argued that some non-average schedule ILECs have not yet restructured their respective local transport rates, but may plan to do so in conjunction with the upcoming tariff filings. The RLEC Coalition asserted that to the extent a non-average schedule ILEC restructures its local transport rates, the RLEC Coalition respectfully requests that such an ILEC be permitted to supplement the forms and worksheets prescribed by the FCC in the TRP Order to provide support for its transport restructure calculations.

The RLEC Coalition concluded that it generally supports the Public Staff's Motion, however, requested that the Commission clarify the Public Staff's Motion: (1) to allow revised intrastate access tariff revisions to be effective July 3, 2012; and (2) to the extent a non-average schedule ILEC restructures its local transport rates, that such an ILEC be permitted to supplement the forms prescribed by the TRP Order to support its calculations.

Sprint maintained that it supports the Public Staff's Motion. Sprint asserted that it strongly believes that in addition to the access providers, the Public Staff and the Commission Staff, all payers of North Carolina intrastate access charges such as Sprint should be allowed to review the confidential data supporting the ILECs' access reduction tariff filings. Sprint commented that a comprehensive review of the relevant confidential supporting data by all interested parties will ensure that the ILECs' FCC-mandated tariff revisions are accurate and that the review process is transparent and open.

Sprint requested that the Commission grant the Public Staff's Motion in its entirety.

REPLY COMMENTS

The **Public Staff** stated that in regard to the question of whether the effective date of the transitional reductions in intrastate switched access rates is July 1 or July 3, 2012, as discussed in the comments of the RLEC Coalition and AT&T, the Public Staff does not oppose a July 3, 2012, effective date, based on the explanation provided by the RLEC Coalition. The Public Staff stated that it also finds the proposal of the RLEC Coalition that ILECs be allowed to file additional support for any proposed restructure calculations to be reasonable.

The Public Staff noted that G. S. § 62-133.5(j) grants the Commission jurisdiction over all matters concerning switched access and intercarrier compensation of all ILECs and CLPs operating in North Carolina. The Public Staff stated that, in the past, the Commission has not elected to require tariff filings by CLPs. The Public Staff commented that, however, Paragraph 813 of the FCC's USF/ICC Transformation Order directs the Commission to monitor compliance of carriers with the rate transition prescribed therein and to "review how carriers reduce rates to ensure consistency with the uniform framework." The Public Staff asserted that the use of the words "monitor" and "review" indicate that the Commission should take an active role in ensuring that ILECs and CLPs operating in North Carolina comply with the USF/ICC Transformation Order. The Public Staff argued that for the Commission to carry out this overseer function, it is necessary that CLPs provide supporting documentation demonstrating compliance with the FCC Order. The Public Staff maintained that the FCC has not lowered the bar in regard to the compliance required by CLPs, and neither should this Commission.

The Public Staff asserted that, further, the data that CLPs would have to provide to demonstrate their compliance, i.e., units of demand for the intrastate rate elements affected; the intrastate rates and comparable interstate rates, price-outs, and the required change in intrastate revenues, should be data that each CLP has readily at hand, regardless of differences in operations. The Public Staff maintained that it is not requesting that the Commission impose any new tariff filing requirements on CLPs, but simply that the CLPs provide support showing that the intrastate rates to be charged on July 3, 2012, comply with the FCC's new rules. The Public

Staff asserted that it commits to work with each carrier to assist it in providing the necessary data.

The Public Staff noted that CompSouth and the NCCTA commented that some CLPs do not provide switched access services. The Public Staff maintained that, to the extent a CLP does not provide switched access service, the Public Staff believes an affidavit to that effect would suffice.

In regard to CompSouth's and the NCCTA's contention that any certification be directed only at intrastate terminating switched access and other rates subject to the reductions mandated by the USF/ICC Transformation Order, the Public Staff stated that it agrees.

The Public Staff recommended that the Commission: (1) order the non-average schedule ILECs to file workpapers supporting tariff revisions pursuant to the USF/ICC Transformation Order by June 1, 2012, using the forms adopted by the FCC in its TRP Order to support the proposed revisions; (2) order average schedule ILECs or CLPs with intrastate switched access rates at parity with their interstate rates to file an affidavit by June 1, 2012, indicating that the rates are the same; (3) order average schedule companies or CLPs with interstate and intrastate rates that vary to provide by June 1, 2012, proof of compliance with the USF/ICC Transformation Order, preferably the standardized ILEC worksheets provided by the FCC or similar format. If these forms are not used, proof of compliance should, at a minimum, include the items listed on Page 3 of the Public Staff's May 16, 2012 Motion; (4) order any ILEC seeking to restructure its intrastate switched access rates provide all necessary supporting documentation by June 1, 2012, to support such restructured rates; (5) order CLPs that do not provide switched access service to file an affidavit by June 1, 2012, indicating as such; and (6) order ILECs to file revised tariffs by June 15, 2012, reflecting the proposed rates to become effective July 3, 2012.

DISCUSSION

After carefully reviewing the Public Staff's Motion and the comments submitted on the Motion, the Commission finds it appropriate to grant the Public Staff's Motion. It also appears from the comments filed that three issues have been raised which specifically warrant a discussion and decision from the Commission.

First, it appears that all of the parties are generally in agreement that it is appropriate for the tariffs to become effective on July 3, 2012. Therefore, the Commission concludes that intrastate access tariffs filed in compliance with the FCC's USF/ICC Transformation Order shall be effective July 3, 2012.

Second, as requested by the RLEC Coalition, and not opposed by AT&T and agreed to by the Public Staff, the Commission finds it appropriate to specify that to the extent a non-average schedule ILEC restructures its local transport rates, such an ILEC is permitted to supplement the forms and worksheets prescribed by the FCC in the TRP Order to provide for its transport restructure calculations. Therefore, any ILEC seeking to restructure its intrastate switched access rates must provide all necessary supporting documentation by June 1, 2012, to support such restructured rates.

Further, the Commission agrees with the Public Staff that having CLPs provide supporting data, although they are not required to file tariffs, which will demonstrate the CLP's compliance with the FCC's USF/ICC Transformation Order is necessary in order for the Commission to fulfill its obligations. The USF/ICC Transformation Order is precedent-setting in its adoption of intrastate access charge reductions, and, as part of the Order, state commissions were tasked with verifying carriers' compliance with the Order. The Commission believes it is reasonable under these circumstances to require the supporting data from CLPs as proposed by the Public Staff. CLPs that do not provide switched access service should file an affidavit by June 1, 2012, indicating as such.

In conclusion, the Commission finds that non-average schedule ILECs are required to file workpapers supporting tariff revisions pursuant to the USF/ICC Transformation Order by June 1, 2012, using the forms adopted by the FCC in its TRP Order to support the proposed revisions; average schedule ILECs or CLPs with intrastate switched access rates at parity with their interstate rates to file an affidavit by June 1, 2012, indicating that the rates are the same; average schedule companies or CLPs with interstate and intrastate rates that vary to provide by June 1, 2012, proof of compliance with the USF/ICC Transformation Order, preferably the standardized ILEC worksheets provided by the FCC or similar format. If these forms are not used, proof of compliance should, at a minimum, include the items listed on page 3 of the Public Staff's May 16, 2012 Motion; and ILECs are hereby required to file revised tariffs by June 15, 2012.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The Commission hereby grants the Public Staff's Motion with the additional clarifications as outlined above.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of May, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

bp052912.01

DOCKET NO. WR-100, SUB 7

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Rulemaking to Implement North Carolina Session Law 2009-279 (Senate Bill 661)	))	ORDER ADOPTING PERMANENT RULES

BY THE COMMISSION: On July 10, 2009, North Carolina Session Law 2009-279 (Senate Bill 661) was signed into law. The legislation provided that it would become effective on October 1, 2009.

On September 29, 2009, the Commission issued an Order Initiating Rulemaking Proceeding in the matter. Said Order established new interim rules for use until adoption of final rules implementing the provisions of G.S. 62-110(g)(1a).

On October 15, 2009, the Public Staff filed the Public Staff's Comments. On October 16, 2009, the Apartment Association of North Carolina filed the Apartment Association of North Carolina's (AANC) Petition to Intervene. On December 12, 2011, the National Exemption Service (NES) sent an email regarding hot water multiplier calculations.

In its Comments, the Public Staff recommends that the last sentence in Commission Rule R18-6(a) be rewritten to clarify that the hot water capture, cold water allocation methodology was not prohibited. The Public Staff also notes that the statute does not include the words, "due to the plumbing configuration of the building." The Public Staff recommends that, in Rule R18-8, reference to Session Law 2009-279 be changed to G.S. 62-110(g)(1a). The Public Staff suggests that the use of the word "all" in the last line of the first paragraph in the rule should be "all of the" so that the phrase would read: "based upon the hot water usage of each tenant as a percentage of all of the tenants' hot water usage."

The Public Staff recommends that the Rule require "that information demonstrating that measurement of each tenant's total water usage would be impractical or not economical by rule and as part of the application" in order for the Commission to determine whether measurement of each tenant's total water usage is impractical or is not economical on a case-by-case basis.

The Public Staff notes that G.S. 62-110(g)(1a)(b) provides that a lessor shall not include in a tenant's bill the cost of water and sewer service used in common areas or water loss due to leaks in the lessor's water mains, but observed that the automatic 20% subtraction for common area usage and leakage from total water purchased proposed in Commission Rule R18-8 is not in the statute.

The AANC echoes the Public Staff's comment that the 20% figure used for subtraction of the common area usage and leakage is not part of G.S. 62-110(g)(1a). The AANC believes that the 20% figure is arbitrary and does not reflect the actual usage or leakage of its member communities. The AANC suggests that the Commission consider a more equitable system that relies primarily on actual, measured common area usage and leakage and requests that where such measured usage is unavailable, that the Commission craft a more graduated, tailored ratio that is property-specific to what systems, if any, are metered. The AANC recommends the following alternative methods to exclude common area usage:

1. Where all common areas are separately metered, subtract the actual common area usage from the total amount of water purchased.

2. Where common areas are not separately metered, subtract 15% from the total amount of water purchased where there is an installed landscape irrigation system.

3. Where there is an installed landscape irrigation system that is separately metered, subtract 5% from the total amount of water purchased where there are other common areas that are not separately metered, such as a pool or a laundry room.

4. Where there is no installed landscape irrigation system, subtract 5% from the total amount of water purchased where there are common areas that are not separately metered.

The AANC believes that such a system would be more equitable and would more closely reflect the apartment community owner's actual common area usage. The AANC indicated that it would work with its membership to obtain actual common area usage statistics from its membership in order to assist the Commission in establishing a more equitable system modeled after the one noted above.

The NES correspondence raised an issue regarding the Commission and conservation of resources in North Carolina. It asked, "What happens if a property feels that their common area is higher than 20% (their water usage for the Office/Clubhouse, pool(s), laundry room(s), hose bibs, etc. . .)?" Its experience in other jurisdictions indicates that the staff of a property tends to not be terribly concerned about their own water usage. The NES asked if it would be possible that the formula could be adjusted to compensate. It suggests (a) raising the common area removal to a reasonable level, or (b) would each point of common area need to be separately metered? It suggests that, based on the theme of the regulations, that (b) would be the preferred option.

G.S. 62-110(g) states, "In addition to the authority to issue a certificate of public convenience and necessity, and establish rates otherwise granted in this Chapter, for the purpose of encouraging water conservation, <u>the Commission may</u>, consistent with the public interest, <u>adopt procedures</u> that allow a lessor to charge for the costs of providing water and sewer service to persons who occupy the same contiguous premises." (Emphasis added.) Adopting procedures to implement the statute does not entail incorporating verbatim the statute – the statute speaks for itself and only repeating the statute in the Rules would serve no purpose.

G.S. 62-110(g)(1a)(b) states, "The lessor shall not include in a tenant's bill the cost of water and sewer service used in common areas or water loss due to leaks in the lessor's water mains." In the past, AANC has requested that the Commission practice "regulation lite" with respect to water resale regulations for its member communities. During the interval between adoption of G.S. 62-110(g)(1a) by the General Assembly and the adoption of the Interim Rules by the Commission, the Commission Staff had conversations with a number of stakeholders regarding potential rules and methodologies. Several stakeholders stated that, in other jurisdictions, common area usage was accounted for by subtraction of a set percentage (ranging from 15% to 25%) from the total usage. In an effort to comply with the statutory requirement that common area usage and leakage not be charged to the tenants and in an effort to provide "regulation lite", the Commission chose an automatic 20% subtraction for common area usage and leakage in order to keep regulation simple.

The NES correspondence reminds the Commission of the primary purpose of the water resale legislation – conservation. G.S. 62-110(g) states, "In addition to the authority to issue a certificate of public convenience and necessity, and establish rates otherwise granted in this Chapter, <u>for the purpose of encouraging water conservation</u>, the Commission may, consistent with the public interest, adopt procedures that allow a lessor to charge for the costs of providing water and sewer service to persons who occupy the same contiguous premises." (Emphasis added.) To that end, tenants should be given an opportunity to lower their water bills by using less water (i.e., conserving) and lessors should be able to pass on to the tenants more of the total cost of purchased water if the lessor uses less water (i.e., conserving) in the common areas. In consideration of the comments filed, the Commission is of the opinion that the Interim Rules should be revised to establish a methodology whereby the provider will be allowed to choose between several options for its method of accounting for common area usage (with a default method, if none is chosen). Such revisions are reflected in Rule R18-8, which is included in Appendix A, attached hereto, at pages 4-6.

The Commission finds that the legislation may be implemented by the establishment of new Rule R18-8. After initiating a rulemaking proceeding, issuing Interim Rules (Rule R18-8), receiving comments from interested parties, and allowing the interested parties an ample time to experience the interim rules, the Commission finds that the attached rules should be adopted.

IT IS, THEREFORE, ORDERED as follows:

1. That the revision to Rule R18-6 and the establishment of Rule R18-8 (attached as Appendix A), are hereby promulgated and supersede the existing Interim Rules.

2. 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, and the Attorney General.

ISSUED BY ORDER OF THE COMMISSION.
This the <u>10th</u> day of <u>January</u>, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

rb011012.01

APPENDIX A

Chapter 18.

Provision of Water and Sewer Service by Landlords.

Rule R18-1. Application.

This Chapter governs charging for the costs of providing water or sewer utility service as authorized by G.S. 62-110(g).

Rule R18-2. Definitions.

(a) *Same contiguous 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.

(b) *Provider.* The landlord purchasing water or sewer utility service from a supplier and charging for the costs of providing the service or services to tenants. The provider shall be the owner of the premises served.

(c) *Supplier.* A public utility or an agency or organization exempted from regulation from which a provider purchases water or sewer service.

(d) *Tenant.* The lessee of property from the landlord, to whom the water or sewer service purchased by the provider from the supplier is provided.

(e) *Apartment complex.* Premises where one or more buildings under common ownership comprising fifteen (15) or more apartments are available for rental to tenants.

(f) *Manufactured home park.* Premises where a combination of fifteen (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 tenants.

(g) *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 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, (d) the schedule of rates the applicant proposes to charge the applicant's customers, (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. The Commission shall approve or disapprove an application within 30 days of the filing of a completed application with the Commission. 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 customer may examine the records pertaining to the customer'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 (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. 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 tenant may request approval of an administrative fee greater than $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 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 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 R18-8).

(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, (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 administrative fee in excess of $3.75 shall include (1) the provider's cost of meter reading, billing, and collection, (2) the current or proposed base charge from the supplier, (3) the number of tenants to whom water or sewer service is provided, and (4) the proposed administrative fee. 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) 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 tenant or which has been reported to the provider.

(f) 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:

(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 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) 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 27699-4326.

(g) Each provider shall adopt some means of informing its 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.

Pursuant to G.S. 62-110(g)(1a), if the contiguous premises were built prior to 1989, and the provider determines that, due to the plumbing configuration of the building, measurement of the tenant's total water usage is impractical or is not economical, the provider may estimate each tenant's total water usage based upon the hot water usage of each tenant as a percentage of all of the tenants' hot water usage.

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.

The provider shall not include in a 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 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 a.):

a. The provider shall reduce the total water amount of water purchased by 20%.

b. 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 tenants' bills.

c. 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 tenants' bills.

d. 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 tenants' bills.

The provider shall furnish a water/sewer utility bill to the 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 (a-d)).
3. Total amount of hot water measured for all tenants.
4. Amount of hot water measured for the individual tenant.
5. Amount of water the individual 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.
9. A local or toll-free telephone number and address that the tenant can use to obtain more information about the bill.

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.

DOCKET NO. E-2, SUB 998
DOCKET NO. E-7, SUB 986

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Corporation And Progress Energy, Inc., to Engage in a Business Combination Transaction and to Address Regulatory Conditions and Codes of Conduct	)	ORDER APPROVING MERGER SUBJECT TO REGULATORY CONDITIONS AND CODE OF CONDUCT

HEARD: On Tuesday, September 20, 2011, at 9:00 a.m., Wednesday, September 21, 2011, at 9:30 a.m., Thursday, September 22, 2011, at 9:30 a.m., and Monday, June 25, 2012, at 2:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; Commissioners Lorinzo L. Joyner, William T. Culpepper, III, Bryan E. Beatty, Susan W. Rabon, ToNola D. Brown-Bland, and Lucy T. Allen[1]

APPEARANCES:

For Progress Energy, Inc., and Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.:

Len S. Anthony and Kendal C. Bowman, Post Office Box 1551 PEB 17A, Raleigh, North Carolina 27601

For Duke Energy Corporation and Duke Energy Carolinas, LLC:

Kodwo Ghartey-Tagoe, 550 South Tryon Street, Charlotte, North Carolina 28202

Kendrick C. Fentress, 3700 Glenwood Avenue, Suite 330, Raleigh, North Carolina 27612

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 3700 Glenwood Avenue, Suite 330, Raleigh North Carolina 27612

For Blue Ridge Paper Products:

Christopher J. Ayers, Poyner Spruill LLP, Post Office Box 1801, Raleigh, North Carolina 27602

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[1] Commissioner Lorinzo L. Joyner retired on December 31, 2011, and, therefore, did not participate in this Order.

For Carolina Industrial Group for Fair Utility Rates II and Carolina Industrial Group for Fair Utility Rates III:

Ralph McDonald and Carson Carmichael, Bailey & Dixon, LLP, Post Office Box 1351, Raleigh, North Carolina 27601

For Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp, Page & Currin, LLP, 4010 Barrett Drive, Suite 210, Raleigh, North Carolina 27609

For the Commercial Group:

Robert Paschal, Young Moore, Post Office Box 31627, Raleigh, North Carolina 27622

Alan R. Jenkins, Jenkins at Law, LLC, 2265 Roswell Road, Marietta, Georgia 30062

For ElectriCities of North Carolina, Inc., North Carolina Eastern Municipal Power Agency, and North Carolina Municipal Power Agency No. 1:

Daniel C. Higgins, Burns, Day & Presnell, PA, Post Office Box 10857, Raleigh, North Carolina 27605

For Environmental Defense Fund, Sierra Club, Southern Alliance for Clean Energy, and South Carolina Coastal Conservation League:

Gudrun Thompson and John Suttles, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

Jill Tauber, Southern Environmental Law Center, 122 C Street, N.W., Suite 390, Washington, District of Columbia 20001

For International Brotherhood of Electrical Workers:

Jonathan D. Newman, Sherman, Dunn, Cohen, Leifer & Yellig, P.C., 900 Seventh Street, N.W., Suite 1000, Washington, District of Columbia 20001

For North Carolina Electric Membership Corporation:

Richard M. Feathers, North Carolina Electric Membership Corporation, Post Office Box 27306, Raleigh, North Carolina 27611

For North Carolina Sustainable Energy Association:

Kurt Olson and Michael D. Youth, North Carolina Sustainable Energy Association, 1111 Haynes Street, Suite 109, Raleigh, North Carolina 27608

For North Carolina Waste Awareness and Reduction Network:

John D. Runkle, Attorney at Law, Post Office Box 3793, Chapel Hill, North Carolina 27515

For City of Orangeburg, South Carolina:

James N. Horwood, Spiegel & McDiarmid, LLP, 1333 New Hampshire Avenue, N.W., Washington, District of Columbia 20036

For Piedmont Electric Membership Corporation, Rutherford Electric Membership Corporation, Blue Ridge Electric Membership Corporation, and Haywood Electric Membership Corporation:

Gray Styers and Charlotte Mitchell, Styers and Kemerait, 1101 Haynes Street, Suite 101, Raleigh, North Carolina 27604

For Public Works Commission of the City of Fayetteville, North Carolina:

James West, West Law Offices, P.C., 434 Fayetteville Street, Suite 2325, Raleigh, North Carolina 27601

For South Carolina Office of Regulatory Staff:

J. Carr McLamb, Jr., Jordan Price, 1951 Clark Avenue, Raleigh, North Carolina 27605

Nanette Edwards, South Carolina Office of Regulatory Staff, 1401 Main Street, Suite 900, Columbia, South Carolina 29201

For the Using and Consuming Public:

Antoinette R. Wike and Gisele L. Rankin, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On April 4, 2011, Duke Energy Corporation (Duke) and Progress Energy, Inc. (Progress) (collectively, the Applicants), filed an application in the above-captioned dockets seeking Commission approval pursuant to G.S. 62-111(a) to engage in a business combination transaction (merger), to revise and apply Duke Energy Carolinas, LLC's (DEC) Regulatory Conditions and Code of Conduct to Progress and Progress Energy Carolinas, Inc. (PEC), and to nullify PEC's Regulatory Conditions and Code of Conduct.

The application included the following exhibits: Exhibit 1 – a copy of the Agreement and Plan of Merger between Duke Energy Corporation and Progress Energy, Inc., dated January 8, 2011 (Merger Agreement); Exhibit 2 – investment analyses of the proposed transaction by Oppenheimer, Baird, and Bank of America/Merrill Lynch; Exhibit 3 - a proposed Joint Dispatch Agreement between Duke Energy Carolinas, LLC and Progress Energy Carolinas, Inc.; Exhibit 4 – an Analysis of Economic Efficiencies under Joint Dispatch Prepared for Duke Energy Carolinas and Progress Energy Carolinas by Compass Lexecon (Compass Lexecon Study); Exhibit 5 – Fuel Synergies Review prepared by Booz & Company (Fuel Synergies Review, which was filed under seal); Exhibit 6 – Regulatory Conditions approved by the Commission in its Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, issued March 24, 2006, in Docket No. E-7, Sub 795 (Sub 795 Order), revised to reflect the affiliation of Progress and PEC with Duke; and Exhibit 7 – a Market Power Study consisting of Exhibits J-3 through J-11 to the testimony of William H. Hieronymous filed with the Federal Energy Regulatory Commission (FERC) by the Applicants in support of their merger approval application (Market Power Study).

The Commission's Order Requiring Filing of Analyses, issued November 2, 2000, in Docket No. M-100, Sub 129 (Sub 129 Order), requires that merger applications be accompanied by a market power analysis and a cost-benefit analysis. The Applicants asserted that the Market Power Study, the derivation of joint dispatch fuel savings in the Compass Lexecon Study and the additional fuel savings set forth in the Fuel Synergies Review complied with this requirement.

The Applicants noted that the issuance of common stock by Duke to acquire the outstanding stock of Progress is governed by Regulatory Condition Nos. 41 and 54 approved by the Commission in the Sub 795 Order. Regulatory Condition No. 41(d) provides that "All securities issuances or financings that are associated with a merger, acquisition, or other business combination shall be filed in conjunction with the information requirements and deadlines stated in Regulatory Condition No. 54." Subsection (a) of Regulatory Condition No. 54 provides that "For any proposed merger, acquisition, or other business combination by or affecting [DEC], [DEC] shall file an application for approval pursuant to G.S. 62-111(a) at least 180 days before the proposed closing date for merger, acquisition, or business combination." As DEC will issue no securities in connection with the merger, Duke and DEC requested acknowledgement by the Commission that Regulatory Condition No. 54 had been satisfied by the filing of the application.

The application was preceded by advance notices filed on February 4, 2011, by DEC and PEC in Docket Nos. E-7, Sub 980, and E-2, Sub 995, respectively. In Docket No. E-7, Sub 980, DEC provided advance notice pursuant to Regulatory Condition Nos. 3, 9, 10, and 59(b), as approved in the Sub 795 Order, of its intent to transfer independent operational control of its generation facilities to combined operational control pursuant to a proposed Joint Dispatch Agreement (JDA) with PEC and to request that the FERC approve a Joint Open Access Transmission Tariff (Joint OATT) covering the balancing authority areas (BAA) of both DEC and PEC. DEC noted in its advance notice that the Commission may extend the advance notice period pursuant to Regulatory Condition No. 59(b) and may review and consider the proposed JDA as part of the merger proceeding. In Docket No. E-2, Sub 995, PEC provided advance notice pursuant to Regulatory Condition Nos. 33, 38, and 45, as approved in the Commission's Order Adopting Revised Regulatory Conditions and Code of Conduct, issued October 27, 2004, in Docket No. E-2, Sub 844 (Sub 844 Order), of its intention to transfer operational control of its generation assets to DEC. By Order issued April 4, 2011, the Commission gave Duke and Progress approval to file with the FERC the proposed JDA and the conformed Merger Agreement premised upon the JDA.

On April 4, 2011, in Docket No. EC11-60-000, Duke and Progress, together with their public utility subsidiaries DEC and PEC, submitted to the FERC their application for approval of the merger under Sections 203(a)(1) and 203(a)(2) of the Federal Power Act (FPA). Concurrently with this application, Duke on its own behalf and on behalf of DEC, and Progress on its own behalf and on behalf of PEC, filed with the FERC a pro forma JDA in Docket No. ER11-3306-000 and a pro forma Joint OATT in Docket No. ER11-3307-000.

On April 27, 2011, the Commission issued an Order scheduling the merger application for hearing, establishing deadlines for petitions to intervene and the filing of testimony, establishing discovery guidelines, requiring public notice, and incorporating by reference into the merger dockets the record in the advance notice dockets, which the Commission then closed by separate Order. In addition, the Commission found and concluded that the application satisfied the requirements of the Sub 129 Order, Regulatory Condition No. 33 of the Sub 844 Order, and Regulatory Condition No. 54 of the Sub 795 Order.

On May 20, 2011, the Applicants prefiled the direct testimony of the following witnesses: James E. Rogers and William D. Johnson; Lynn J. Good; Alexander (Sasha) J. Weintraub; and Joseph P. Kalt.

On June 22, 2011, DEC and PEC filed a revised proposed JDA, containing minor revisions, and advance notice of their intent to make these revisions and file the proposed revised JDA with the FERC. By Order issued July 11, 2011, the Commission gave DEC and PEC approval to proceed with filing the revised JDA with the FERC.

Petitions to intervene in this proceeding were filed by Environmental Defense Fund (EDF), the Sierra Club, the South Carolina Coastal Conservation League, and Southern Alliance for Clean Energy (collectively, EDF, et al.); International Brotherhood of Electrical Workers (IBEW); North Carolina Sustainable Energy Association (NCSEA); the City of Orangeburg, South Carolina; the Commercial Group; Blue Ridge Paper Products, Inc., d/b/a Evergreen Packaging (Blue Ridge); North Carolina Waste Awareness and Reduction Network (NC WARN); Carolina Industrial Group for Fair Utility Rates II and Carolina Industrial Group for Fair Utility Rates III; Carolina Utility Customers Association, Inc.; the South Carolina Office of Regulatory Staff; North Carolina Farm Bureau Federation; Duke Wholesale Customer Group; EnergyUnited Electric Membership Corporation; ElectriCities of North Carolina, Inc. (ElectriCities), North Carolina Municipal Power Agency 1 (NCMPA1), and North Carolina Eastern Municipal Power Agency (NCEMPA); Blue Ridge Electric Membership Corporation, Haywood Electric Membership Corporation, Piedmont Electric Membership Corporation, and Rutherford Electric Membership Corporation; North Carolina Electric Membership Corporation (NCEMC); the Public Works Commission of the City of Fayetteville, North Carolina (Fayetteville); the Greenwood Commissioners of the Public Works of the City of Greenwood, South Carolina; the City of Concord, North Carolina; the City of Kings Mountain, North Carolina; the Town of Due West, South Carolina; the Town of Prosperity, North Carolina; the

Town of Forest City, North Carolina; the Town of Highlands, North Carolina; the Town of Dallas, North Carolina; Lockhart Power Company; and Western Carolina University. By various orders, the Commission granted the petitions to intervene. The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

Petitions to intervene out of time were filed by the North Carolina Justice Center, the North Carolina Housing Coalition, Public Citizen, Greenpeace USA, the Nuclear Information and Resource Center, the Florida Consumer Action Network, Plains and Eastern Clean Line, LLC, and the City of New Bern, North Carolina. All of these petitions were denied.

Limited admissions to practice before the Commission were granted to a number of out-of-state attorneys.

On August 25, 2011, the Public Staff filed a motion for an extension of time to file testimony and a revision to the procedural schedule. On August 26, 2011, the Commission issued an Order granting the motion and extending the time for the Public Staff, DEC, and PEC to file their settlement agreement until September 1, 2011; extending the time for intervenors to file testimony until September 7, 2011; extending the time for the Applicants to file rebuttal testimony until September 14, 2011; and providing for the filing of a response by the Public Staff to the testimony of other intervenors by September 14, 2011.

On August 26, 2011, NCEMC filed a letter stating that it no longer opposed the approvals sought by the Applicants.

On September 2, 2011, having been granted an oral one-day extension of time, the Public Staff filed an Agreement and Stipulation of Settlement between the Applicants, DEC, PEC, and the Public Staff (Stipulation). Attached to the Stipulation were proposed Regulatory Conditions and a Code of Conduct. Also on September 2, 2011, the Public Staff filed the testimony of Mathew J. Morey and James G. Hoard.

On September 6, 2011, EDF, et al., filed a motion to extend the time for filing intervenor testimony and statements of position until September 8, 2011, and to extend the time for filing the Applicants' rebuttal testimony and the Public Staff's responsive filing until September 15, 2011. By Order issued September 7, 2011, the Commission granted this motion.

On September 8, 2011, EDF, et al., filed the testimony of Richard S. Hahn; Blue Ridge filed the testimony of Michael Ferguson; the City of Orangeburg filed a statement of position and the testimony of John Bagwell; the Commercial Group filed the testimony of Steve W. Chriss; NCSEA filed the testimony of Ivan Urlaub; and NC WARN filed a statement of position and the testimony of Roger D. Colton. Also on September 8, 2011, the South Carolina Office of Regulatory Staff filed a notice of settlement agreement.

On September 9, 2011, IBEW filed a statement of position, dated September 7, 2011, and a motion for leave to file out of time. By Order issued September 9, 2011, the Commission granted IBEW's motion.

On September 12, 2011, the Applicants filed motions to strike all or portions of the testimony of Blue Ridge and NCSEA. On September 13, 2011, and September 14, 2011, NCSEA and Blue Ridge, respectively, filed responses to the motions to strike.

On September 14, 2011, the Applicants filed a motion to strike portions of the testimony of EDF, et al. On September 16, 2011, EDF, et al., filed their response to the motion.

On September 14, 2011, the Applicants filed a motion to strike the testimony of the City of Orangeburg. On September 16, 2011, the City of Orangeburg filed its response to the motion.

On September 15, 2011, the Public Staff filed its response to the statements of position and prefiled testimony of the other intervenors. Included in the filing were clean corrected and redlined versions of the proposed Regulatory Conditions and Code of Conduct filed on September 2, 2011. Two substantive changes were included in the corrected version: a revision to the definition of fully distributed cost and the addition of the Town of Winterville to the list of historically served wholesale customers in Regulatory Condition No. 3.7(b). Also included in this filing were a redlined version of the Regulatory Conditions and Code of Conduct approved by the Commission in the Sub 795 Order showing the changes made by the proposed Regulatory Conditions and Code of Conduct and a redlined version of the Regulatory Conditions and Code of Conduct attached as Exhibit 6 to the merger application.

Also on September 15, 2011, the Applicants filed the rebuttal testimony of Paula J. Sims, B. Mitchell Williams, Craig DeBrew, Alexander J. Weintraub, Lynn J. Good, Joseph P. Kalt, and John L. Harris.

On September 19, 2011, the Commission issued an Order denying the Applicants' motions to strike the testimony of the City of Orangeburg, NCSEA, Blue Ridge, and EDF, et al., except for a limited portion of the testimony of EDF, et al.

By Order issued September 19, 2011, the Commission admitted into evidence the application and Exhibits 1, 2, 4, 5 (under seal), and 7 filed on April 4, 2011; the revised JDA filed on June 22, 2011; and the corrected Regulatory Conditions and Code of Conduct filed on September 2, 2011.

Also on September 19, 2011, the Public Staff filed a proposed revision to Regulatory Condition No. 4.4 pursuant to a request by Fayetteville and requested that the Regulatory Conditions that were to be admitted into evidence be revised accordingly. This revision was allowed by Chairman Finley in open hearing on September 20, 2011.

Numerous statements of position from members of the public were received by the Commission and the Public Staff and were filed in these dockets.

The matter came on for hearing as scheduled, beginning on September 20, 2011. The following persons testified as public witnesses: Dr. Freda Porter, Thyron Williams, Robert Eidus, Jon Hudson, Dan Conrad, Harry Phillips, Rebekah O'Connell, Albert Ripley, Olga Grlic, Beth Henry, Dr. Thomas Henkel, Jerry Markatos, Chris Estes, Miriam Thompson, Deborah Arnesen, Robert Rodriquez, Alice Loyd, Rev. Melvin Whitley, DeWayne Barton, Bobi Gallagher, Joan Novak, Sherri Zann Rosenthal, Ryan Thomson, Wells Eddleman, Susannah Tuttle, Jim Senter, Rev. Lynice Williams, Elizabeth Hutchby, and Audrey Schwankl.

The Applicants presented the testimony of William D. Johnson, Chairman, President, and Chief Executive Officer of Progress; James E. Rogers, Chairman, President, and Chief Executive Officer of Duke; Lynn J. Good, Chief Financial Officer of Duke and the proposed Chief Financial Officer of the combined companies upon closing; Alexander (Sasha) J. Weintraub, Vice President – Fuels and Power Optimization for PEC; and Joseph P. Kalt, Ford Foundation Professor of International Political Economy at the John F. Kennedy School of Government, Harvard University, and a senior economist at Compass Lexecon.

The Public Staff presented the testimony of James G. Hoard, Assistant Director, Public Staff Accounting Division; and Matthew J. Morey, Senior Consultant with Christensen Associates Energy Consulting, LLC.

EDF, et al., presented the testimony of Richard S. Kahn, a Principal Consultant with La Capra Associates, Inc.

The City of Orangeburg presented the testimony of John Bagwell, Director of the Electric Division of the Department of Public Utilities.

The Commercial Group presented the testimony of Steve W. Chriss, Senior Manager, Energy Regulatory Analysis, for Wal-Mart Stores, Inc.

NCSEA presented the testimony of Ivan Urlaub, Executive Director.

NC WARN presented the testimony of Roger D. Colton, a principal in the firm of Fisher, Sheehan and Colton, Public Finance and General Economics.

The Applicants presented the rebuttal testimony of Sasha Weintraub, Lynn J. Good; Joseph P. Kalt; Paula J. Sims, Chief Integration Officer for the Merger and Senior Vice President of Corporate Development and Improvement for Progress; B. Mitchell Williams, Manager, Regulatory Affairs, for PEC; and John L. Harris, Principal Financial Specialist in the Treasury and Enterprise Risk Management Department of Progress Energy Service Company, LLC (PESC).

On September 22, 2011, Blue Ridge filed a Settlement Agreement entered into by Duke, Progress, DEC, PEC, and Blue Ridge resolving the issues among them in these dockets. The testimony of Michael Ferguson on behalf of Blue Ridge and the rebuttal testimony of Craig DeBrew on behalf of PEC were withdrawn pursuant to this stipulated agreement.

On September 30, 2011, the FERC issued its Order on Disposition of Jurisdictional Facilities and Merger in Docket No. EC11-60-000 (FERC Merger Order). In this order, the FERC conditionally approved the proposed merger subject to approval of market power mitigation measures to be proposed by the Applicants in a compliance filing to be made within

60 days of the issuance of the FERC Merger Order to remedy the market power analysis screen failures identified by the FERC. The FERC stated that such measures could include, but need not be limited to, joining or forming a regional transmission organization (RTO), implementation of an independent coordinator of transmission (ICT) arrangement, generation divestiture, virtual divestiture of generation, and/or proposals to build new transmission to provide greater access to third-party suppliers. The purpose of these measures would be to mitigate the wholesale market power effects that the FERC concluded the merger would have on horizontal competition in the DEC BAA and the PEC East BAA. The FERC stated that regardless of what mitigation measure or measures were proposed, the mitigation efforts would have to be sufficient to reduce the Herfindahl-Hirschman Index (HHI) changes resulting from the merger to no more than a 50 point increase for highly concentrated markets and no more than a 100 point increase for moderately concentrated markets.

On October 7, 2011, DEC filed with the Commission a motion and advance notice in Docket No. E-7, Sub 995, requesting a waiver of the 30-day advance notice required prior to a filing with the FERC by Regulatory Condition No. 10 approved in the Sub 795 Order. In the alternative, DEC requested that the Commission shorten the advance notice period to seven days. DEC asserted that a waiver or shortening of the advance notice period would enable the Applicants to proceed to file the proposed market power mitigation plan in response to the FERC Merger Order.

On October 17, 2011, the Commission issued an Order granting the motion for waiver and requiring Duke to file a copy of the FERC mitigation plan in these dockest contemporaneously with the filing of the plan with the FERC. The Order stated that it did not constitute a decision by the Commission as to the merits of the proposed mitigation plan and was without prejudice to the right of any party to these dockets to contest relevant issues due to the filing of the mitigation plan with the FERC. The Order further stated that the Commission and the parties would have the opportunity to review the proposed mitigation plan prior to the issuance of an order by the Commission on the Applicants' merger application.

On October 17, 2011, Duke and Progress filed their proposed mitigation plan with the FERC in Docket No. EC11-60-000. Contemporaneously therewith, Duke on its own behalf and on behalf of DEC, and Progress on its own behalf and on behalf of PEC, filed the same documents with the Commission in the present dockets.

On October 19, 2011, Duke filed on behalf of itself and DEC, with the FERC in Docket No. ER12-115-000, an executed, eTariff-compliant JDA to become effective upon consummation of the merger. On the same date, Progress filed on its own behalf and on behalf of PEC, in Docket No. ER12-118-000, its concurrence to the executed JDA. On October 20, 2011, Duke on behalf of itself and DEC, and Progress on behalf of itself and PEC, filed a motion requesting the FERC to consolidate the joint dispatch dockets and give expedited consideration to their request for approval.

Also on October 19, 2011, Duke on behalf of itself and DEC, and Progress on behalf of itself and PEC, filed an eTariff-compliant Joint OATT with the FERC in Docket Nos. ER12-116-000, ER12-119-000 and ER11-3307-000. On October 20, 2011, Duke on behalf of itself and

DEC, and Progress on behalf of itself and PEC, filed a motion requesting the FERC to consolidate the Joint OATT dockets and give expedited consideration to their request for approval.

Pursuant to the Notice of Mailing of Transcript issued by the Commission on October 12, 2011, briefs and proposed orders were due to be filed by November 14, 2011.

On November 2, 2011, the Commission issued a Post-Hearing Order Requiring Verified Information (Post-Hearing Order) requiring the Applicants to answer jointly a list of 25 questions and to submit their answers under oath in the form of a verified affidavit or affidavits on or before November 17, 2011.

On November 7, 2011, EDF, et al., filed a motion requesting the Commission to (a) suspend the proceedings in this case until the FERC merger proceeding is resolved and the intervenors and the Commission have the opportunity to evaluate and comment on the Applicants' responses to the Post-Hearing Order, or (b) hold the proceedings open to allow the parties to file comments on the FERC's final orders in the merger and related dockets, and extend the deadline for filing briefs and proposed orders to December 1, 2011.

On November 8, 2011, the Commission issued an Order extending the deadline for filing briefs and proposed orders until November 23, 2011.

On November 17, 2011, the Applicants filed their verified responses to the questions propounded by the Commission in its November 2, 2011 Post-Hearing Order.

On December 14, 2011, the FERC issued an Order Rejecting Compliance Filing in which it found the Applicants' proposed market power mitigation plan was inadequate to address the wholesale market power concerns raised in the FERC Merger Order. On that same date, the FERC also issued orders dismissing the Applicants' applications for approval of the JDA and Joint OATT. However, all three FERC orders were without prejudice to the Applicants' right to file revised proposals.

On February 22, 2012, in Docket No. E-7, Sub 995, the Applicants filed an Advance Notice of their intent to file a revised market power mitigation plan with the FERC. On March 8, 2012, the Public Staff filed its Response to the Applicants' Advance Notice. The Public Staff stated that it had no objection to the Applicants filing the revised mitigation plan with the FERC because that filing would not affect the Commission's jurisdiction to decide the merits of the proposed merger or the parties' opportunity to be heard on the effects of the plan. No other party filed a response to the Applicants' Advance Notice.

On March 26, 2012, the Applicants filed with the FERC a revised mitigation plan in Docket No. EC11-60-004. On the same date, the Applicants filed with the FERC the Joint Dispatch Agreement in Docket Nos. ER12-1338-000, ER12-1347-000, and ER11-3306-000, and Joint Open Access Transmission Tariff (Joint OATT), in Docket Nos. ER12-1343-000, ER12-1345-000, ER11-1346-000 and ER11-3307-000.

On May 8, 2012, the Public Staff and the Applicants filed a Supplemental Agreement and Stipulation of Settlement (Supplemental Stipulation) that made several changes to the original Stipulation. On the same date, the Public Staff filed a Motion for Establishment of Procedural Schedule proposing that the Public Staff and the Applicants file testimony on or about May 15, 2012, supporting and explaining the Supplemental Stipulation, and that the Commission establish dates for intervenors to file comments or testimony on the Supplemental Stipulation and the Public Staff and the Applicants to file reply comments or rebuttal testimony.

On May 15, 2012, the Commission issued an Order allowing the Public Staff and the Applicants to file testimony supporting and explaining the Supplemental Stipulation filed on May 8, 2012. Although the Commission concluded there was not good cause at that time to establish due dates for intervenors to file comments or testimony and for the Public Staff and the Applicants to file reply comments or rebuttal testimony, the Order encouraged the intevenors to conduct relevant and appropriate discovery on the Supplemental Stipulation and supporting testimony filed by the Public Staff and the Applicants to prepare as much as reasonably possible to be in position to file comments or testimony regarding the Supplemental Stipulation. The Order further stated that in the event the FERC issued a decision on or about June 8, 2012, that did not make a material change to the terms of the Stipulation or Supplemental Stipulation, the Commission intended to issue a procedural order that would expedite the filing of comments and reply comments on the Supplemental Stipulation.

On May 15, 2012, the Applicants filed the supplemental testimony of Alexander J. Weintraub explaining the Applicants' revised market power mitigation plan and Supplemental Stipulation. On the same date, the Public Staff filed the supplemental testimony of James G. Hoard discussing the impact of the Applicants' revised market power mitigation plan on the Stipulation and explaining the Supplemental Stipulation.

On June 8, 2012, the FERC issued an Order Accepting Revised Compliance Filing, As Modified, And Power Sales Agreements (FERC Market Power Order), in Docket Nos. EC11-60-004, ER12-1339-000, ER12-1340-000, ER12-1341-000 and ER12-1342-000. In summary, the FERC Market Power Order accepted the Applicants' revised mitigation plan, subject to several conditions. In addition, the FERC issued an Order on Joint Dispatch Agreement and Joint Open Access Transmission Tariff (FERC JDA Order) in Docket Nos. ER12-1338-000, ER12-1343000, ER12-1345-000, ER12-1346-000 and ER12-3347-000. In summary, the FERC JDA Order approved the JDA, subject to certain modifications.

On June 11, 2012, the Commission issued an Order Establishing Procedural Schedule directing that the Applicants and Public Staff file comments or testimony regarding the impact of the FERC Market Power and JDA Orders on this proceeding and the Supplemental Stipulation by June 13, 2012, that intervenors file comments or testimony regarding the FERC Market Power and JDA Orders and the comments or testimony filed by the Applicants and the Public Staff by June 18, 2012, and that the Applicants and Public Staff file reply comments or rebuttal testimony by June 19, 2012.

On June 12, 2012, DEC and PEC filed a Motion to Waive the Advance Notice Period Pursuant to Regulatory Condition Nos. 9 and 10, along with a revised version of the JDA, requesting that the Commission waive the 30-day advance notice requirement applicable to the filing of the revised JDA with the FERC.

On June 13, 2012, the Applicants filed the further supplemental testimony of Alexander J. Weintraub addressing the impact of the FERC Market Power and JDA Orders on this proceeding and the Supplemental Stipulation. On the same date, the Public Staff filed comments regarding the same subjects.

On June 15, 2012, the Commission issued an Order Regarding Advance Notice granting the request of DEC and PEC for a waiver of the 30-day advance notice requirement applicable to the filing of the revised JDA with the FERC.

On June 18, 2012, comments were filed by the NCSEA, City of Orangeburg, and EDF, et al.

In addition, on June 18, 2012, NC WARN filed an unverified document entitled Position of NC WARN (Position Statement). In its Position Statement, NC WARN identified a number of alleged new issues in addition to those issues identified in the Commission's June 11, 2012 Order. NC WARN stated that it was unable to waive cross-examination of Duke's witnesses and, therefore, it requested a hearing to conduct such cross-examination. Further, NC WARN requested that the Commission allow it to present testimony and evidence, and that the Commission receive additional testimony from public witnesses. Finally, NC WARN stated that it intended to make a motion to request that the Commission order public disclosure of certain information previously filed with the Commission as proprietary and confidential.

On June 19, 2012, the Applicants and the Public Staff filed reply comments. With regard to NC WARN's Position Statement, the Applicants stated, among other things, that the alleged additional issues identified by NC WARN were speculative and were not issues appropriate or necessary to address in the merger proceeding. Further, the Applicants asserted that to the extent these issues materialize in the future they will be addressed by the Commission in other dockets. The Applicants stated therefore, these alleged new issues do not require a further hearing by the Commission in its consideration of their merger application.

Also on June 19, 2012, the Public Staff filed comments stating, among other things, that NC WARN's contentions were not relevant to the issues presented in this proceeding or had already been addressed in prior hearings and, therefore, did not require a further hearing by the Commission.

On June 19, 2012, the Commission issued an Order Scheduling Hearing. The Order scheduled a hearing on Monday, June 25, 2012, at 2:00 p.m., to allow an opportunity for the introduction of the supplemental testimony of the Applicants' and the Public Staff's witnesses and to allow NC WARN to cross-examine the Applicants' and the Public Staff's witnesses regarding their supplemental testimony. Further, the Order rejected NC WARN's request to present testimony and to allow additional public witnesses to testify. In addition, the Order stated that to the extent that NC WARN desired to make motions for further actions by the

Commission, as alluded to in its Position Statement, NC WARN should do so in writing in compliance with the Commission's rules.

On June 21, 2012, NC WARN filed a Motion for Reconsideration pursuant to G.S. 62-80 requesting that the Commission modify its Order Scheduling Hearing to allow NC WARN to more broadly cross-examine the Applicants' and the Public Staff's witnesses.

Also on June 21, 2012, NC WARN filed a Motion to Make Settlement Documents Public.

On June 22, 2012, the Applicants filed a Response and Motion to Deny NC WARN's Motion for Reconsideration and a Response and Motion to Deny NC WARN's Motion to Make Settlement Documents Public.

On June 22, 2012, the Commission issued an Order denying NC WARN's Motion for Reconsideration

On June 25, 2012, the Commission held the hearing as scheduled in its June 19, 2012 Order Scheduling Hearing. The Applicants introduced the supplemental testimony and further supplemental testimony of Alexander J. Weintraub. The Public Staff introduced the supplemental testimony and exhibits of James G. Hoard and the Supplemental Stipulation, as amended. In addition, NC WARN cross-examined Applicants witness Weintraub and Public Staff witness Hoard regarding their supplemental testimony. At the conclusion of the hearing, NC WARN and the Applicants made oral arguments. The Commission informed the parties that they could file post-hearing briefs and/or proposed orders, but that such filings would not be considered by the Commission unless received prior to the issuance of the Commission's decision. Finally, NC WARN was granted leave to file an offer of proof.

On June 25, 2012, the Applicants provided a notice of acceptance letter to the_FERC, including copies of the binding construction agreements with American Electric Power and Dominion Virginia Power that the FERC’s Market Power Order required the Applicants to file within 15 days (FERC Acceptance Letter), in which they accepted the FERC’s revisions to their market power mitigation proposal, as required by the FERC’s Market Power Order.

On June 26, 2012, the Commission issued an Order Allowing Responses to Public Records Request, allowing parties to the settlement agreements filed under seal to respond to NC WARN's request that those agreements be made public.

On June 27, 2012, NC WARN filed an Offer of Proof.

On June 28, 2012, the Applicants filed a Motion to Reject NC WARN’s Offer of Proof.

On June 28, 2012, responses to NC WARN’s Motion to Make Settlement Documents Public were filed by NCEMC, NCMPA1, NCEMPA, Blue Ridge Electric Membership Corporation, Haywood Electric Membership Corporation, Piedmont Electric Membership Corporation, Rutherford Electric Membership Corporation, and jointly by the Applicants, Carolina Industrial Group for Fair Utility Rates II and III and Carolina Utility Customers Association, Inc.

To the extent allowed by G.S. 62-65(b), the Commission takes judicial notice of the records in the above FERC dockets, the FERC Acceptance Letter, as well as FERC Docket Nos. EC11-60-000 (merger application), ER12-118-000 (eTariff-compliant JDA), ER11-3307-000 (pro forma Joint OATT), and ER11-3307-000, ER12-116-000 and ER12-119-000 (eTariff compliant Joint OATT).

Based on the foregoing, the evidence presented at the hearings, and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. Duke is a corporation duly organized and existing under the laws of Delaware and headquartered in Charlotte, North Carolina. DEC, a wholly-owned subsidiary of Duke, is a limited liability company organized, existing, and operating under the laws of North Carolina.

2. DEC is engaged in the business of generating, transmitting, distributing, and selling electricity to approximately 2.4 million retail customers in a service area that covers more than 24,000 square miles in portions of central and western North Carolina and western South Carolina. DEC also sells electricity at wholesale to municipal, cooperative, and investor-owned electric utilities.

3. DEC also is a public utility subject to the jurisdiction of this Commission and the jurisdiction of the Public Service Commission of South Carolina and a public utility under the FPA and is subject to the jurisdiction of the FERC.

4. Duke Energy Indiana, Inc. (Duke Indiana), Duke Energy Kentucky, Inc. (Duke Kentucky), and Duke Energy Ohio, Inc. (Duke Ohio; collectively, the former Cinergy utilities), are wholly owned subsidiaries of Duke that provide retail electric service in other states.

5. Progress is a corporation duly organized and existing under the laws of North Carolina and headquartered in Raleigh, North Carolina. PEC, a wholly-owned subsidiary of Progress, is a corporation organized, existing, and operating under the laws of North Carolina.

6. PEC is engaged in the business of generating, transmitting, distributing, and selling electricity to approximately 1.5 million retail customers in a service area that covers more than 34,000 square miles in portions of eastern, central, and western North Carolina and eastern South Carolina. PEC also sells electricity at wholesale to municipal, cooperative, and investor-owned electric utilities.

7. PEC also is a public utility subject to the jurisdiction of this Commission and the jurisdiction of the Public Service Commission of South Carolina and a public utility under the FPA and is subject to the jurisdiction of the FERC.

8. Florida Progress Corporation, d/b/a Progress Energy Florida (PEF), a wholly-owned subsidiary of Progress, provides retail electric service in Florida.

9. The Applicants are lawfully before the Commission pursuant to G.S. 62-111(a) with respect to the relief sought in the application and are in compliance with the filing requirements established in the Sub 129 Order with respect to the market power and cost-benefit analyses submitted with the application.

10. The Merger Agreement provides that Progress shareholders will receive 2.6125 shares of Duke common stock for each share of Progress common stock they own upon the closing of the transaction. This exchange ratio will be adjusted to 0.87083 shares of Duke common stock for each Progress share to account for a one-for-three reverse stock split to be effected by Duke in connection with the transaction.

11. After the close of the merger, Duke shareholders will own approximately 63 percent, and former Progress shareholders will own approximately 37 percent, of the post-merger Duke holding company stock. The Board of Directors will consist of 18 directors, 11 designated by Duke and seven designated by Progress.

12. The merger will occur at the holding company level, with Progress becoming a subsidiary of Duke and DEC, PEC, PEF, and the former Cinergy utilities each remaining a separate legal entity. The combined company will retain the name Duke Energy and will be headquartered in Charlotte; Progress and PEC will maintain a significant corporate and utility presence in Raleigh. At some point in the future, DEC and PEC intend to seek Commission approval to merge.

13. DEC's and PEC's respective retail rates and service will remain subject to the same degree of regulatory oversight and control by the Commission as under the pre-merger holding company structures. Further, any subsequent merger of DEC and PEC will be subject to the full authority of the Commission.

14. Known and potential benefits of the merger to North Carolina retail ratepayers, as well as to investors, include a favorable risk profile, greater diversification, and strong investment grade credit ratings for DEC and PEC that will lead to continued financial strength and reliable access to capital markets and an enhanced ability to construct and operate utility assets on reasonable financing terms.

15. The primary quantifiable benefits of the merger to North Carolina retail ratepayers consist of an estimated $364.2 million in total system fuel and fuel-related cost savings over the five-year period 2012 through 2016 through joint dispatch of DEC's and PEC's generation assets and an additional estimated $330.7 million in total system fuel and fuel-related system cost savings through sharing and implementing best practices for fuel procurement and use over the same five-year period.

16. The Stipulation guarantees that North Carolina retail ratepayers will receive their allocable share of $650 million of these cost savings, as well as a small amount of non-fuel

operations and maintenance (O&M) cost savings, over five years through DEC's and PEC's annual fuel clause proceedings. Within 30 days after the merger closes, DEC and PEC will apply for approval of fuel rate decrements to begin flowing to ratepayers a pro rata portion of the projected Year 1 savings set forth in merger application Exhibits 4 and 5. These decrements will remain in effect until fuel rates are adjusted in DEC's and PEC's first fuel clause proceedings following the close of the merger. Further, if the fuel and fuel-related savings achieved by DEC and PEC exceed the guaranteed $650 million during the first five years after the merger, then North Carolina ratepayers will receive their allocable share of the additional savings.

17. The Stipulation further provides that DEC and PEC will file monthly reports of tracked fuel savings with their monthly fuel reports under Commission Rule R8-52. The Supplemental Stipulation provides that if North Carolina retail ratepayers have not received their allocable share of the $650 million of guaranteed savings at the end of the five-year period and the decline in the price of natural gas has resulted in the delivery of less coal to certain DEC coal-fired plants, then the five-year period will be extended by 18 months and the remaining savings amounts will be reflected as an adjustment in DEC's and PEC's respective fuel charge proceedings or as a separate decrement in fuel rates as realized throughout the 18-month period.

18. In addition to the immediately quantifiable benefits of the merger to North Carolina retail ratepayers, substantial non-fuel O&M cost savings are expected to result from the integration of Duke and Progress over the long term. Additional known and potential benefits include economies of scale and scope and the leveraging of best practices, both of which are expected to result in operating efficiencies and improvements over time. These savings, which are less certain than savings associated with joint dispatch and other fuel and fuel-related cost savings, will be reflected in test period costs in future general rate cases and will help to mitigate the rate impact of cost increases such as those associated with plant additions and compliance with environmental regulations.

19. The integration process will involve workforce reductions as functions are consolidated and duplicate positions are eliminated. These workforce reductions are estimated to include the elimination of approximately 1,860 positions across the combined company, mostly in the Carolinas. The elimination of these positions is expected to account for a substantial portion of the non-fuel O&M cost savings resulting from the merger and will not compromise DEC's and PEC's service reliability, safety and dependability.

20. The Regulatory Conditions and Code of Conduct attached to the Stipulation are another benefit of the merger to North Carolina retail customers in that they update, consolidate, clarify, strengthen, and expand the existing Regulatory Conditions that were approved by the Commission for Duke and Progress in the Sub 795 and Sub 844 Orders, respectively.

21. In addition to the direct benefits to North Carolina retail ratepayers, the Stipulation includes commitments by DEC and PEC to provide annual community support and charitable contributions in their North Carolina service areas over four years in amounts no less than $9.2 million and $7.28 million, respectively, based on the average of each company's annual contributions over the 2006 through 2010 period. DEC and PEC have also committed to contribute a total of $15 million during the first year after the merger for purposes such as

workforce development and low income energy assistance in their service territories, to be allocated in proportion to the number of North Carolina retail customers served by DEC and PEC. In addition to the $15 million contribution, DEC and PEC shall contribute $2 million to NC GreenPower during the first year after the merger.

22. Known and potential costs and risks of the merger to North Carolina retail ratepayers include direct merger costs and other merger-related cost increases that could impact North Carolina retail rates; the potential for preemption of the Commission's regulatory authority under the FPA, particularly as it relates to the JDA and the Joint OATT, and under the Public Utility Holding Company Act of 2005 (PUHCA 2005); potential adverse effects on DEC and PEC of transactions within the holding company family and the resulting need for increased regulatory oversight of such transactions, including the treatment of joint dispatch costs and savings; the potential for DEC and PEC to unreasonably favor their unregulated affiliates over nonaffiliated suppliers of goods and services; potential adverse impacts on DEC's and PEC's cost of capital; the exposure of DEC, PEC, and their respective retail ratepayers to costs and risks associated with Duke, Progress, and their subsidiaries; and the potential for DEC's and PEC's quality of service to deteriorate because of increased management focus on cost savings and earnings growth.

23. The Commission-approved Stipulation, Regulatory Conditions and Supplemental Stipulation protect DEC's and PEC's retail ratepayers from payment of merger-related costs by (a) requiring that direct expenses associated with costs to achieve the merger be excluded from DEC's and PEC's cost of service for retail ratemaking purposes; (b) allowing DEC and PEC to seek recovery in future rate case proceedings of capital costs associated with system integration projects and with the adoption of best practices, including information technology, provided that such costs are incurred no later than three years from the close of the merger, only the net depreciated costs of such system integration projects at the time the request is made may be included and no request for deferrals of these costs may be made; however, the time limitation does not apply to DEC's capital costs associated with post-merger coal blending; (c) disallowing recovery of any merger-related employee severance costs in cost of service for retail ratemaking purposes; (d) requiring the exclusion of any acquisition adjustment that results from the merger; and (e) prohibiting the allocation of any costs associated with a failed merger.

24. The Commission-approved Regulatory Conditions effectively protect as much as reasonably possible the Commission's jurisdiction as a result of the merger, including risks related to agreements and transactions between and among DEC, PEC, and their affiliates, including the JDA; financing transactions involving Duke, DEC, or PEC, and any other affiliate; the ownership, use, and disposition of assets by DEC or PEC; participation in the wholesale market by DEC or PEC; and filings with federal regulatory agencies. In addition, they insulate DEC's and PEC's retail ratepayers as much as reasonably possible from any adverse consequences potentially resulting from the merger.

25. The Commission-approved Regulatory Conditions, Stipulation, and Supplemental Stipulation ensure that DEC's and PEC's retail ratepayers receive adequate benefits from the JDA and that joint dispatch costs and the sharing of cost savings can be appropriately audited.

26. The Commission-approved Stipulation, Regulatory Conditions and Code of Conduct effectively address as much as reasonably possible potential risks and concerns related to cost allocation and ratemaking arising from the merger, including ensuring that the costs incurred by DEC and PEC are properly incurred, accounted for, and directly charged, directly assigned, or allocated to their respective North Carolina retail operations.

27. The Commission-approved Stipulation and Regulatory Conditions provide appropriate and effective auditing and reporting requirements with respect to affiliate transactions and cost of service for retail ratemaking purposes.

28. The Commission-approved Stipulation, Regulatory Conditions and Code of Conduct effectively protect as much as reasonably possible DEC's and PEC's North Carolina retail ratepayers from the potential impacts of the merger relating to risks of transactions with and commitments of DEC, PEC and Duke to wholesale customers and other parties.

29. The Commission-approved Code of Conduct will effectively govern the relationships, activities, and transactions among DEC, PEC and their affiliates following the close of the merger.

30. The Commission-approved Regulatory Conditions effectively address as much as reasonably possible potential risks and concerns related to financing issues arising from the merger by ensuring that (a) neither DEC's nor PEC's capital structures and cost of capital are adversely affected because of their affiliation with Duke, each other, and other affiliates, and (b) both DEC and PEC have sufficient access to equity and debt capital at reasonable costs to adequately fund and maintain their current and future capital needs and otherwise meet their service obligations to their retail customers.

31. The Commission-approved Regulatory Conditions effectively address as much as reasonably possible potential risks and concerns related to corporate governance and ring-fencing issues arising from the merger by ensuring the continued viability of DEC and PEC and insulating and protecting DEC, PEC, and their retail ratepayers from the business and financial risks of Duke and the affiliates within the Duke holding company system, including the protection of utility assets from the liabilities of affiliates.

32. The Commission-approved Regulatory Conditions effectively enable the Commission to exercise its jurisdiction over business combinations involving Duke or other members of the Duke holding company family following the merger by ensuring that the Commission receives sufficient notice and opportunity to exercise its lawful authority.

33. The Commission-approved Regulatory Conditions effectively address as much as reasonably possible potential risks and concerns related to structure and organization arising from the merger by ensuring that the Commission will receive adequate notice of, and opportunity to review and take such lawful action as is necessary and appropriate with respect to changes to the structure and organization of Duke, DEC, PEC, and other affiliates, and nonpublic utility operations as they may affect North Carolina retail ratepayers.

34. The Commission-approved Regulatory Conditions provide appropriate and effective procedures for the implementation of conditions requiring advance notices and other filings arising from the merger.

35. The Commission-approved Regulatory Conditions effectively ensure monitoring of and compliance with their provisions, including the Code of Conduct, by requiring Duke, DEC, PEC, and all other affiliates to establish and maintain the structures and processes necessary to fulfill the commitments expressed in all of the Regulatory Conditions and the Code of Conduct in a timely, consistent, and effective manner.

36. The Commission-approved Regulatory Conditions effectively ensure that both DEC and PEC maintain a strong commitment to customer service following the merger.

37. The Commission-approved Regulatory Conditions effectively ensure that DEC's and PEC's North Carolina retail ratepayers are protected as much as reasonably possible from any adverse effects of any tax sharing agreement and receive an appropriate portion of any income tax benefits associated with services taken by DEC and PEC from an affiliated service company.

38. The Commission-approved Regulatory Conditions effectively ensure that after the merger the Commission and the Public Staff will continue to have access to the books and records of DEC, PEC, and other members of the Duke holding company system in accordance with North Carolina law.

39. The Commission-approved Regulatory Conditions and the provisions of the Stipulation protect DEC's and PEC's North Carolina retail ratepayers as much as reasonably possible from known and potential costs and risks of the merger and provide sufficient benefits to offset known and potential costs and risks.

40. The regulatory oversight and controls in place at the retail level are sufficient to protect retail ratepayers as much as reasonably possible from any potential retail market power effects of the merger.

41. The issue of wholesale market power was addressed by the Applicants' revised market power mitigation plan, and approved with changes and conditions by the FERC in its June 8, 2012 Market Power Order. The Stipulation, Regulatory Conditions, and Supplemental Stipulation protect retail customers from most, but not all, costs associated with the Applicants' revised wholesale market power mitigation plan. Therefore, in order to fully protect retail customers, the Commission will require two additional protections. First, the Commission will require DEC and PEC to demonstrate how provision I.A.(5) of the Supplemental Stipulation will be implemented. Second, the Commission will not allow PEC to charge retail customers any costs associated with the Greenville-Kinston Dupont 230-kV line until the later of June 1, 2017, or the actual in-service date of the facility.

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

The evidence supporting these findings of fact is contained in the application and in the testimony of Applicants witnesses Rogers and Johnson. These findings are essentially informational, procedural, and jurisdictional in nature and for the most part are not in dispute.

Pursuant to the Sub 129 Order, applicants for merger approval pursuant to G.S. 62-111 are required, among other things, to file a market power analysis employing the Herfindahl-Hirschman Index (HHI) or other accepted measurement and sensitivity analyses on the impact of significant factors on markets. Applicants are also required to file a "comprehensive list of all material areas of expected benefit, detriment, cost, and savings over a specified period (e.g., three to five years) following consummation of the merger." The purpose of such analyses is to assist the Commission in determining whether or not a merger meets the statutory standard for approval. The Commission stated in its Order dated April 27, 2011, that the application satisfied the filing requirements of the Sub 129 Order.

The Applicants stated in the application that the actual integration of Duke and Progress and their service companies is expected to produce cost savings in addition to those identified in the Compass Lexecon Study and the Fuel Synergies Review and that there will be upfront costs associated with achieving these savings. The fact that the application did not include a quantification of the costs and benefits associated with these non-fuel savings, along with the exhibits quantifying direct and immediate fuel savings, does not constitute a filing deficiency insofar as the Sub 129 Order is concerned. Moreover, as discussed below, the record contains ample evidence regarding the Applicants' estimates of both fuel and non-fuel savings to support a decision as to whether the merger meets the statutory standard for approval

The Commission, therefore, finds and concludes that Duke and Progress are lawfully before the Commission with respect to the relief sought in the application and that the merger filing requirements established in Docket No. M-100, Sub 129, with respect to the market power and cost-benefit analyses submitted with the application have been met.

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

The evidence supporting these findings of fact is contained in the application, the Merger Agreement and the testimony of Applicants witnesses Rogers, Johnson, and Good. These findings are essentially uncontroverted.

Through the application and supporting testimony, the Applicants described the process for accomplishing the merger and the holding company structure that will exist upon closing. The Applicants have indicated that the merger of DEC and PEC will not occur until a number of aspects of the utilities' operations are addressed. These include the determination of best business practices, operating procedures, equipment specifications, uniform rate schedules, service regulations, and computer systems. It is expected that the joint dispatch of generating assets and the coordination of activities related to fuel procurement and use, combined with general rate increases for DEC, will narrow the rate gap between DEC and PEC. Nevertheless, nothing in the record in this proceeding suggests that a merger between DEC and PEC is imminent. When such a business combination is proposed, it will be subject to Commission approval under G.S. 62-111(a).

The Commission, therefore, finds and concludes that the rates and service of DEC and PEC will remain subject to the same degree of regulatory oversight and control by the Commission under the proposed holding company structure as they were before the close of the merger.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding of fact is contained in the application and the testimony of Applicants witnesses Rogers, Johnson, and Good, and NCSEA witness Urlaub.

The Applicants state in the application that at the close of the merger the combined company will be the largest regulated electric utility in the United States. It will have the largest capitalization, the largest generating capacity, the largest nuclear generating capacity, and the largest number of customers of any group of affiliated regulated utilities in the Nation. Witnesses Rogers and Johnson testified that a larger and more diverse company with a strong balance sheet will have greater access to capital on favorable terms. Thus, the merger will enhance the Applicants' ability to construct and operate reliably the facilities needed to serve customers. The witnesses further testified that the greater size, scale and diversification of the combined company will translate into continued financial strength, significant operating cash flows, and strong investment grade ratings, all of which create an attractive investment opportunity for the debt and equity investors that are needed to finance utility operations.

Witnesses Rogers and Johnson testified that the utility industry faces an extended period of extremely large investments in infrastructure replacement, modernization and expansion. In order to meet the future demand for electricity, both companies will have to invest in new generation that will be more costly than the companies' current average embedded costs. PEC and DEC are well into this intense capital investment program. PEC is investing nearly $2 billion in new natural gas fueled generation. DEC is investing over $3 billion in new clean coal generation and natural gas fueled generation. Much of this generation is simply replacing aging plants that are no longer cost effective to operate. The companies also face significant cost increases in order to comply with new proposed Environmental Protection Agency regulations and Nuclear Regulatory Commission regulations. The resulting large infrastructure investment creates two challenges: (1) raising the capital necessary to finance the plant additions on reasonable terms; and (2) minimizing the costs to customers of building and operating these new plants. According to witnesses Rogers and Johnson, the merger of Progress and Duke will allow them to address both of these challenges and mitigate potential impacts.

Witnesses Rogers and Johnson explained that the combined company will not only have increased financial strength, a favorable risk profile, greater diversification, and strong investment grade credit ratings, it will also create operating efficiencies for PEC and DEC which will partially mitigate operating cost increases for both utilities. In addition, cost reductions will flow from the synergies produced by merging the service companies of the two Applicants, which will further help mitigate operating and maintenance cost increases. Thus, the merger will materially enhance PEC's and DEC's ability to construct the facilities their customers need today and in the future and to operate them in a reliable and cost effective manner.

Finally, witnesses Rogers and Johnson emphasized that an important operational benefit of the merger will be centralized management of the two companies' nuclear fleets. Duke operates seven nuclear units, and Progress operates five. Eleven of these 12 nuclear units are in the Carolinas—a geographic proximity that further strengthens the benefits of operating as one large nuclear fleet and particularly supports the combination of these two companies. Additionally, the depth and breadth of the combined nuclear management team and workforce will also enhance the combined company's ability to operate these plants safely, reliably and cost effectively.

Witness Good described the financial strength, credit quality, and liquidity of Duke and Progress as stand-alone, unaffiliated entities and discussed the positive effect of the merger on the financial aspects of the combined company. She stated that as of September 19, 2011, both companies had solid investment grade credit ratings, were in strong financial condition, and were expected to be able to meet their debt obligations on time and in full. Witness Good noted that both Duke and Progress operate in regulatory jurisdictions that support credit quality, and both have low business risk profiles characterized by predominantly rate-regulated utility businesses. She further stated that being the largest regulated utility in the country would translate into continued financial strength and flexibility for dealing with circumstances such as changing regulatory requirements, volatility in capital markets, economic downturns, and other external influences.

Witness Good testified that during challenging or volatile market conditions, debt investors tend to favor larger entities that are active in the capital markets, have more liquidity and carry strong investment grade credit ratings. The combined company will possess all of these. The combined company will also have more geographic and regulatory diversity and a larger portion of the business associated with regulated operations, which will translate into more stable cash flows and liquidity. This diversity and greater proportion of regulated operations will allow the company greater operational flexibility and the ability to deal with unforeseen circumstances.

Witness Good noted that the major risk factors that are faced by regulated utilities such as PEC and DEC are regulatory risk, economic risk and risk resulting from increased environmental or nuclear regulations. Additionally, there are significant financial risks associated with having to make large capital investments to fund infrastructure projects. She stated that the credit rating agencies believe DEC and PEC operate in generally supportive regulatory environments that will support long-term credit quality with timely and sufficient recovery for prudently incurred costs and expenses. However, she also noted that the credit rating agencies have clearly recognized the unique challenges of managing higher than normal capital expenditure programs and the prospect of more stringent environmental mandates among the issues that could affect the credit quality of regulated utilities. Witness Good observed that the increased size, diversity and financial strength of the combined company will significantly help mitigate these risks.

In addition, witness Good stated that the merger is expected to be accretive to earnings in year one, positioning the combined company in the 4% to 6% earnings growth range. The current Duke dividend policy will be maintained. These factors will equate to an attractive total shareholder return that will attract equity investors, thereby preserving reliable access to equity capital. Witness Good explained that, overall, the news of the merger has been well received by the equity analysts.

According to witness Good, both Moody's and Standard & Poor's (S&P) reviewed the proposed transaction and affirmed the credit ratings of the combined company and its subsidiaries as of the date of the merger announcement. She stated that size, scale, and financial strength are important to investors and should support the company's ability to attract capital on favorable terms. Good further stated that investors will benefit from more stable returns resulting from the fact that approximately 88 percent of Duke's business after the merger will be regulated, as opposed to 79 percent before. With respect to Progress, PEC, and Progress Energy Florida (PEF), Good testified that upon close of the merger S&P's CreditWatch with positive implications was expected to result in an upgrade to the companies' A- corporate credit rating, which will result in greater access to debt financing and a lower cost of debt than would otherwise be possible.

On cross-examination, witness Good stated that the rate of return or risk profile of the combined company should be less than the risk profile for the stand-alone companies because of the financial strength she described. However, she could not opine as to the quantification that would represent in a general rate proceeding.

NCSEA witness Urlaub testified that the merger is not motivated by potential fuel savings or any operational efficiency, citing the investment analyst reports attached to the application as Exhibit 2. He noted that the witnesses for the Applicants stressed stronger balance sheets, positive credit ratings and the enhanced ability to obtain capital at lower rates as central benefits from the merger. From this, witness Urlaub concluded that a primary motive for the merger is improving the financial standing of the combined companies to allow them to pursue a strategic plan involving investments in large, capital intensive generation, including new nuclear generation. NCSEA opposes this strategy. Urlaub further asserted that the primary benefit of the merger is financial and that the benefits, such as JDA savings and lower costs of capital are by-products of the main objective, rather than intended consequences. Nevertheless, although NCSEA opposes the merger, witness Urlaub acknowledged that the merger should produce real financial benefits and that such benefits should result in retail rates lower than those which would otherwise exist.

The Commission, therefore, finds and concludes that the merger will produce known and potential financial benefits for PEC and DEC in the form of continued financial strength, lower financing costs, and flexibility for dealing with changing circumstances. Such benefits should ultimately accrue to the benefit of PEC's and DEC's North Carolina retail ratepayers, as well as to the shareholders of the combined company. Although not quantifiable, these benefits are important to North Carolina ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15 - 17

The evidence supporting these findings of fact is contained in the application, Exhibits 4 and 5 to the application, the Stipulation, the Supplemental Stipulation, the testimony of Applicants witnesses Weintraub, Kalt, and Williams, the testimony of EDF, et al., witness Hahn and the testimony of Public Staff witnesses Morey and Hoard.

The Applicants stated in the application that the primary and most immediate quantifiable benefit of the merger will result from combined dispatch of DEC's and PEC's generation assets through the JDA, which is expected to reduce DEC's and PEC's fuel costs by approximately $364 million over the five-year period 2012 through 2016. These savings are the result of using the lower cost resources of each company to displace the higher cost resources of the other depending on the marginal cost of production of each utility's available resources in a given hour. In addition to the fuel savings expected to result from the joint dispatch of DEC's and PEC's generation resources, fuel synergy savings totaling $330.7 million are expected to be realized over five years, consisting of the following: $115 million through sharing and implementation of best practices for fuel procurement and use; $183.9 million through the application of coal blending practices to DEC's coal use; and a total of $31.8 million through coordinating use of DEC's and PEC's natural gas pipeline capacity, efficiencies in reagent procurement, and elimination of the need for DEC to establish a natural gas trading desk. The quantification of these savings is supported by Exhibit 4, the Compass Lexecon Study, and Exhibit 5, the Fuel Synergies Review.

The Stipulation provides that North Carolina retail ratepayers will receive their allocable share of $650 million of these fuel and fuel-related cost savings in varying amounts each year of the five-year period through DEC's and PEC's annual fuel clause mechanisms, beginning with immediate decrements to fuel rates to be filed by DEC and PEC within 30 days after the close of the merger. According to the Stipulation, these initial reductions will be based on the projected fuel and fuel-related cost savings set forth in Exhibits 4 and 5. These initial reductions will be based on a pro rata amount of Year 1 savings during the period between the close of the merger and the effective date of the rate changes in DEC's and PEC's next fuel clause proceedings. A new decrement will be determined at the time of each respective fuel clause proceeding during the five-year period. The Supplemental Stipulation provides that if North Carolina retail ratepayers have not received their allocable share of the $650 million at the end of the five-year period and the decline in the price of natural gas has resulted in the delivery of less coal to certain DEC coal-fired plants, then the five-year period will be extended by 18 months and the remaining savings amounts will be reflected as an adjustment in DEC's and PEC's respective fuel charge proceedings or as a separate decrement in fuel rates as realized throughout the 18-month period.

The Stipulation states that the guaranteed savings are anticipated to be achieved in six categories – coal blending, coal commodity savings, reagents, transportation, gas capacity, and the gas trading desk – but may include other merger-related savings related to joint dispatch and fuel procurement. The Stipulation also specifies the manner in which the various categories of savings will be determined, subject to ongoing review, refinement, and revision based on experience as savings are realized. Finally, the Stipulation provides that, in their monthly reports under Commission Rule R8-52, DEC and PEC will file monthly reports of tracked fuel savings on the following bases: total system, DEC, DEC North Carolina retail, PEC, and PEC North Carolina retail.

Applicants witness Weintraub testified that upon the closing of the merger PEC and DEC will begin significant coordination of their operations. These coordinated operations will produce significant operational efficiencies that will directly benefit customers. The primary, and most immediate, such benefit will result from transitioning individual dispatch of PEC's and DEC's generating assets to combined dispatch via a joint dispatch agreement.

Witness Weintraub testified that PEC and DEC have entered in to a Joint Dispatch Agreement (JDA) that was filed as Exhibit No. 3 to the Application. Consistent with the companies' reliability and contractual obligations as well as applicable laws and regulations, the JDA will allow DEC's and PEC's generation resources to be dispatched as a single system to meet the two utilities' retail and firm wholesale customers' requirements at the lowest reasonable cost. Under the JDA, DEC will act as the joint dispatcher for DEC's and PEC's power supply resources. The joint dispatch process will allow PEC and DEC to serve their retail and wholesale native load customers more efficiently and economically than they can on a stand-alone basis. Witness Weintraub explained that the JDA also provides a methodology for calculating the savings generated by the joint dispatch process and for equitably allocating the savings between DEC and PEC.

According to witness Weintraub, the JDA expressly provides that it is not intended to act as a system integration agreement and that DEC and PEC will retain their obligations to serve their own native load customers, to fulfill their own contractual obligations, and to operate their own transmission systems and balancing authority areas. DEC's and PEC's contractual obligations will not be changed by the JDA. This includes their contractual obligations under existing wholesale power contracts and their obligations under the Virginia-Carolinas (VACAR) reserve sharing arrangement. Thus, DEC and PEC will each retain the obligation to serve their own native load customers, fulfill contractual obligations, operate their own transmission systems, and retain their BAAs.

Witness Weintraub explained that the joint dispatcher will direct the dispatch of both DEC's and PEC's power supply resources, which include the parties' generation as well as their wholesale power purchases. In addition, the joint dispatcher will be responsible for making short-term (less than one year) wholesale power purchases and sales on behalf of DEC and PEC. DEC and PEC will retain individual responsibility for entering into wholesale power transactions of a year or longer. In carrying out its responsibilities under the JDA, the joint dispatcher is charged with achieving the most economic dispatch plan to serve DEC's and PEC's native load customers, consistent with the provision of reliable service, industry standards, and applicable laws and regulations. In effect, the joint dispatcher has the same goals as the individual utilities had prior to the implementation of the JDA. The difference is that the joint dispatcher will consider the loads and resources of both utilities, which will achieve a more economic result than the utilities could achieve on a stand-alone basis. The joint dispatch function will employ the same methodologies as the security-constrained economic dispatch function each company performs pre-merger. The post-merger process will simply integrate both companies' generation resources into the dispatch process.

According to witness Weintraub, in general, the joint dispatcher will not distinguish between the utilities' resources in determining how best to serve the combined loads of DEC and PEC. The joint dispatcher will have to consider various factors that might constrain the selection of power supply resources, such as contractual "must-run" obligations for certain resources. Within such parameters, however, the joint dispatcher will treat the resources of both utilities as available to serve the load of both DEC and PEC. To the extent that this results in one utility over-generating (i.e., producing more energy than its load) and the other utility under-generating, the imbalance will be handled through a dynamic schedule between the parties' balancing authority areas.

Witness Weintraub testified that each utility will bear the costs associated with its own power supply resources, as defined under the JDA. For example, DEC and PEC will incur the fuel and O&M costs associated with their own generating facilities. Similarly, each utility will be responsible for the costs it incurs under its own power purchase contracts. After the fact, it will be determined which utility (over-generating utility) provided energy to the other, how much it supplied to the other utility (under-generating utility) in a given hour, and the amount of the savings. The under-generating utility will compensate the over-generating utility at cost for all its expenses for providing the energy. In order to prevent one utility from unfairly shifting costs to the other and to ensure a reasonable sharing of the savings generated by the joint dispatch, an after-the-fact process will be used to allocate costs and benefits between the utilities.

Under the after-the-fact allocation process for each hour, the joint dispatcher allocates energy to three types of transactions that occurred during the hour: 1) New Non-Native Load Sales; 2) Existing Non-Native Load Sales; and 3) Native Load Sales. The energy allocation process is done in descending order of energy cost (other than energy from "must-run" units) and identifies which power supply resources will be deemed to have served each class of transaction. Once the energy allocation process is complete, the joint dispatcher applies cost allocation provisions contained in the JDA to achieve a reasonable allocation of the costs and benefits of the joint dispatch.

The after-the-fact allocation process determines for each hour the costs each company would have incurred if its resources had been dispatched on a stand-alone basis, without regard to any Non-Native Load sales opportunities. The difference between the joint dispatch costs and the stand-alone costs represents the cost savings achieved by joint dispatch. These savings then are allocated between PEC and DEC based on each company's share of energy generated in each hour.

Witness Weintraub stated that the joint dispatch savings will automatically flow through to the utilities' retail customers through their respective fuel clause proceedings. He also explained that, upon the closing of the merger, both PEC and DEC will file rate decrements to pass through the forecasted fuel savings for 2012.

Under the joint dispatch process, the energy cost attributable to each utility's native load will be the costs actually incurred by the utility for energy allocated to native load service, adjusted by the cost allocation payments calculated by the joint dispatcher, which will be treated as payments for energy transfers between the utilities. Thus, the energy cost ultimately incurred by each utility to serve its native load will be equal to the stand-alone costs it would have incurred but for the joint dispatch arrangement, less the utility's share of the joint dispatch savings. That will be the amount that each utility passes through its retail fuel clause and native load wholesale contracts. This process will result in an annual flow through of the joint dispatch savings for both retail and wholesale customers.

On cross-examination by the Commission, witness Weintraub testified that if the fuel and fuel-related savings achieved by DEC and PEC exceed the guaranteed $650 million during the first five years after the merger, then North Carolina ratepayers will receive their allocable share of the additional savings.

Regarding the estimated savings resulting from the joint dispatch arrangement, Applicants witness Kalt testified that the Compass Lexecon Study relied on a commonly used security-constrained dispatch production cost model to run optimized least cost production for DEC's and PEC's individual BAAs on a stand-alone basis and then ran the same model assuming joint dispatch across BAAs, holding constant assumptions about such things as load, fuel prices, and existing contracts. Witness Kalt explained that a net reduction in the total production costs required to serve both DEC's and PEC's loads represents estimated savings attributable to joint dispatch, driven largely by optimizing dispatch so as to minimize fuel costs. He further explained that lower fuel costs result because joint dispatch creates a larger, more flexible pool of operating assets from which to draw when making dispatch decisions for both utilities, and it enhances the ability to commit and substitute available capacity at a less costly unit in one BAA for a more costly unit that would otherwise be required to serve load in the other BAA absent joint dispatch.

According to the Compass Lexecon Study, total system savings over five years attributable to joint dispatch, using base case assumptions, are expected to be as follows: 2012 – $38 million; 2013 – $49 million; 2014 – $64 million; 2015 – $97 million; and 2016 – $116 million. Witness Kalt testified that to understand the sensitivity of results to input assumptions, Compass Lexecon examined the effect of changing fuel prices and load growth, which are the primary drivers of future variable generation costs. He stated that results of this analysis showed estimates of five-year joint dispatch savings ranging from $249 million with low load growth to $629 million with high fuel prices. He further stated that he considered the estimated savings of $364 million to be conservative for several reasons. One, multiple sensitivity analyses show that changes in underlying input savings generally result in higher estimated benefits. Two, the dispatch model does not capture additional sources of benefits associated with joint dispatch as well as ancillary benefits to society in general through enhanced economic activity.

EDF, et al., witness Hahn testified that the benefits of the JDA are more uncertain than portrayed by the Applicants and could be achieved absent a merger of the holding companies. Therefore, he recommended that the JDA benefits not be accepted as justification for the merger.

He also recommended that the JDA be revised to base the joint dispatch on a single BAA or, if the Commission does not believe a single BAA is desirable, that the Applicants be required to conduct modeling that accurately simulates the proposed JDA, as the merger would have adverse effects on the environment.

Witness Kalt asserted, both in direct testimony and in rebuttal to witness Hahn, that the use of joint dispatch as contemplated by the JDA is a benefit not realistically available absent the merger. He stated that the joint unit commitment and dispatch process represents a set of complex, interacting, day-to-day, real-time, moment-to-moment decisions that cannot be made without bringing decisions under common control through a merger. He explained that joint dispatch requires the sharing of competitively sensitive generation operating costs and a level of cooperation not practical between unaffiliated utilities. According to witness Kalt, the information needed to achieve the results of the JDA without merging is not publicly available. Most of the data are reported after the fact, with some available only on an annual basis, in contrast to the JDA, which requires DEC and PEC to use detailed real-time and projected load, resource, and operation date in the unit commitment and dispatch process. He stated that the utilities can operate and dispatch units in a way that is not possible absent a merger. Regarding witness Hahn's suggestion that DEC and PEC might implement a JDA-type arrangement by transferring functional and operational control of their generation assets to a third party (as in forming an ISO or RTO), witness Kalt stated that this would require separate and specific Commission and other regulatory approvals and could involve additional expenses that would offset joint dispatch savings. He also refuted witness Hahn's claim that the Compass Lexecon Study modeled one BAA. He stated that this was not accurate, clarifying that this type of modeling is not based on any assumptions about BAAs other than to the extent that generation assets are associated with BAA boundaries. Rather, according to witness Kalt, Compass Lexecon's modeling mapped transmission and generation of the DEC and PEC systems without regard to legal or physical boundaries. Inputs were based on physical transmission facilities, transfer capabilities, and constraints that occur in a security-constrained economic dispatch. Witness Kalt also did not agree with witness Hahn's assertion that having one BAA would produce even greater cost savings, calling this assertion speculation and the analysis and figures inconsistent with the JDA as proposed. Applicants witness Weintraub also refuted witness Hahn's claim that the retention of three BAAs prohibits DEC and PEC from conducting joint dispatch as modeled by Compass Lexecon. Witness Weintraub described this contention as "simply wrong," and stated that DEC and PEC will conduct one unit commitment plan and a single security-constrained economic dispatch to serve the combined loads of both DEC and PEC regardless of whether there are three BAAs or one BAA.

Finally, Applicants witnesses Kalt and Williams disagreed with witness Hahn's contention that the JDA would have adverse effects on the environment. Witness Kalt stated that the modeling results do contain a projection of increased coal use – 9.3 million MWh out of 893 million MWh of total generation over five years – which he described as a *de minimis* amount. However, he explained that the composition and nature of joint dispatch savings depend on a multitude of factors, including actual composition and characteristics of supply resources, relative fuel prices, and emission control regimes. He further stated that DEC and PEC will continue to comply with all applicable state and federal emission control regulations and that having a broader base and variety of generation assets available under the JDA will enhance their ability to serve loads in an economical and efficient manner while complying with emissions requirements. Similarly, witness Williams testified that both DEC and PEC currently plan and operate their systems in a manner designed to meet the electricity needs of their customers in a least cost manner while complying with all environmental laws. He stated that the JDA simply provides additional tools and flexibility to achieve this objective more efficiently and that emissions restrictions on plants will not change as a result of the merger. The plants will still be subject to the Clean Smokestacks Act, other North Carolina air restrictions, regulations of the Department of Environment and Natural Resources, the federal Clean Air Act, and Environmental Protection Agency regulations.

Public Staff witness Morey testified that the use of security-constrained economic dispatch for both DEC's and PEC's generation fleets can be expected to benefit customers by systematically increasing the use of lower-cost, more efficient generating units, and demand-side resources where available, relative to higher-cost, less efficient units. He stated that this can lead to lower fuel costs, lower O&M costs, and reduced emissions than would result from the commitment and dispatch of DEC's and PEC's generating units separately. He further stated that additional savings may also be realized to the extent joint dispatch enables DEC and PEC to lower their respective operating reserves.

Witness Morey also testified that, technically speaking, production costs savings through joint dispatch could be achieved absent the merger, but some of the terms would likely be different. He stated that the principal barriers to achieving joint dispatch benefits absent a merger are transaction costs and operational separation. Moreover, according to witness Morey, a joint dispatch agreement absent a merger could be construed as creating a two-utility power pool in which all transactions are made at wholesale, which would put the terms and conditions of joint dispatch and the pricing of that generation under the FERC's jurisdiction. The proposed JDA, however, contains specific language requiring each utility to continue to serve its own native load customers with the lowest cost resources available within its own generation fleet, and only the provision of energy between DEC and PEC after the lowest cost energy from each utility's resources has been dedicated to serve its native load is to be considered a wholesale transaction between them. He further stated that the proposed JDA affords the principal advantage over pre-merger transactions of permitting the dispatch of DEC's and PEC's generation fleets in real time, on an hour-to-hour basis, which will enable DEC and PEC to capture savings that could not be realized if they were engaging each other in bilateral wholesale market transactions that are not so readily adjusted to real-time circumstances.

Witness Morey presented the results of his review of the Compass Lexecon Study and testified that he reviewed it to determine the accuracy of the estimated savings and the sensitivity of the estimate to key assumptions made by Compass Lexecon. Witness Morey stated that he began his analysis by replicating the results of the study using the security-constrained least-cost dispatch program used by Compass Lexecon, which is the Day-Ahead Locational Market Clearing Prices Analyzer (DAYZER), and the input data used by Compass Lexecon to conduct the study. He further testified that the results from his analysis matched the five-year savings estimated by Compass Lexecon for the Pre-Merger Case and the Joint-Dispatch Case. Witness Morey also ran the DAYZER model using the input files provided by Compass Lexecon for the sensitivity cases and obtained results identical to those shown in the Compass Lexecon Study.

Witness Morey stated that he then reviewed the reasonableness and the accuracy of the assumptions regarding operating characteristics, fuel prices, load forecasts, and transmission line transfer capability and constraints used by Compass Lexecon for the Pre-Merger Case and the Joint-Dispatch Case. With the exception of transmission constraint assumptions, he checked the values used by Compass Lexecon for each category of variables against the values for the same variables that were provided to the Public Staff through discovery in connection with DEC's and PEC's 2010 Integrated Resource Plans in Docket No. E-100, Sub 128, and information provided by DEC and PEC to the Public Staff in connection with their 2010 filings in the avoided cost proceeding in Docket No. E-100, Sub 127. According to witness Morey, these comparisons revealed differences in the following generator unit characteristics: heat rates, expected outage rates, forced outage rates, and variable emission rates. He also found significant forecast differences with respect to 2013 and 2014 delivered coal prices. However, he stated that, when he reran the DAYZER program with changes to the input files, he found that the resulting savings were nearly identical to those obtained by Compass Lexecon. Finally, with respect to firm transmission assumptions, Morey concluded that the differences between firm reservations assumed in the model and existing firm reservations did not appear to be significant enough to cause a material difference in the estimated production cost savings in the Joint Dispatch Case.

Witness Morey testified that he did not necessarily agree with Compass Lexecon's assertion that the projected joint dispatch savings are conservative, since a base case should represent a middle ground – a kind of "50/50" forecast between optimistic and pessimistic scenarios - based on the most likely set of circumstances for all key factors that influence the cost of joint dispatch. Morey stated that he identified several assumptions that may not have been consistent with this principle, as well as other anomalies and "quirks" associated with Compass Lexecon's analysis. Further, he noted two shortcomings or limitations to the Study. First, the DAYZER model does not respect firm transmission rights that may limit the actual ability of DEC and PEC to jointly dispatch their generation fleets to serve both of their loads at least cost. Thus, according to witness Morey, the analysis may overstate the production cost savings, depending on the extent to which DEC and PEC are able to take advantage of non-firm transmission available on a short-term basis over the next five years. Second, the analysis did not model off-system sales and purchases in either the Pre-Merger Case or the Joint Dispatch Case, though it was not clear to Morey what the impact of such modeling would have been.

As a result of his review and assessment of the Compass Lexecon Study, witness Morey concluded that Compass Lexecon's analysis of production cost savings benefits that can be derived from joint dispatch of DEC's and PEC's combined generation fleets was conducted appropriately and that its estimate of the production cost savings arising from joint dispatch is a reasonably accurate representation of the potential savings that can be achieved over the period 2012 through 2016. He further concluded that improving or correcting the data and assumptions about which he had concerns would have little impact on the estimated savings.

With regard to monitoring the implementation of the JDA, witness Morey recommended that DEC and PEC provide the Public Staff with detailed information concerning the model that will be used to simulate the production costs of DEC and PEC on a stand-alone basis, verify the accuracy of the model by benchmarking it against a recent historical period of stand-alone generation dispatch, notify the Public Staff at least quarterly when significant changes have been made to the model, and provide the Public Staff with all information necessary to audit the model at least monthly until the utilities have gained experience with the model and then at least quarterly thereafter. This recommendation is included as a provision of the Stipulation.

Public Staff witness Hoard testified that the total amount of joint dispatch savings projected in the Compass Lexecon Study is $364.2 million over five years. He stated that he had estimated the savings for North Carolina retail ratepayers over this period to be a total of $247.6 million, $147.2 million for DEC and $100.4 million for PEC. Witness Hoard presented two examples to illustrate the proposed accounting for transactions under the JDA for fuel clause purposes, explaining that the seller will treat the transactions as intersystem sales and the buyer will treat them as an economic power purchase with only fuel and fuel-related costs being reflected in a fuel clause proceeding. As shown in these examples, both the seller and the buyer are made whole with respect to costs incurred and both receive an appropriate share of the savings.

With respect to fuel synergies, Applicants witness Weintraub testified that the estimated additional $330.7 million savings in combined fuel costs will be achieved through transporting, procuring, managing, and blending fuels and procuring reagents in conjunction with increased and broader purchasing ability. He stated that these fuel procurement savings could not be achieved absent the merger, which allows for greater purchasing capacity than either utility has standing alone, as well as the sharing of proprietary information not shared by non-affiliates for competitive reasons. Weintraub explained that both DEC and PEC have transportation contracts with common carriers and that by aligning the lowest rates across common contracts and carriers and taking advantage of opportunities to maximize economies of scale for the transportation of DEC's and PEC's combined coal requirements, the utilities can reduce their coal transportation costs. Similarly, by optimizing a combined fuel sourcing plan with greater scope across common coal suppliers, DEC and PEC together can reduce coal procurement costs. Witness Weintraub further stated that both DEC and PEC utilize common suppliers and transportation providers for limestone, and that by leveraging increased limestone volumes, the utilities expect to lower its delivered cost by reducing both commodity and transportation costs. In addition, DEC and PEC intend to increase its purchasing power by consolidating ammonia volumes to achieve more competitive commodity and transportation pricing. Regarding natural gas transportation costs, he stated that DEC and PEC will utilize common natural gas transportation paths and complementary logistics for each of their natural gas generation fleets, and by maximizing the use of the combined portfolio of natural gas transportation agreements, will achieve cost savings through the short-term and potential long-term capacity releases into the market. He further stated that utilizing non-firm interstate pipeline capacity will also enable DEC and PEC to avoid additional fixed pipeline costs.

With regard to coal blending, witness Weintraub explained that PEC has invested over $60 million in scrubbed coal units over the past five years to improve fuel flexibility, thus expanding the types of coal that can be reliably burned and creating competition among coal basins. He stated that this has resulted in lower fuel procurement costs and increased blending capabilities to achieve optimal quality blends and procurement economics, and that the integration of these best practices will reduce fuel costs for the combined companies.

On cross-examination, witness Weintraub explained that the effect of PEC's ability to burn a wider range of coal types on the amount of coal burned would depend on the characteristics of the coal burned. He agreed, however, that different coal characteristics affect the price of coal and could affect the emissions produced by the coal. He further agreed that no analysis of NO_x, SO_x, or SO_2 was performed as part of the joint dispatch analysis and stated that no analysis had yet been conducted of post-merger emissions as a result of the proposed fuel synergies.

EDF, et al., witness Hahn contended that PEC and DEC could achieve the fuel blending savings without merging. This assertion was rebutted by witness Weintraub. He explained that there are two primary reasons all of these savings opportunities, including fuel blending savings, could not be achieved absent the merger. First, the merger of Duke and Progress will allow for much greater purchasing efficiencies than either company possesses standing alone. Second, as with the JDA, the merger allows the sharing of proprietary information that unaffiliated companies do not willingly share due to competitive concerns. For example, after several years of blending coal for its plants, PEC has developed certain coal blending skills and practices that can be adopted by DEC and that will facilitate and hasten the application of coal blending practices to DEC's coal use. PEC has spent considerable time and money investing in the people and equipment to develop these coal blending abilities that are allowing it to lower its coal costs substantially. These proprietary skills and practices give PEC a competitive advantage and are valuable assets, which PEC would normally not share with unaffiliated entities.

Specifically with regard to fuel blending savings, witness Weintraub stated that while it is possible that DEC may have at some point in the future implemented fuel blending absent the merger, the merger ensures that DEC will do so much more quickly and efficiently than would otherwise have been the case. PEC has been blending fuel since 2006. As a result, DEC will benefit from PEC's experience, mistakes and successes. This will allow DEC to immediately adopt best practices as well as select the best technologies and equipment. With this knowledge of lessons learned and best practices, DEC will be able to start the fuel blending process in a much shorter time frame than would otherwise be possible. Moreover, the combined companies will be able to achieve greater economies of scale and scope in their fuel blending operations. To achieve these efficiencies and savings, the companies would need to share confidential commercial information that would not be possible without a merger.

Witness Weintraub explained that in 2012 the North Carolina retail pro rata share of the $650 million in guaranteed savings will be provided to PEC's and DEC's retail customers through a decrement rate rider filed following the closing of the merger. The rider will be designed to provide their retail customers the forecasted savings to be realized from the joint dispatch of their systems as well as other fuel costs savings during calendar year 2012. In each of DEC's and PEC's 2012-2016 fuel cost proceedings, they will incorporate the forecasted savings from the joint dispatch of their systems as well as other fuel costs savings for each of those years into the calculation of their respective fuel factors. They will also factor into the calculation of their respective annual Experience Modification Factors a true-up of the forecasted amounts for the previous year to the actually experienced savings. The actually achieved savings will be determined in the manner described in the Stipulation. At the close of 2016, if actually achieved savings do not total North Carolina's pro rata share of the $650 million in guaranteed savings, witness Weintraub testified that PEC and DEC will flow through their respective fuel riders their allocated share of the remaining obligation in their 2017 fuel cases. However, the Supplemental Stipulation provides that if North Carolina retail ratepayers have not received their allocable share of the $650 million in guaranteed savings at the end of the five-year period and the decline in the price of natural gas has resulted in the delivery of less coal to certain DEC coal-fired plants, then the five-year period will be extended by 18 months and the remaining savings amounts will be reflected as an adjustment in DEC's and PEC's respective fuel charge proceedings or as a separate decrement in fuel rates as realized throughout the 18-month period. This final "true-up" payment will ensure that North Carolina retail customers receive their guaranteed share of the savings. It is important to note that, in the event the actual savings exceed the guarantee, those additional savings will also be flowed through to DEC's and PEC's customers.

Commercial Group witness Chriss recommended that the Commission alter the Stipulation and require PEC and DEC to guarantee annual fuel and fuel-related savings amounts. Applicants witness Weintraub rebutted this proposal. Weintraub testified that savings should be reflected in rates as they occur. They should not be provided either in advance or in arrears. Otherwise, because the annual forecasted savings will never exactly match actual annual savings, if annual guarantees are made, it will be necessary to use deferred accounting to track the difference between forecasted and achieved savings. Such deferred accounting introduces an additional level of accounting complexity in general and creates financial reporting issues if a rate case is pending. Witness Weintraub further explained that both witness Kalt and Public Staff witness Morey confirmed the veracity of the forecasted JDA savings and fuel procurement, transportation and fuel blending savings.

Public Staff witness Hoard testified that the projected $330.7 million in five-year fuel synergy savings consists of the following: transportation – $40.6 million; coal blending – $183.9 million;[1] coal price commodity savings – $74.4 million; natural gas pipeline capacity savings – $17.0 million; reagents – $12.8 million; and avoided cost of a DEC natural gas trading desk – $2.0 million. Witness Hoard stated that, except for a small amount of savings due to the elimination of the need for a separate DEC trading desk, DEC and PEC will reflect the actual amount of the additional fuel and fuel-related cost savings in their respective fuel clause proceedings. He also stated that the only new or special accounting entries that might be recorded by the utilities will result from capacity release credits received from the sharing of gas pipeline capacity.

In supplemental testimony, Public Staff witness Hoard, as well as Applicants witness Weintraub, each explained how certain provisions of the Supplemental Stipulation clarify and amend the Stipulation with respect to the fuel and fuel-related cost savings. First, Public Staff witness Hoard testified that economy purchases were not included in the Compass Lexecon Study that formed the basis of the fuel savings guarantee and such purchases were not addressed in the Stipulation. Based on the clarification related to economy purchases contained in the Supplemental Stipulation, witness Hoard testified that PEC and DEC can make economy

[1] According to witness Hoard, the utilities have projected five-year CTA of $50.8 million to implement coal blending at three DEC generating plants.

purchases that benefit ratepayers and receive credit for purposes of calculating the $650 million fuel savings guarantee. Witness Weintraub also testified that the actual savings resulting from such purchases will flow through DEC's and PEC's annual fuel charge adjustment proceedings in the same manner that such lower costs/savings have been treated prior to the merger. The second clarification of the Supplemental Stipulation concerns the increased consumption of reagents by DEC resulting from the greater use of coal blending. Witness Hoard stated that the Fuel Synergies Study included as Exhibit 5, which was part of the basis of the $650 million fuel savings guarantee, did not include the additional reagent costs that would be incurred as a result of coal blending. Witness Hoard and witness Weintraub each testified that the Supplemental Stipulation clarifies that these increased reagent costs would not be netted against the fuel savings guarantee and that DEC and PEC would be allowed to recover their reasonable and prudently incurred reagent costs in their respective annual fuel charge adjustment proceedings. Witness Weintraub also noted that Appendix B of the Supplemental Stipulation clarifies how savings realized by DEC from greater use of coal blending are to be calculated for the purpose of the $650 million system fuel savings guarantee. Finally, witness Hoard and witness Weintraub each noted that the current price of natural gas is low and if such prices continue, it is likely that DEC and PEC will use less coal than was assumed at the time of the Stipulation. Thus, DEC and PEC will have less potential to realize fuel savings from coal commodity purchases, coal transportation, and coal blending. As a result, the Supplemental Stipulation amends the last sentence in Paragraph 2(a) of the Stipulation such that if, at the end of the five-year period, DEC and PEC have not achieved all of the $650 million in guaranteed savings and the price of natural gas has resulted in less coal being delivered to certain DEC coal-fired plants, then the five-year period will be extended by 18 months and the remaining savings will be reflected in DEC's and PEC's respective fuel charge proceedings or as a separate decrement in fuel rates as realized throughout the 18-month period. In summary, Public Staff witness Hoard testified that the Supplemental Stipulation effectively preserves the benefits of the Stipulation.

Finally, in further supplemental testimony, Applicants witness Weintraub testified that none of the modifications required by FERC alter the ability of the Applicants to achieve the fuel savings described in previous testimony or otherwise impair any of the benefits of the JDA to North Carolina customers.

The Commission is of the opinion that the results of the Compass Lexecon Study, which was subjected to rigorous analysis by Public Staff witness Morey, are a reasonable estimate of the production cost savings that can be achieved by DEC and PEC under the proposed JDA and that such savings cannot realistically be achieved without the merger. Further, the Commission is of the opinion that under the terms of the Stipulation and the Supplemental Stipulation the actual savings resulting from joint dispatch of DEC's and PEC's generation assets can be accurately identified and tracked by the utilities and monitored by the Commission and the Public Staff.

The Commission concludes that the forecasted fuel procurement, fuel transportation and fuel blending savings are real and substantial. These savings, combined with the JDA savings, total nearly $700 million over the five-year period 2012-2016. The only issue raised by the intervenors regarding these fuel procurement, transportation and blending savings was witness Hahn's assertion that the coal blending savings could potentially be achieved in the absence of the merger. The Applicants persuasively rebutted witness Hahn's suggestion. In addition, through the Stipulation the Applicants have guaranteed their Carolinas' customers $650 million of these savings.

On cross-examination witness Chriss agreed that in addition to the $650 million in guaranteed savings, the Stipulation contains numerous benefits for North Carolina customers, including comprehensive Regulatory Conditions, a commitment that Progress and Duke will continue current levels of community support for four years, and make a $15 million contribution to community colleges and low income energy assistance. Further, the Commission concludes that the Stipulation and Supplemental Stipulation entered into by the Applicants and the Public Staff, PEC and DEC, guaranteeing to provide North Carolina and South Carolina customers $650 million of the forecasted $695 million in savings over the five-year period 2012-2016 greatly mitigates any concerns regarding the accuracy of the JDA and other savings forecasts. In addition, it provides a substantial benefit to PEC's and DEC's North Carolina customers that is not available to any other Duke or Progress customers.

The Commission, therefore, finds and concludes that the merger will produce direct and immediate benefits to North Carolina retail ratepayers in the form of a substantial reduction in fuel and fuel-related costs that will be passed on through fuel clause proceedings.

In their post-hearing Brief, EDF, et al., proposed additional conditions for approval of the merger, including requiring Applicants to revise the language of the JDA to base the joint dispatch on a single BAA, and if necessary, require the Applicants to provide an updated economic analysis of the revised JDA; or if the Commission does not believe a single BAA is desirable, require the Applicants to conduct modeling that accurately simulates the proposed JDA. The Commission is not persuaded that the JDA needs to be based on a single BAA for DEC and PEC. Further, the Commission is of the opinion that the Compass Lexecon Study provides a reasonably accurate estimate of the production cost savings that can be achieved by DEC and PEC under the proposed JDA. Therefore, the Commission is not persuaded that the proposed additional conditions recommended by EDF, et al., are reasonable or appropriate.

In their post-hearing Brief, EDF, et al., proposed additional conditions, designated as Proposed Conditions 2.a.-c., for approval of the merger. These proposed conditions would require Applicants to mitigate the alleged increased emissions from coal-fired generation under the merger and JDA by requiring Applicants to conduct an analysis of the increased coal plant emissions from expansion of coal blending practices and increased dispatch of coal-fired generation that will result from the merger and JDA; requiring Applicants to study the potential for accelerated coal retirements based on coordinated resource planning, reserve sharing agreements, and lower operating reserves under the JDA; and directing DEC and PEC to retire all coal units that are identified for retirement in each utility's 2011 IRP on a schedule to be determined by the Commission. However, on June 18, 2012, EDF, et al., filed comments in which they stated that since the filing of their post-hearing Brief, EDF, et al., entered into a settlement agreement with the Applicants that resolved the issues between them in the South Carolina proceeding. As a result of this settlement agreement, EDF, et al., stated that they desired to withdraw Proposed Conditions 2.a.-c.

In its post-hearing Brief, the Commercial Group asserted that the Applicants should guarantee the annual amount of fuel savings they project, particularly as the witnesses for the Applicants have testified that they have a high degree of confidence that they will achieve these savings. The Commercial Group cites witness Kalt's estimate that joint dispatch savings (base case) will be $38 million in 2012, $49 million in 2013, $64 million in 2014, $97 million in 2015 and $116 million in 2016. However, the Commission is not persuaded that projections should be used to determine the amount of savings flowed back to ratepayers each year. Rather, savings should be reflected in rates as they occur. They should not be provided either in advance or in arrears. Otherwise, because the annual forecasted savings will never exactly match actual annual savings, if annual guarantees are made, it will be necessary to use deferred accounting to track the difference between forecasted and achieved savings. Such deferred accounting introduces an additional level of accounting complexity in general and creates financial reporting issues if a rate case is pending.

In their comments filed on June 18, 2012, EDF, et al., expressed concern that the Supplemental Stipulation extends the time period for customers to receive the $650 million of guaranteed savings from five years to possibly six and one half years, if at the end of the five-year period DEC and PEC have not achieved all of the $650 million in guaranteed savings and the price of natural gas has resulted in less coal being delivered to certain DEC coal-fired plants. EDF, et al., noted that this change means that ratepayers might have to wait longer than originally provided under the Stipulation to receive the benefits of the merger.

In the Applicants' reply comments filed on June 19, 2012, the Applicants noted this concern of EDF, et al., and also noted that EDF, et al., did not mention that in consideration of the extension of the guaranteed savings period the Applicants agreed, among other things, to forego the opportunity to seek recovery of merger related severance costs that will total over $226 million.

The Commission is not persuaded that the possible extension of the time for customers to receive the $650 million of guaranteed savings from five years to possibly six and one half years materially decreases the benefit of the guaranteed $650 million in savings. The Commission finds and concludes that this provision of the Supplemental Stipulation is reasonable in light of the reduced cost of natural gas. Considered as a whole, the provisions of the Stipulation and the Supplemental Stipulation effectively preserve the benefits of the $650 million in savings. Therefore, the Commission is not persuaded that the additional conditions recommended by EDF, et al., in their post-hearing Brief are reasonable or appropriate.

The Commission, therefore, finds and concludes that the estimated $364.2 million savings in total system fuel and fuel-related costs during the first five years of operation of the JDA due to the joint dispatch of DEC's and PEC's generation assets and the additional estimated $330.7 million of system fuel and fuel-related synergy savings are reasonable estimates of the primary quantifiable benefit of the merger. Any issues regarding the accuracy of these estimates, whether such savings could be achieved absent the merger, and concerns over increased emissions were persuasively rebutted as described above. Further, the Commission concludes that any concerns with respect to the accuracy or reasonableness of these cost savings and benefits are greatly mitigated by the Stipulation and Supplemental Stipulation that guarantee North Carolina retail ratepayers will receive their allocable share of $650 million of the cost savings through DEC's and PEC's fuel charge adjustment proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18 – 19

The evidence supporting these findings of fact is contained in the application, the testimony of Applicants witnesses Rogers, Johnson, and Sims, the testimony of Public Staff witness Hoard, the testimony of EDF, et al., witness Hahn and Items 1-16, 1-19, and 1-20 of the Applicants' responses to the Commission's Post-Hearing Order.

The Applicants state in the application that cost savings in addition to the $694 million in joint dispatch and fuel synergy savings will be created upon the actual integration of Duke and Progress and their service companies. These savings will occur over time as a result of the combination and assimilation of information technology systems, supply chain functions, corporate and administrative programs, and inventories. The application further states that future savings in these areas are expected to be significant and will benefit retail ratepayers in future rate proceedings by helping to offset rate increases associated with fleet modernization programs and compliance with new regulatory requirements.

On November 17, 2011, in response to the Commission's November 2, 2011 Post-Hearing Order, the Applicants filed an updated internal study of merger integration savings. The study was entitled Preliminary Cost Savings Opportunity. It was included as Attachment 1-16 to the Applicants' November 17, 2011 response. This study showed risk adjusted O&M savings and O&M costs to achieve (CTA) for Years 1 through 3 broken down by risk of achievement or anticipated realized. The total potential savings and CTA shown for each year are as follows: Year one ─ $186 million in savings and $273 million in CTA; Year two ─ $289 million in savings and $229 million in CTA; and Year three ─ $355 million in savings and $185 million in CTA. The resulting net amounts shown in the updated internal study are as follows: Year one ─ $87 million in net costs; Year two ─ $60 million in net savings; and Year three ─ $170 million in net savings. Summing the net amounts over the three years in question reveals net savings of $143 million.

Public Staff witness Hoard presented several tables containing estimates provided by the Applicants of corporate-wide savings and CTA in three areas: JDA savings, fuel synergy savings, and non-fuel O&M savings. Savings and costs shown on these tables were summarized by account type: Capital Costs, Cost Pools, and O&M. Hoard explained that capital cost savings reflect costs that are assumed to be avoided due to lower construction overhead charges and lower material and contractor costs expected from leveraging greater purchasing power. He stated that North Carolina retail ratepayers will receive DEC's and PEC's shares of the benefits from these savings because their rate base investments will be lower than they would be absent the merger. According to Hoard, capital account CTA reflect investments in information technology and other resources that are necessary to achieve savings. He noted that a utility typically recovers capital costs over a period of years through depreciation and amortization charges to income and indicated that DEC and PEC would likely propose to roll the undepreciated amount of these costs into rates when they file rate cases.

Public Staff witness Hoard explained that O&M account type costs consist of expenses charged to income during the current period. He stated that a major source of O&M savings is lower payroll costs resulting from the elimination of duplicate positions, and that a major CTA is severance payments. He further stated that severance payments are treated for financial reporting purposes as periodic expenses, but for ratemaking purposes are often excluded from cost of service due to the fact that they are of a non-recurring nature.

Regarding ratepayer benefits related to non-fuel O&M savings resulting from the merger, Public Staff witness Hoard stated that it is likely that both DEC and PEC will file rate cases over the next several years, due in large part to extensive plant construction. According to Hoard, the present savings should help to reduce the amounts of the increases in those cases.

According to the application, Duke and Progress will manage workforce reductions resulting from the merger through normal retirements, employee attrition, voluntary retirement programs, and similar programs to the maximum extent possible.

Applicants witnesses Rogers and Johnson testified that while there inevitably will be workforce reductions, the merger will benefit the majority of employees of both companies in the long term and the short term because it will create a financially stronger company that is better able to manage the transformation occurring in the industry and better able to provide competitive employee compensation and benefits. They reiterated that to mitigate the impact of the workforce reductions the Applicants were fully committed to taking advantage of natural attrition and retirement, pledging to manage the integration process in a thoughtful, rational way that treats all employees fairly.

Applicants witnesses Rogers and Johnson explained that Progress and Duke are both known as good places to work and to enjoy a long and fulfilling career. Over the last hundred years, both organizations have developed a positive culture of high employee engagement with very strong emphasis on safety, integrity and service. They testified that as a combined company the Applicants will be able to build on this positive tradition and be even better-positioned to attract and retain the talent needed for this new era of tremendous change and challenge in the industry. Rogers and Johnson stated that a significant benefit of the merger for employees will be a larger, more diverse company that will create greater opportunities for career growth, development and advancement.

With respect to the types of positions and functions that will be affected, Applicants witnesses Rogers and Johnson stated that most of the reductions would be in corporate staff functions, rather than operational functions, that is, down where the work is done in terms of the generating plant and distribution operations. They further stated that they were not going to reduce workforce or investment in any way that would undermine safety and service reliability and that the mission given to the integration teams was to keep in mind the need to continue to operate the way they have historically, in as reliable and safe a manner as possible.

Applicants witness Sims testified that once the Merger Agreement was signed, the Applicants created merger integration teams consisting of subject matter experts for the functional areas of the two companies. These teams were charged with determining the best means of integrating the companies and the resulting savings opportunities and potential employee impact. Sims reiterated the Applicants' commitment to managing the integration process in a way that treats employees fairly and stated that, to that end, the Applicants were offering a voluntary severance plan to a substantial number of employees. With respect to the types of positions that might be eliminated, she cited the potential adoption by PEC of a DEC best practices approach with respect to PEC's hydro fleet that could result in ten fewer positions at PEC's hydro plants. The employees in those positions would be eligible for voluntary severance and could have the opportunity to relocate to other areas of the company. She emphasized, however, that the work of the integration teams was a dynamic work in process, and that more information would be available in a month or so about the positions that would be eliminated.

When asked whether the integration team had studied how the elimination of positions would impact reliability and dependability of electric service, Applicants witness Sims stated that when she and her integration team co-chair, A.R. Mullinax, gave instructions to their integration leads, they asked them to work together to identify best practices and opportunities for savings, but started the process by saying that safety, reliability, and customer service are important to their business. Sims further stated that they wanted to form not only the largest utility but also the best utility, and that they expected safety, reliability, and customer service to continue.

With respect to the merger causing the elimination of jobs, Applicants witness Sims stated that the integration team was currently analyzing job reductions resulting solely from the merger of the holding companies and, as part of that process, the team was looking at where there are duplicative jobs and best practices that could be implemented. She further stated that it was hard to predict what would happen when DEC and PEC are merged in the future, as they look at implementing best practices and improving efficiency every year, regardless of whether there is a pending merger.

Public Staff witness Hoard testified that the integration team's internal study of non-fuel O&M savings resulting from the merger was a three-year study incorporating a risk factor that measured the probability of realizing the targeted savings. He further testified that approximately 45 percent of the estimated three-year gross non-fuel O&M savings are expected to result from workforce reductions, which represents a five percent reduction in force on a risk adjusted basis, i.e., incorporating a risk factor that measures the probability that certain savings may not be achievable.

On cross-examination, witness Hoard stated that the Public Staff did not analyze the effect of job losses resulting from the merger in terms of lost income tax revenue, increased cost of unemployment benefits, or social services needed by those who had lost their jobs. Rather, the Public Staff focused on the effects of the merger on utility service and ratepayers as a whole. Hoard stated that his job, as an accountant, was to analyze the estimates of merger savings produced by the Applicants' studies.

EDF, et al., witness Hahn contended that the merger application was not complete because it did not include greater detail regarding the costs and benefits resulting from these non-fuel synergies and did not contain a mitigation strategy for the North Carolina workforce reductions.

Applicants witness Sims addressed witness Hahn's concerns and further elaborated upon non-fuel integration savings and the related workforce reductions. First, she explained why the Applicants did not seek to quantify and include these savings in the merger application. She testified that the application and supporting testimony describe two separate categories of merger related savings. In the first category are the near-term benefits which consist of the fuel and operating cost savings realized from the joint dispatch of PEC's and DEC's generating resources; the fuel procurement savings; fuel transportation savings; and savings from coal blending by DEC. These activities are forecasted to produce $695 million in savings during the first five years following consummation of the merger. Witness Sims explained that detailed studies supporting these savings were filed with the merger application. In the second category are the non-fuel O&M savings from consolidation and merging of various corporate functions, in particular those performed by DEBS and PESC, the two service companies. Sims testified that the amount and timing of these savings are much less certain that the fuel and fuel-related savings.

Several intervenors asked the Commission to require the Applicants to take specific steps to mitigate the impact of job losses resulting from the merger. The IBEW, in its Statement of Position, criticized the Stipulation for failing to guarantee any level of employment for the Duke and Progress employees working in North Carolina. The IBEW contended that the Stipulation should not be approved until it guarantees that the merger will not result in involuntary layoffs and that the operational workforce will be maintained at a level that ensures reliability and dependability.

EDF, et al., witness Hahn recommended that the Commission require the Applicants to file a mitigation plan as a condition of the merger, contending that conditioning merger approval on additional investment in energy efficiency and clean energy would generate additional jobs to offset job reductions resulting from the merger.

Attachment 1-19 to the Applicants' November 17, 2011 filing in response to the Commission's Post-Hearing Order shows that as of November 2011 Duke and Progress together have a total of 29,177 employee positions and that projected position reductions due to the merger over a three-year period total 1,860 (970 in year one, 435 in year two, and 455 in year three). Estimated vacancies of 368 leave projected headcount reductions (position reductions less vacancies) of 1,492 (1,860 - 368 = 1,492). This attachment also shows that 8,177 employees are eligible for the Voluntary Severance Plan (VSP). Assuming a 14 percent take rate for planning purposes based on previous Duke and Progress buyout packages, the number of VSP takers is estimated at 1,145. Additional reductions to address the potential gap between the projected headcount reductions and VSP takers (1,492 - 1,145 = 347) will be handled through normal attrition and involuntary severance.

In Item 1-20 of the Applicants' November 17, 2011 filing, the Applicants state that the integration process will continue after the merger closes, and it is anticipated that additional opportunities to implement best practices, eliminate duplication, and achieve efficiencies will be identified. While such opportunities may result in further position reductions, the Applicants state that they cannot predict when or how such reductions will occur, and no analysis has been conducted of potential reductions associated with combining Duke's and Progress's service companies or DEC and PEC.

The Commission is mindful of the fact that workforce reductions are an inevitable consequence of business combinations of the kind proposed by Duke and Progress in this proceeding. The Commission is also aware, as indicated by Public Staff witness Hoard and others, that a major source of O&M savings expected to be realized from the merger is lower payroll costs resulting from the elimination of duplicate positions. As a result of those cost savings, and other savings and benefits as discussed elsewhere in this Order, DEC's and PEC's North Carolina retail ratepayers are expected to receive significant potential benefits from the merger, and such benefits are expected to substantively outweigh the CTA. The Commission, therefore, in consideration of the foregoing and the entire record in this proceeding, finds and concludes that the potential workforce reductions at issue are reasonably necessary, unavoidable, and justified by the weight of the evidence in this proceeding.

In their post-hearing brief, EDF, et al., recommended that the Commission adopt additional conditions for approval of the merger. Several of these proposed conditions, designated as Proposed Conditions 3.a.-d., would require Applicants to mitigate the impact of job losses by making additional investments in energy efficiency. Another proposed condition, designated as Proposed Condition 5, would require additional investments in the clean energy sector. However, on June 18, 2012, EDF, et al., filed comments in which they stated that since the filing of their post-hearing Brief, EDF, et al ., entered into a settlement agreement with the Applicants that resolved the issues between them in the South Carolina proceeding. As a result of this settlement EDF, et al ., stated that they desired to withdraw Proposed Conditions 3.a.-d.

The Commission is of the opinion that this merger proceeding is not the proper forum in which to determine whether additional renewable energy expenditures should be required of PEC and DEC. The Commission is further of the opinion that this proceeding is not the proper forum in which to decide what types and how much, if any, additional renewable energy PEC and DEC should procure as part of their generation resource portfolios.

Pursuant to G.S. 62-110.1 and G.S. 62-133.9, the State's utilities are required to select the least cost mix of resources to meet the electricity needs of their customers. The Commission conducts annual IRP proceedings, pursuant to Commission Rule R8-60, for purposes of investigating the utilities' resource plans. These annual IRP proceedings are the proper forum in which to consider whether new resources - coal, natural gas, solar, wind, nuclear, or other - should be purchased or built by a public utility to meet forecasted demand.

The Commission also conducts annual proceedings, pursuant to Commission Rule R8-67, to evaluate, review and approve PEC's and DEC's efforts and plans to comply with the REPS requirements of Senate Bill 3. Those proceedings are the proper forum in which to consider the solicitation process used by PEC and DEC to obtain renewable energy resources and evaluate their decisions and plans for compliance.

In addition to the fact that these dockets are not the proper forum in which to address the additional requirements recommended by EDF, et al., the Commission is further of the opinion that the record in this proceeding is simply not adequate to allow the Commission to reach fully-informed, well-reasoned decisions of the nature requested by EDF, et al.

In their post-hearing brief, EDF, et al., further recommended that the Commission require the Applicants to file with the Commission the Booz Total Cost Study and/or the Integration Studies before the Commission approves the merger. However, the Commission is not persuaded that the filing of these studies would provide any additional information needed by the Commission or the parties. The Commission recognizes that the non-fuel O&M savings projections shown in the Applicants' studies represent only the latest results of an ongoing process. In addition, the Commission notes that these projections are based on certain assumptions and are subject to several caveats, to wit: the results remain estimates, the CTA may increase, regulatory decisions may impact some savings opportunities, and the results do not reflect the impact of potential future federal regulations or other unforeseen costs. Thus, these non-fuel O&M savings are considerably less certain than the fuel and fuel-related cost savings likely to be achieved over the five-year period of 2012 through 2016.

The Commission, therefore, finds and concludes that the merger is reasonably likely to produce significant non-fuel O&M cost savings and that such savings would ultimately accrue to the benefit of PEC's and DEC's North Carolina retail ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence supporting this finding of fact is contained in the application, the Stipulation, the Regulatory Conditions and Code of Conduct and the testimony of Public Staff witness Hoard. The Regulatory Conditions and Code of Conduct are attached to this Order as Appendix A.

As stated in the preamble, the Regulatory Conditions set forth commitments made by the Applicants as a precondition to approval of the merger and are to be interpreted in the manner that most effectively fulfills the exercise of the Commission's general supervisory authority over public utilities under Chapter 62 of the General Statutes of North Carolina. The various sections of the Regulatory Conditions are specifically intended to ensure that DEC's and PEC's North Carolina retail ratepayers are protected as much as reasonably possible from any known adverse effects of the merger and from potential costs and risks resulting from the merger, and that they receive sufficient benefits from the merger to offset any potential costs and risks resulting from the merger.

Public Staff witness Hoard testified that he had reviewed the existing Regulatory Conditions and Codes of Conduct currently approved for DEC and PEC and the Regulatory Conditions and Code of Conduct that were attached to the merger application and the Stipulation. He stated that as a regulatory accountant he would prefer that Duke, Progress, and their affiliates be subject to the Regulatory Conditions and Code of Conduct attached to the Stipulation rather than either of the other two sets of Regulatory Conditions and Codes of Conduct presently in effect.

The Commission agrees with witness Hoard that from a regulator's perspective the stipulated Regulatory Conditions and Code of Conduct are preferable to those that apply to DEC and PEC today.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The evidence supporting this finding of fact is contained in the application, the Merger Agreement, the testimony of Applicants witnesses Rogers and Johnson, the Stipulation, the testimony of Public Staff witness Hoard, the testimony of NC WARN witness Colton, the rebuttal testimony of Applicants witness Williams, and the post-hearing briefs.

In the application, Duke and Progress stated that the corporate headquarters for the combined company will be in Charlotte, North Carolina, with the continuation of a significant presence in Raleigh, North Carolina. The Applicants contended that, with the merger, the Carolinas will benefit from an industry leader being headquartered in North Carolina and from the philanthropic, cultural, and civic support associated with such a major corporate presence. Section 1.07 (d) of the Merger Agreement, attached as Exhibit 1 to the application, provides as follows:

> (d) Community Support. The parties agree that provision of charitable contributions and community support in their respective service areas serves a number of their important corporate goals. During the two-year period immediately following the Effective Time, Duke and its subsidiaries taken as a whole intend to continue to provide charitable contributions and community support within the service areas of the parties and each of their respective subsidiaries in each service area at levels substantially comparable to the levels of charitable contributions and community support provided, directly or indirectly, by Duke and Progress within their respective service areas prior to the Effective Time.

Applicants witnesses Rogers and Johnson testified that the combined company would maintain its strong, long-standing philanthropic leadership and economic development support in the communities that DEC and PEC serve. Paragraph No. 3 of the Stipulation provides as follows:

> 3. Annual Community Support and Charitable Contributions. DEC and PEC will provide annual community support and charitable contributions in North Carolina for four years from the close of the Merger at a level no less than $9.2 million and $7.28 million, respectively, based on the average of each company's annual contributions over the past five years (2006-2010).

No party took issue with this provision of the Stipulation.

In addition, with respect to continued community support to be provided by the combined company, Paragraph No. 4 of the Stipulation provides:

> 4. Other Contributions. DEC and PEC will contribute a total of $15 million dollars during the first year following the close of the Merger for purposes such as workforce development and low income energy assistance. The $15 million will be allocated between DEC's and PEC's North Carolina service territories in proportion to the number of North Carolina retail customers served by each.

On cross-examination, Public Staff witness Hoard testified that his understanding of Paragraph No. 4 of the Stipulation was that it is comparable to Regulatory Condition No. 75 approved by the Commission in Docket No. E-7, Sub 795 (Sub 795 Order), in connection with the Duke-Cinergy merger, and that the Public Staff was expecting guidance from the Commission on how the funds would be distributed.

In the Duke-Cinergy merger proceeding, DEC proposed to share $117,517,000 of five-year net merger savings with its North Carolina retail ratepayers through a one year across-the-board decrement. The Public Staff recommended that $5 million of this amount be distributed as follows: $2 million to DEC's Share the Warmth, Cooling Assistance, and Fan-Relief Programs; $2 million for conservation and energy efficiency programs to be submitted to the Commission for approval; and $1 million to NC GreenPower. In Regulatory Condition No. 75, the Commission required DEC, as a condition of the merger, to implement a one-year across-the-board decrement in rates in the amount of $117,517,000 and to contribute $12 million to various energy and environmental related and economic and educationally beneficial programs as follows: $6 million to DEC's Share the Warmth, Cooling Assistance, and Fan-Heat Relief programs; $2 million for conservation and energy efficiency programs to be approved by the Commission; $2 million to the Community College Grant Fund; and $2 million to NC GreenPower. The $12 million contribution was to be borne by DEC's shareholders. The Commission directed that DEC, the Public Staff, and the Attorney General confer and jointly develop a list of appropriate and cost-effective energy efficiency programs and submit them for Commission approval.

DEC subsequently requested that agencies receiving funds for Share the Warmth, Cooling Assistance, and Fan-Heat Relief be allowed to use those funds for other programs as well, noting that under the existing Share the Warmth and Cooling Assistance programs, funds could be used only for energy bills. DEC indicated that a focus group of 15 agencies had identified the following uses for the funds: energy bills, weatherization costs, energy equipment purchases (e.g., air conditioning units and space heaters), vendor payments (e.g., electricians to hook up or repair systems or equipment), deposit assistance, agency capacity and infrastructure (e.g., part-time staff) to handle more clients, educational materials, and joint bulk purchases of energy equipment for all energy assistance agencies. DEC stated that the funds would be distributed to the Foundation for the Carolinas, which would then distribute the funds to the agencies using the normal allocation process. DEC would execute a memorandum of understanding with each of the agencies specifying the use of the funds, and the Foundation for the Carolinas would provide an annual report to DEC on how the funds were used. The Public Staff recommended that DEC's proposal for distribution and expanded use of the funds be approved but that assistance with delinquent bills, deposits, and hookups be given priority over weatherization in the list of items for which the funds could be used. The Commission agreed with the Public Staff and by Order issued July 18, 2006, approved the proposal with this proviso.

Numerous public witnesses testified at the hearing in this proceeding advocating that the Commission address the needs of low-income customers by providing assistance in reducing their energy consumption and payment of their electricity bills. In addition, NC WARN witness Colton, contending that the merger will have an adverse impact on low-income customers, stated that the proposed $15 million contribution for workforce development and low-income energy assistance was not sufficient to overcome such adverse impact. Consequently, Colton recommended two mitigation measures: (a) a $27 million per year payment to the North Carolina Housing Finance Agency for ten years to supplement low-income weatherization and (b) an Arrearage Management Program (AMP) fully funded through a deferred cost recovery mechanism and borne by the general body of ratepayers.

In rebuttal testimony, Applicants witness Williams testified that the present proceeding is not the first time NC WARN has proposed creation of such a public benefits fund (PBF). Williams explained that in the fall of 2008, NC WARN proposed adoption of a PBF to fund an independently administered energy efficiency program and that the Commission, after considering the comments of numerous parties, in its December 2, 2008 Order in Docket No. E-100, Sub 120, concluded that "the Commission lacks sufficient statutory authority to compel the establishment and funding of an independently administered energy efficiency program such as that proposed by NC WARN. Moreover, the Commission determines that establishment of such a program at this time is inconsistent with the provisions of Senate Bill 3 and the intent of the General Assembly expressed therein." According to Williams, nothing has changed to alter the Commission's previous conclusion in Docket No. E-100, Sub 120.

With respect to the AMP recommended by NC WARN, witness Williams testified that both DEC and PEC presently have options available to assist customers with resolving arrearages. Williams explained that both utilities offer installment payment plans, equal payment plans, credit extensions, and other assistance to help customers with payment of past-due bills and that the utilities do not propose elimination of any of these currently available options.

In their post-hearing Brief, EDF, et al., asserted that in order to mitigate the impact of the merger on low-income customers the Commission should require an additional contribution from the shareholders of the new combined company for the purpose of funding low-income weatherization, in an amount to be determined by the Commission.

In its post-hearing Brief, with respect to the stipulated $15 million in other contributions, NCSEA contended that the stated purpose of the fund remains too vague and the funding level too small to mitigate the potential harm presented by the merger to low-income residents and any similarly-situated entities, such as some small businesses. NCSEA requested that the Commission evaluate and consider, among other mitigating measures, the creation of a third-party administered PBF to address the financial impacts of the merger on these customer groups.

The Commission determines that the needs of low-income customers to manage their energy usage and be financially able to pay their bills are undeniably real and substantial, and the agencies and individuals who are committed to addressing those needs, particularly in times of economic hardship and high unemployment, have a considerable undertaking to manage. However, the Commission does not agree with witness Colton that the merger will adversely affect those customers or that conditions of the merger approval should be a major vehicle for addressing their energy needs. As discussed elsewhere in this Order, the Commission is persuaded that the merger will result in significant quantifiable benefits in the form of cost savings that will be reflected in rates for all customers in fuel clause and general rate case proceedings. These savings will help to mitigate the impact of cost increases over time. The Commission is also persuaded that the Applicants' commitments in the proposed Regulatory Conditions, along with the Commission's Rules and Regulations and monitoring by the Commission and the Public Staff, are sufficient to ensure that there is no diminution of resources to assist low-income customers and other customers of DEC and PEC.

Further, the Commission is not persuaded that the mitigation measures recommended by NC WARN, EDF, et al., or NCSEA are reasonable or appropriate in this proceeding. The Commission agrees with witness Williams that nothing has changed since the Commission issued its December 2, 2008 Order in Docket No. E-100, Sub 120, in regard to the adoption of a PBF. With regard to witness Colton's proposed AMP, the Commission observes that both DEC and PEC have options available to assist customers with resolving arrearages and that the utilities do not propose elimination of any of these currently available options. For these reasons, the Commission declines to adopt the two mitigation measures recommended by Colton or the mitigation measures proposed by EDF, et al., and NCSEA. Furthermore, as discussed elsewhere in this Order, many of the mitigation methods proposed by NC WARN, EDF, et al., and NCSEA relate to service quality, customer service, energy efficiency, or customer assistance programs which can be more appropriately addressed in DEC's and PEC's annual IRP, DSM/EE and REPS proceedings. Nevertheless, the Commission strongly encourages and expects DEC and PEC to actively consider and propose for Commission approval as part of their DSM/EE portfolios programs that are specifically targeted to assist low-income customers.

With respect to the Applicants' agreement to contribute $15 million during the first year after the merger for purposes such as workforce development and low-income energy assistance, the Commission finds and concludes that the $15 million shall be divided as follows: $10 million to low-income energy assistance and $5 million to workforce development.

DEC and PEC shall contribute $10 million to low-income energy assistance programs. This $10 million should be allocated between DEC's and PEC's service territories in proportion to the number of North Carolina retail customers served by each. As was requested in Docket No. E-7, Sub 795, DEC should work with the Foundation for the Carolinas in administering its low-income energy assistance programs for DEC's proportional share. PEC should work with a local community foundation, the North Carolina Community Foundation, in administering its low-income energy assistance programs for PEC's proportional share. The community foundations should provide a report to DEC and PEC as to how the funds were used. DEC and PEC shall file the community foundations' reports with the Commission upon receipt.

DEC and PEC shall contribute $5 million to a Community College Grant Fund. This $5 million should be allocated between DEC's and PEC's service territories in proportion to the number of North Carolina retail customers served by each. DEC should work with the Foundation for the Carolinas to administer the grants to community colleges in its service territory. PEC should work with the North Carolina Community Foundation to administer grants to community colleges in its service territory. DEC and PEC shall file a report on the grants awarded pursuant to this condition within one year after the close of the merger.

In addition to the $15 million contribution for workforce development and low-income energy assistance agreed to in the Stipulation, DEC and PEC shall contribute $2 million to NC GreenPower. The $17 million in total contributions shall not be charged to DEC's and PEC's regulated utility operations, but shall be borne by the Applicants' shareholders.

The Commission, therefore, finds and concludes that the commitments by the Applicants in Paragraph Nos. 3 and 4 of the Stipulation, as well as the additional $2 million contribution to NC GreenPower, represent additional benefits of the merger to the communities DEC and PEC serve in North Carolina and should be approved. The Commission declines to adopt the mitigation measures proposed by NC WARN, EDF, et al., and NCSEA, as such additional measures or contributions are not necessary or warranted as part of the merger.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence supporting this finding of fact is contained in the application and the testimony of Applicants witness Williams.

The known and potential costs and risks to North Carolina retail ratepayers from a merger affecting one or more regulated electric utilities have been well documented in prior merger proceedings.[1] These previously identified potential costs and risks include the following: direct merger costs and other cost increases that could impact North Carolina retail rates; the potential for preemption under the FPA and under PUHCA 1935 and PUHCA 2005; potential adverse effects on DEC's and PEC's retail ratepayers as a result of transactions within the holding company family and the resulting need for increased regulatory oversight of such transactions; the potential for DEC and PEC to unreasonably favor their unregulated affiliates over nonaffiliated suppliers of goods and services; potential adverse impacts on DEC's and PEC's cost of capital; the exposure of DEC and PEC and their respective retail ratepayers to costs and risks associated with Duke, Progress and their subsidiaries; and the potential for DEC's and PEC's quality of service to deteriorate because of increased management focus on cost savings and earnings growth. In addition, this merger presents issues with respect to the JDA and Joint OATT that have not been presented in other merger proceedings.

NCSEA witness Urlaub testified that a primary motive for the merger is to improve the financial standing of the combined companies to allow them to pursue a strategic plan involving investments in large, capital intensive generation, including new nuclear generation. He further testified that the uncertainty created by this strategic plan produces significant risks that have associated costs. In addition, he identified the following risks: the real possibility of a double dip

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[1] See, e.g., Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, 96 NCUC 183 (Docket No. E-7, Sub 795, March 24, 2006); Order Approving Merger and Issuance of Securities, 90 NCUC 187 (Docket No. E-2, Sub 760, August 22, 2000); Order Approving Merger and Issuance of Securities, 89 NCUC 384 (Docket No. G-5, Sub 400, December 7, 1999); Order Approving Merger and Issuance of Securities, 89 NCUC 306 (Docket No. E-22, Sub 380, October 18, 1999).

recession, a smaller economic recovery than first projected, reduced demand, rising costs, and the much stronger positioning of alternative energy resources.

EDF, et al., witness Hahn testified that a result of the merger would be market dominance by the merged entities with regard to the procurement of renewable energy, leading to unaffiliated renewable energy developers foregoing North Carolina development activities. He asserted that a single-procurer market with affiliates active in the market for renewables creates an exclusive barrier to entry and does not foster a process that guarantees that the lowest cost or most favorable projects are built. As a result, the merger would have an adverse impact on the development and procurement of renewable energy in North Carolina.

In rebuttal, Applicants witness Williams testified that NCSEA's opposition to the specific utility assets in which DEC and PEC plan to invest is a risk that NCSEA faces regardless of the merger, the safeguard for which is the Commission's integrated resource planning (IRP) procedures and the requirement that a utility obtain a certificate of public convenience and necessity (CPCN) before beginning the construction of a new generating unit. As a result, Williams stated that this is not a risk created by the merger but, rather, is a matter that should be addressed in the Commission's IRP and CPCN proceedings.

With respect to witness Hahn's concerns, Applicants witness Williams testified that EDF, et al., are concerned that PEC will cease using requests for proposals to procure renewables from third parties and adopt DEC's approach of considering both self-build and third party generators. Williams testified that eliminating self-build options does not benefit retail ratepayers and that, in the final analysis, this debate is simply not appropriate for this merger proceeding. Contrary to witness Hahn's position, Williams asserted that existing statutes and Commission rules would continue, after the close of the merger, to impose on DEC and PEC the obligation to solicit the best and most cost effective projects. Therefore, concerns such as those expressed by Hahn are more appropriately addressed in the annual demand-side management/energy efficiency (DSM/EE) and Renewable Energy and Efficiency Portfolio Standard (REPS) proceedings, rather than in a vacuum in this unrelated proceeding.

Based on the foregoing, the Commission is not persuaded that the list of known and potential costs and risks of the merger to North Carolina retail ratepayers should be expanded beyond those stated in Finding of Fact No. 22. Specifically, the Commission finds and concludes that the list of known and potential costs and risks of the merger do not include the risks identified by NCSEA witness Urlaub and EDF, et al., witness Hahn, for the reasons discussed below.

Many of the risks cited by witness Urlaub, including the possibility of a double dip recession, a smaller economic recovery than first projected, reduced demand, rising costs, and the much stronger positioning of alternative energy resources are risks both DEC and PEC face today and will continue to face irrespective of whether the merger is consummated. They do not stem from the merger itself. In addition, Urlaub's linkage of the financial benefits of the merger to a commitment to a strategic plan to build new nuclear generation is not supported by the record in this proceeding. Urlaub presumes that a commitment to such a strategic plan would result directly from the merger, and then he asserts that the uncertainty this strategic plan creates is a significant risk of the merger. However, any link between the merger and the Applicants' future investments in nuclear generation is too tenuous to support such a conclusion. In addition, the Applicants' commitment to such a strategic plan, if it did exist, could not be accomplished without clearing the regulatory hurdles associated with the construction of nuclear generation.

The risk asserted by witness Hahn with respect to the effects on the market for procurement of renewable resources hinges on his assumption that the merger will cause DEC and PEC to purchase from affiliated interests that are in competition with renewable resource developers. Citing the FERC's stated belief that affiliate preference, or the possibility thereof, harms competition, whether in purchase power agreements or asset acquisitions, Hahn recommended that the Commission adopt a procurement process that follows the FERC's guidelines with respect to competitive solicitations for the portion of REPS compliance that would have been handled separately by PEC and DEC before the merger. However, the Commission is not persuaded that the merger will increase the renewable energy purchasing power of PEC and DEC, or otherwise materially alter their REPS requirements or processes. PEC and DEC are required to meet their REPS renewable energy obligations in the least cost manner. In doing so, they minimize the rate impact to their customers of complying with this statutory mandate. In addition, to the extent the merger allows PEC and DEC to lower their REPS compliance costs through more efficient resource procurement procedures, this will be a direct benefit to their North Carolina customers. Further, Hahn's recommendation appears to be based on the erroneous assumption that allowing a utility to propose a self-build renewable option is the equivalent of allowing a utility to purchase from an affiliate. To the contrary, there is no evidence that North Carolina regulatory laws and policies have allowed utilities to engage in imprudent or unreasonable purchases of capacity or energy from affiliated generators.

The Commission, therefore, finds and concludes that the merger will create certain known and potential costs and risks to North Carolina retail ratepayers, as stated in Finding of Fact No. 22. However, following the close of the merger DEC and PEC will each continue to have the same obligations they had before the merger to refrain from favoring or subsidizing their affiliates, to pursue the most reliable, prudent and cost-effective resources and projects, and to demonstrate that they have done so in appropriate proceedings before the Commission, such as IRP, CPCN and REPS proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The evidence supporting this finding of fact is contained in the Stipulation, Regulatory Conditions and Code of Conduct, the Supplemental Stipulation, the direct and supplemental testimony of Public Staff witness Hoard, and the supplemental testimony of Applicants witness Weintraub.

The Stipulation, Regulatory Conditions and the Supplemental Stipulation protect DEC's and PEC's retail ratepayers from payment of merger-related costs by specific provisions that:

(1) Require direct expenses associated with costs to achieve the merger (direct merger costs) to be excluded from DEC's and PEC's cost of service for retail ratemaking purposes;

(2) Allow DEC and PEC to seek recovery in future rate case proceedings of capital costs associated with system integration projects and with the adoption of best practices, including information technology, provided that such costs are incurred no later than three years from the close of the merger and only the net depreciated costs of such system integration projects at the time the request is made may be included and no request for deferrals of any costs may be made;

(3) Disallow recovery of any merger-related employee severance costs in cost of service for retail ratemaking purposes;

(4) Require the exclusion of any acquisition adjustment that results from the merger; and

(5) Prohibit the allocation of any costs associated with a failed merger.

As provided in Paragraph No. 12 of the Stipulation, the direct merger costs, which the Applicants have agreed to exclude from DEC's and PEC's cost of service for retail ratemaking purposes, would be composed of change-in-control payments made to terminated executives, 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.

Paragraph No. 12 of the Stipulation provided that with respect to capital costs such as system integration costs (largely from new information technology) associated with costs to achieve (CTA) merger savings, DEC and PEC would have been allowed to request recovery through depreciation or amortization in the first application for a general rate case filed by each of them after the close of the merger and prior to December 31, 2013. In order to justify such cost recovery, DEC and PEC would need to show that these capital costs resulted in quantifiable cost savings to their respective North Carolina retail customers greater than the revenue requirement effect of the inclusion of these costs in rate base. Further, the Stipulation provided that coal-blending CTA were treated the same as other capital CTA, such that DEC and PEC could seek recovery of coal-blending costs in the first general rate case filed by each utility after the closing of the merger and prior to December 31, 2013. However, because the decline in the price of natural gas is now likely to result in DEC taking delivery of fewer tons of coal at the plants identified in the Fuel Synergies Review for coal-blending modifications, and, therefore, DEC's investments in those modifications are likely to be delayed, Public Staff witness Hoard testified in his supplemental testimony that the Public Staff has now agreed to remove the previously imposed limitation. Consequently, the Supplemental Stipulation provides that the normal ratemaking standards applicable to all capital investments be used for the coal-blending CTA. The revised coal-blending CTA provision will permit DEC to pursue coal blending as it makes economic sense to do so from a fuel procurement perspective, without the December 31, 2013 time limitation or other undue influence of rate recovery concerns.

Furthermore, in supplemental testimony supporting the Supplemental Stipulation, Applicants witness Weintraub testified that due to the procedural posture of the Applicants' merger application with the FERC, the close of the merger did not occur January 1, 2012, as the

Applicants had expected. Instead, according to Weintraub, the closing will occur in June or July 2012, assuming all regulatory approvals would be received in a timely manner. As a result, neither PEC nor DEC will have realized any capital CTA merger savings at the time they file their 2012 rate cases. In recognition of this changed circumstance the Applicants and the Public Staff have agreed that Paragraph No. 12 of the Stipulation should be revised as shown below in Paragraphs A(2) and (3). Public Staff witness Hoard testified that an extension of the December 31, 2013 deadline will provide each utility with a reasonable opportunity to pursue recovery in a general rate proceeding of their investments in capital CTA that are incurred within three years from the close of the merger. In addition, Applicants witness Weintraub testified that as further consideration for the Public Staff agreeing to these modifications PEC and DEC have agreed to waive their right to seek recovery of merger-related employee severance costs.

In regard to the aforementioned capital CTA, the Applicants and the Public Staff have now agreed in the Supplemental Stipulation, Section III, that the provisions in Paragraph No. 12 of the Stipulation relating to capital CTA are superseded by the following:

> A(2) Except as provided in Paragraph (3) below, DEC and PEC may seek to recover in their respective North Carolina retail rates, through depreciation or amortization, and inclusion in rate base, as appropriate and in accordance with normal ratemaking practices, their respective shares of capital costs associated with system integration projects and with the adoption of best practices, including information technology, provided that such costs are incurred no later than three years from the close of the Merger. Only the net depreciated costs of the system integration projects at the time the request is made may be included, and no request for deferral of any costs may be made.
>
> (3) Because the decline in the price of natural gas is likely to result in DEC taking delivery of fewer tons of coal at its Allen, Belews Creek, and Marshall coal-fired plants than assumed in the Fuel Synergies study filed as Exhibit 5 to the Merger application, the limitation in Paragraph A(2) above shall not apply to the capital costs associated with post-merger coal blending, and DEC may request recovery of such incurred capital costs, including information technology to the extent directly related to coal blending, in any general rate cases following the closing of the merger, in accordance with normal ratemaking practices, and subject to DEC showing that the eligible capital costs were reasonable and were prudently incurred. Only the net depreciated costs of the coal-blending equipment at the time the request is made may be included, and no request for deferral for any costs may be made.

As provided in Paragraph No. 12 of the Stipulation, with regard to merger-related severance costs, the Public Staff had opposed the inclusion of severance costs in cost of service for retail ratemaking purposes. Under the provisions of the Stipulation, DEC and PEC would have had the right to request recovery of these costs through amortization in the first application for a general rate case filed after the close of the merger and prior to December 31, 2013, upon a showing that these costs resulted in salary expense savings greater than the costs during the test period. The Public Staff would have had the right to oppose such recovery. However, as previously mentioned, the Applicants and the Public Staff have now agreed in the Supplemental Stipulation, Section III, that the provisions in Paragraph No. 12 of the Stipulation relating to merger-related severance costs are superseded by the following:

> A(1) DEC and PEC shall not request recovery in North Carolina retail rates of any of their allocable shares of the $226 million total post-merger combined company's estimated merger-related severance costs.

Regulatory Condition No. 5.14 provides that any acquisition adjustment that results from the merger shall be excluded from DEC's and PEC's utility accounts and treated for regulatory accounting, reporting, and ratemaking purposes in a manner such that it does not affect DEC's or PEC's North Carolina retail electric rates and charges.

Further, Regulatory Condition No. 5.15 provides that if the merger is not consummated then neither the cost nor the receipt of any termination payment between Duke and Progress shall be allocated to DEC or PEC or recorded on their books, and that neither DEC's nor PEC's North Carolina retail ratepayers will otherwise bear any direct expenses or costs associated with a failed merger.

No objections were made in the parties' briefs or proposed orders with respect to these particular provisions of the Stipulation and Regulatory Conditions, except for the following general exceptions. In particular, in its post-hearing Brief the Commercial Group simply observed that the Stipulation cites in Paragraph No. 12 a disagreement on future recovery of CTA and it reminded the Commission that it should closely watch/monitor CTA that may arise in future proceedings. Also, during the hearings some parties generally expressed concern with the possibility that DEC and PEC would be allowed to request recovery of merger-related severance costs, but those concerns were not addressed in post-hearing briefs or proposed orders. Furthermore, because PEC and DEC have now agreed in the Supplemental Stipulation to waive their right to seek recovery of merger-related employee severance costs that issue is moot.

In their comments filed on June 18, 2012, EDF, et al., expressed concern regarding the terms of the Supplemental Stipulation that remove the time limit for DEC's recovery of capital costs associated with coal blending. EDF, et al., asserted that removal of the time limit facilitates the increased use of coal blending, which could result in more and dirtier coal being burned and greater emissions from DEC's coal plants. In addition, EDF, et al., noted that it had proposed several conditions to address these concerns in their post-hearing Brief.

In the Applicants' reply comments filed on June 19, 2012, the Applicants noted that EDF, et al., raised the issue of increased coal burning and emissions during the evidentiary hearing in September 2011. The Applicants stated that this issue was addressed by Applicants witness Williams in testimony explaining that DEC and PEC will continue to be subject to compliance with the Clean Smokestacks Act and other emissions laws and regulations. Further, the Applicants noted that this provision of the Supplemental Stipulation was agreed upon because of the likelihood that low natural gas prices will incent DEC to burn more natural gas and less coal.

The Commission is not persuaded that removal of the time limit for the recovery DEC's capital costs associated with coal blending will result in increased emissions. Further, both DEC and PEC have a history of compliance with environmental regulations and will be required to continue their compliance after the merger. Therefore, the Commission is not persuaded that the proposed additional conditions recommended by EDF, et al., are reasonable or appropriate.

The Commission, therefore, finds and concludes that the provisions of the Stipulation, Regulatory Conditions, and the Supplemental Stipulation will effectively protect DEC's and PEC's retail ratepayers as much as reasonably possible from paying direct merger costs, capital costs, and other merger-related cost increases that could impact DEC's and PEC's North Carolina cost of service for retail ratemaking purposes.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence supporting this finding of fact is contained in the Stipulation, Regulatory Conditions, Code of Conduct, testimony of Applicants witnesses and Public Staff witnesses in support thereof, testimony of City of Orangeburg witness Bagwell, and the City of Orangeburg's Statement of Position and post-hearing Brief.

Regulatory Condition Nos. 3.1 through 3.11, 4.1 through 4.10, 5.3, and 5.11 provide the protections listed in this finding of fact as well as Paragraph Nos. 6 and 10 of the JDA. These protections include risks related to agreements and transactions between and among DEC, PEC, and their affiliates, including the JDA; financing transactions involving Duke, DEC, or PEC, and any other affiliate; the ownership, use, and disposition of assets by DEC or PEC; participation in the wholesale market by DEC or PEC; and filings with federal regulatory agencies. With the exception of Regulatory Condition Nos. 3.6, 3.7(c), 3.9(a), 3.9(b), and 3.9(c) and parallel provisions to the JDA contested by Orangeburg discussed below, no party has offered evidence contesting these provisions of the Stipulation, the Regulatory Conditions (addressing issues such as joint planning, coordination, and generation dispatch), the Code of Conduct or the testimony of the witnesses in support thereof. To the extent not contested by Orangeburg, the Commission determines that the uncontested and uncontradicted evidence is sufficient to support this finding of fact and need not be repeated here.

Orangeburg, through the testimony of its witness and in its post-hearing filings, objects to a number of the regulatory conditions in the Stipulation and in the structure of the JDA on the theory that they violate the federal preemption doctrine, the Supremacy and Commerce Clauses of the United States Constitution, and the public interest. Specifically, Orangeburg objects to proposed Regulatory Conditions 3.6, 3.7(e), 3.9(a), 3.9(b) and 3.9(c).

Orangeburg argues that these regulatory conditions would require DEC and PEC to submit proposed wholesale contracts for Commission review, purport to grant the Commission the authority to reallocate and reassign the revenues and costs of DEC's and PEC's wholesale costs for purposes of retail ratemaking and the authority to determine favored and disfavored wholesale native load customers and wholesale non-native load customers respectively, and bar the utilities from raising federal preemption arguments in opposition to Commission regulatory action.

Orangeburg argues that the JDA is intended to work in concert with the regulatory conditions. Orangeburg objects to the division of DEC's and PEC's customers into three categories, with customers like Orangeburg, a non-native load wholesale customer, placed in the category to which the highest cost energy dispatched under the JDA is allocated. Orangeburg argues that the JDA therefore works to create an undue preference in favor of native load customers and undue disadvantage to non-native load customers or potential customers like Orangeburg.

The Commission, the North Carolina appellate courts and FERC have been confronted by Orangeburg's arguments or by similar arguments by others on previous occasions. This history is useful in responding to Orangeburg's arguments here. The regulatory conditions at issue and the principles underlying them repeated in the framework of the JDA have been in place for many years. These regulatory conditions, designed to reserve to North Carolina native load retail customers and to similarly situated wholesale customers the cost of power from the plants they have paid for over the years, were initially approved by the Commission in past merger orders, such as the Duke-Cinergy order in 2006 and the CP&L-Progress order in 2000.

The regulatory condition requiring PEC to submit proposed wholesale contracts for review and the Commission's rulings on the scope and interpretation of that requirement were challenged in the North Carolina appellate courts. Ultimately, the North Carolina Supreme Court upheld the Commission's imposition of that requirement and rejected challenges made on federal preemption, Supremacy and Commerce Clause grounds. State ex rel. Utilities Com'n v. Carolina Power & Light Co. 359 N.C. 516, 614 S.E. 2d 281 (2005).

> [W]e hold that federal law does not preempt NCUC's authority to conduct a pre-sale review of a utility's proposed grant of native load priority to a wholesale customer that will be supplied from the same generating plants as retail customers. The review authority that NCUC possesses is necessary to enable it to fulfill its obligations under the North Carolina Public Utilities Act by ensuring that a regulated public utility has sufficient generating resources to provide reliable and adequate service to its captive retail ratepayers.

Id. at 529, 614 S.E. 2d at 290.

The Commission and the North Carolina appellate courts confronted similar challenges in 2008. DEC and Orangeburg had entered into a wholesale contract under which DEC agreed to provide Orangeburg's wholesale power needs at prices based on DEC's fully distributed costs, or costs determined on the same basis as DEC's native load retail customers. In accordance with regulatory conditions, DEC filed the contract with the Commission for review and requested a ruling that in future rate proceedings for retail customers, DEC's costs under the Orangeburg contract would be recognized at the contracted for fully distributed costs rather than higher incremental costs. Docket No. E-7, Sub 858. Rejecting arguments that the Commission should decline to provide guidance as to what its future ruling would be, the Commission informed the parties that its future ruling likely would recognize the costs under the DEC/Orangeburg contract at the incremental cost level. The Commission reasoned that this allocation of costs would provide the protection to North Carolina retail customers that the principles underlying the regulatory conditions being challenged in the present merger docket were designed to provide.

As subsequently noted by the North Carolina Court of Appeals, upon receiving this order, Orangeburg exercised its rights under the contract to terminate and entered into a substitute long-term contract with South Carolina Electric and Gas Company (SCE&G). In re Duke Energy Carolinas, 702 S.E. 2d 240 (NC App 16 Nov. 2010), No. COA09-1273, slip op. p. 5. Nevertheless, Orangeburg appealed the Commission's order to the North Carolina appellate courts[1]. The North Carolina Court of Appeals rejected Orangeburg's challenge to the Commission's order on the grounds of mootness. Id. p. 8. The Court determined that Orangeburg's exercise of its right to terminate rendered its appeal moot. The Court also noted that Orangeburg had failed to show that avenues to challenge the Commission's order in other jurisdictions were unavailable or that Orangeburg had unsuccessfully availed itself of those options. Id. p. 10. The North Carolina Supreme Court rejected Orangeburg's request that it review the opinion of the Court of Appeals. 709 S.E. 2d 364 (N.C. 7 June, 2011) No. 537 P 10.

In addition to appealing the Commission's order to the North Carolina appellate courts, in 2009 Orangeburg filed for declaratory relief before FERC in Docket No. EL09-63-000 challenging the Commission's alleged preference on behalf of North Carolina retail ratepayers. As of this date three years later, FERC has not taken up Orangeburg's complaint in the declaratory relief docket.

The regulatory conditions at issue in this docket repeat and refine the same regulatory conditions that were first imposed years ago and that have survived the challenges discussed above. The Duke/Progress merger at issue here requires FERC approval, as does the JDA. Orangeburg raises the same argument before FERC in the merger-related dockets as it raises before the Commission. See Duke Energy Corp. & Progress Energy, Inc., 137 FERC ¶ 61,209. The primary argument underlying Orangeburg's challenges before FERC is that the North Carolina Commission is acting as gatekeeper to DEC's and PEC's wholesale sales and will continue to do so under the proposed regulatory conditions. In both the FERC merger and JDA dockets, Orangeburg relies heavily on cases interpreting the filed rate doctrine and holding that FERC's jurisdiction over wholesale power transactions is exclusive, thus preempting this Commission's actions establishing a preference for North Carolina retail customers. Were Orangeburg correct in its repeatedly made arguments that the Commission is intruding upon FERC's exclusive jurisdiction, FERC would be expected to agree with them.

However, FERC has declined to provide Orangeburg relief in the merger docket, noting that North Carolina regulatory conditions have been in place for many years, are not new, and consequently Orangeburg has failed to establish the appropriate nexus between the North Carolina regulatory conditions and the proposed Duke/Progress merger. Order on Disposition of Jurisdictional Facilities and Merger, Sept. 30, 2011, Docket No. EC-11-60-000, 136 FERC ¶ 61,245. Most recently, in its June 8, 2012 Order Accepting Revised Compliance Filing, as Modified, and Power Sales Agreements, FERC states:

[1] Although regulatory conditions were in place at that time preventing DEC from challenging the Commission's order on appeal, similar to the conditions Orangeburg challenges here, the conditions did not prohibit Orangeburg from appealing.

> The Commission rejects City of Orangeburg's arguments pertaining to the state regulatory conditions for the same reasons that we did so in the Merger Order – namely, that City of Orangeburg has "failed to demonstrate that the alleged harms to competition stem from the Proposed Transaction." The alleged harms that City of Orangeburg complains of are based on existing state regulatory policies, which are currently in place and will continue in effect regardless of whether the Proposed Transaction goes forward. Consequently, we will not address those arguments here.

Docket No. EC11-60-004, 139 FERC ¶ 61,194.

In the FERC JDA docket FERC likewise has rejected Orangeburg's request to modify the JDA to remove the preference for native load retail and wholesale customers. After making limited modifications to the JDA by striking provisions of section 3.2(c) that pertain to retail ratemaking on the grounds that these provisions are inappropriate to include in a wholesale agreement before FERC and concluding that the JDA's allocation of different cost levels for new and existing non-native load customers are discriminatory, FERC concluded "we do not object to the JDA's allocation of the lowest cost power to native load customers."

In the present dockets, in the context outlined above, the Commission rejects Orangeburg's challenges to the regulatory conditions and to the JDA and approves the challenged paragraphs of the joint stipulation and the JDA (to the extent not modified by FERC). At present, Orangeburg has a long-term wholesale power supply agreement with SCE&G lasting through 2022 or 2023. For reasons satisfactory to itself, Orangeburg exercised its right to terminate the proposed DEC/Orangeburg contract in 2009. The Commission can take no action in the present dockets before it that may provide Orangeburg relief for regulatory conditions or determinations that allegedly harmed Orangeburg in the past. There is no evidence of record that Orangeburg has requested, nor that DEC has offered, a replacement wholesale contract. In its November 23, 2011, post hearing Brief Orangeburg refers to itself only as "a potential wholesale power customer." Indeed, under the JDA, Orangeburg would only fall into the category of non-native load wholesale customers. There is no evidence of record that shows that Orangeburg either is representing or could represent other similarly situated non-native load wholesale customers. Presently, only two other non-native load wholesale customers have contracts with the merger Applicants. When these two contracts expire, the "existing non-native load [contracts] jobs" will disappear. Applicants June 12 Revisions to Joint Dispatch Agreement.

For the most part the challenged regulatory conditions constrain DEC and PEC, yet in the negotiation process leading to the Stipulation the companies have acquiesced in them. Further, no party other than Orangeburg questioned the enforceability or effectiveness of these Regulatory Conditions.

The Commission determines that Orangeburg lacks standing at this time and in these dockets to raise these issues and alternatively that Orangeburg's arguments as they contemplate potential future harm are not ripe for consideration. By the time Orangeburg is back in the wholesale market, DEC and PEC may be fully integrated into a single electric power supplier and the JDA may have been terminated. As it has with respect to other wholesale customers, the Commission in spite of its earlier advisory ruling may reassess Orangeburg's status as a wholesale native local customer based on conditions and circumstances existing at the time. Orangeburg may be unwilling or unable to negotiate a wholesale power agreement with DEC or PEC or the merged company for reasons unrelated to its status as a non-native load wholesale customer.

FERC, or the courts to which FERC orders may be appealed, have these issues involving the scope of federal authority before them, and these tribunals are best positioned to address and resolve them at this time. To the extent the issues are presently judicable, the Commission defers to these tribunals.

To date, the North Carolina appellate courts have rejected every challenge to the regulatory conditions establishing the preference to which Orangeburg objects. Furthermore, FERC, with the exception of its limited modification of the JDA, has also rejected Orangeburg's challenge to the Commission's actions. Significantly, despite Orangeburg's contentions that the Commission's actions infringe on FERC jurisdiction, FERC rejected Orangeburg's substantive arguments that the JDA is unduly prejudicial to customers like Orangeburg. Moreover, FERC expressly declined to address Orangeburg's arguments on the regulatory conditions. In FERC's view, the conditions and any alleged harm they might cause exist because of existing state policy and do not arise out of or result from the proposed merger. Accordingly, FERC deliberately made no comment or finding with respect to state regulatory policy. Consequently, the Commission reaffirms its prior rulings, accepts the regulatory conditions as agreed to by the Applicants, including those challenged by Orangeburg, and rejects Orangeburg's challenges to the JDA, which FERC now has approved over Orangeburg's objections.

The Commission concludes that nothing in either the requirements imposed by the FERC in its orders issued before and after the revised filings concerning the Applicants' merger or in changes in federal energy law in this area since 2005 creates a need to add further safeguards or language to the Regulatory Conditions, with the one exception noted below. This conclusion is based largely on the breadth of the anti-preemption Regulatory Conditions and the inclusion of savings clauses in EPACT 2005 that expressly preserve state jurisdiction. However, the one exception is the FERC's recent effort to expand its authority over transmission planning and cost allocations in FERC Order No. 1000. In response to this development, the advance notice provision of Regulatory Condition No. 3.10(c) has been amended to explicitly state that advance notice is required prior to any filing made with the FERC that has the potential to reduce the Commission's jurisdiction with respect to transmission planning or any other aspect of the Commission's planning authority.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence supporting this finding of fact is contained in the Stipulation, Regulatory Conditions, Supplemental Stipulation, as amended, the information submitted by the Applicants in response to the Commission's Post-hearing Order, the testimony of Applicants witnesses Kalt and Weintraub, the testimony of Public Staff witnesses Morey and Hoard, the testimony of EDF, et al., witness Hahn, the June 22, 2011 amendments to the JDA filed by DEC and PEC, the FERC JDA Order; and the Public Staff's June 13, 2012 comments.

The primary purpose of Section IV of the Regulatory Conditions is to ensure that DEC's and PEC's respective retail customers receive adequate benefits from the JDA, and that joint dispatch costs and the sharing of cost savings can be appropriately audited.

In addition, Regulatory Condition No. 4.5 requires that all joint dispatch and other activities pursuant to the proposed JDA or successor document be performed in such a manner as to (a) ensure the reliable fulfillment of DEC's and PEC's respective service obligations to their retail customers, (b) fulfill each utility's obligation to serve its own retail customers with its lowest cost generation; and (c) minimize the total costs incurred by DEC and PEC to fulfill their respective obligations to their retail customers. With respect to the treatment of costs and savings, Regulatory Condition No. 4.6 provides that DEC's and PEC's respective fuel and fuel-related costs and non-fuel O&M costs, and the treatment of savings for retail ratemaking purposes, shall be calculated as provided in the JDA, unless explicitly changed by order of the Commission. DEC and PEC are required by Regulatory Condition No. 4.7 to keep records related to the JDA or any successor document as prescribed by the Commission and in such detail as may be necessary to enable the Commission and the Public Staff to audit both the actual joint dispatch costs and the sharing of cost savings. To protect against transactions pursuant to the JDA that produce negative margins, Regulatory Condition No. 4.8 requires that such recordkeeping be in sufficient detail to enable the Commission and the Public Staff to audit the circumstances that cause any negative margin on a non-native load sale or a negative transfer payment made pursuant to Section 7.5(a)(ii) of the JDA.

In response to questions by the Commission, DEC and PEC agreed to file with the Commission the information and notifications required by Paragraph No. 11 of the Stipulation, under seal if the information is deemed confidential.

Further, the Commission's Post-Hearing Order, Question No. 15, inquired when DEC and PEC would provide the Commission with an integrated resource plan that reflects joint planning and operations, including generation resources built to serve both of them, or delayed plans for such additions. The Applicants responded that Section 3.2 (b) of the JDA provides that if they desire to conduct joint planning and the joint development of generation or transmission, they would have to amend the JDA or enter into a separate agreement and seek all required regulatory approvals. The response further stated that DEC and PEC plan to conduct some joint generation planning following the close of the merger and will be seeking all required regulatory approvals. In the near future, however, DEC and PEC will continue to file separate integrated resource plans until the integration of the operating companies or until required by order or law.

With respect to transmission planning, which was included as part of Question No. 15, the Applicants stated that DEC and PEC already engage in coordinated planning of their bulk transmission systems (230 kV and above) for major projects through the North Carolina Transmission Planning Collaborative, which includes NCEMC, NCEMPA, and NCMPA 1 in addition to DEC and PEC.

The Commission notes that Regulatory Condition No. 4.7 requires DEC and PEC to keep records related to the JDA or any successor document as prescribed by the Commission and in such detail as may be necessary to enable the Commission and the Public Staff to audit both the actual joint dispatch costs and the sharing of cost savings. The Stipulation further spells out certain requirements to ensure that the implementation of the JDA is done appropriately and can be monitored in real-time. The Applicants' agreement to file the required information with the Commission also will help ensure that joint dispatch costs and the sharing of cost savings can be appropriately audited.

Although some intervenors questioned the level of benefits to be produced by the JDA, no party challenged the related Regulatory Conditions with respect to whether they ensure that DEC's and PEC's retail ratepayers receive substantial benefits from the JDA and ensure that joint dispatch costs and the sharing of cost savings can be appropriately audited.

EDF, et al., witness Hahn testified that DEC and PEC should be required to modify the JDA to reflect a single balancing authority area (BAA). Witness Hahn stated that a single BAA, or "tight power pool," could achieve the maximum benefits of central dispatch. Applicants' witness Weintraub testified that witness Hahn appeared to believe that having three separate BAAs prohibits PEC and DEC from conducting joint dispatch as a combined system with combined generation and load as modeled by Compass Lexecon, and that Hahn was incorrect. Witness Weintraub stated that DEC and PEC will be able to conduct joint dispatch as a combined system regardless of whether there are three BAAs or one BAA, and that the Applicants will implement one unit commitment plan and conduct a single security constrained economic dispatch to serve the combined native loads of both DEC and PEC.

The Stipulation provides that to enable the Public Staff to monitor the implementation of the JDA, DEC and PEC will (1) provide, prior to the implementation of the JDA, a detailed description of the production cost model that will be used, including the algorithms, assumptions, and inputs by the model to simulate the production costs of DEC and PEC under the stand-alone utility case; (2) verify the accuracy of the production cost model in estimating stand-alone utility production costs by benchmarking the model against a recent historical period in which DEC and PEC dispatched their generation on a stand-alone basis; (3) notify the Public Staff at least quarterly when significant changes have been made to the algorithms, assumptions and inputs to the model and provide an explanation justifying those changes; and (4) provide the Public Staff with all the information needed to audit the model inputs and outputs as often as monthly until the utilities and the Public Staff have gained experience with the model, and at least quarterly thereafter.

The Applicants' March 26, 2012 revised mitigation plan established certain wholesale power sales in order to mitigate wholesale market power on an interim basis. As a result, the Supplemental Stipulation included provision A.(4), which states as follows:

> Interim Mitigation Sales shall be treated as a separate category of New Non-Native Load Sales and shall be deemed to have been satisfied by the highest energy costs assigned to New Non-Native Load Sales pursuant to JDA Section 7.2.

The June 8, 2012 FERC JDA Order required that two changes be made to the JDA. One of the changes is the removal of subsections (ii), (iii) and (iv) from Section 3.2(c). Section 3.2 of the JDA, as filed with the FERC, provided as follows:

(c) In addition to the foregoing, DEC and PEC have agreed, in previous proceedings before the NCUC (NCUC Docket E-7, Sub 795 and NCUC Docket E-2, Sub 884, respectively), to insert into any affiliate agreements such as this Agreement the following provisions:

(i) DEC's or PEC's participation in the agreement is voluntary, DEC or PEC is not obligated to take or provide services or make any purchases or sales pursuant to the agreement, and DEC or PEC may elect to discontinue its participation in the agreement at its election after giving any required notice;

(ii) Neither DEC nor PEC may make or incur a charge under this Agreement except in accordance with North Carolina law and the rules, regulations and orders of the NCUC promulgated thereunder;

(iii) Neither DEC nor PEC may seek to reflect in its North Carolina retail rates (i) any costs incurred under this Agreement exceeding the amount allowed by the NCUC or (ii) any revenue level earned under the Agreement other than the amount imputed by the NCUC; and

(iv) Neither DEC nor PEC will assert in any forum that the NCUC's authority to assign, allocate, make pro forma adjustments to or disallow revenues or costs for retail ratemaking and regulatory accounting and reporting purposes is preempted and DEC and PEC will bear the full risk of any preemptive effects of federal law with respect to this Agreement.

The reason stated by the FERC for removing these subsections is that they pertain to retail ratemaking and, therefore, are not appropriate in a FERC-jurisdictional wholesale agreement. In the JDA Order, the FERC stated that beyond requiring removal of these provisions the FERC offered no view on the North Carolina Utilities Commission's authority to impose or apply such requirements.

The Public Staff's June 13, 2012 comments stated that the provisions of Section 3.2(c) were first proposed in 2000 by the Public Staff, in Docket No. E-2, Sub 753, to protect the Commission's jurisdiction from preemption by the Securities and Exchange Commission when PEC applied to the Commission for approval to create a registered holding company under the Public Utility Holding Company Act of 1935 as part of PEC's acquisition of Florida Progress Corporation. According to the Public Staff, these conditions were included in the original JDA to obtain the maximum amount of protection against preemption that the Public Staff could devise. In its comments filed on June 13, 2012, the Public Staff proposed the following three amendments to the Regulatory Conditions and one new Regulatory Condition to address any loss of protection that might result from the FERC's elimination of subsections 3.2(c)(ii), (iii) and (iv) from the JDA.

(1) The definition of Affiliate Contract is amended to state:

> **Affiliate Contract:** Any contract or agreement (a) between and among any of the Affiliates if such contracts are reasonably likely to have an Effect on DEC's or PEC's Rates or Service, or (b) to which both DEC and any Affiliate are parties or PEC and any Affiliate are parties, including contracts with proposed Affiliates. Such contracts and agreements include, but are not limited to, service, operating, interchange, pooling, ~~and~~ wholesale power sales agreements and agreements involving financings and asset transfers and sales, and the Joint Dispatch Agreement.

(2) Condition 3.1 is amended by adding a new subsection (e):

> (e) In the event the FERC or any other federal regulatory agency requires modification of a proposed Affiliate Contract to omit any of the provisions of Condition 3.1(b) as a condition of acceptance or approval by that agency, DEC and PEC shall remain bound by those provisions for state regulatory purposes.

(3) The introductory paragraph for Section IV is amended by adding the following sentence at the end:

> The Regulatory Conditions set forth in Section III and the Regulatory Conditions in Section V to the extent they are relevant to Affiliate Contracts also apply to the JDA.

(4) A new Condition 4.12 is added at the end of Section IV:

> 4.12 Hold Harmless Commitment. DEC and PEC shall take all actions as may be reasonably appropriate and necessary to hold North Carolina retail ratepayers harmless from any adverse rate impacts related to the JDA, including any trapped costs resulting from actions taken or required by the FERC with respect to the JDA.

In his further supplemental testimony filed on June 13, 2012, Applicants witness Weintraub stated that the Applicants support these changes to the Regulatory Conditions.

The Commission finds that the FERC's elimination of subsections 3.2(c)(ii), (iii) and (iv) from the JDA is not a material detriment to the preemption protections afforded by the Stipulation, for three reasons. First, the language of Regulatory Condition No. 3.1(b) is substantially similar to that of subsections 3.2(c)(ii), (iii) and (iv) of the JDA. Second, the proposed amendments to the Regulatory Conditions clarify and strengthen the application of Regulatory Condition No. 3.1(b) to the JDA. Third, new Regulatory Condition No. 4.12 is a stronger hold harmless condition than those previously offered by the Applicants. Therefore, the Commission concludes that Regulatory Condition No. 3.1(b), the proposed amendments to the Regulatory Conditions and new Regulatory Condition No. 4.12 adequately remedy any loss of protection that might result from the FERC's elimination of subsections 3.2(c)(ii), (iii) and (iv) from the JDA.

The second change to the JDA required by the FERC is the removal of the distinction between existing non-native load customers and new non-native load customers. The FERC stated that this disparate treatment of the two customer classes had not been justified by the Applicants. However, the FERC accepted the JDA's reservation of the lowest cost power for DEC's and PEC's native load customers. In his further supplemental testimony, Applicants witness Weintraub testified that none of the modifications required by FERC alter the ability of the Applicants to achieve the fuel savings described in previous testimony or otherwise impair any of the benefits of the JDA to North Carolina customers.

The Commission concludes that the proposed amendments to the Regulatory Conditions and new Regulatory Condition No. 4.12, in conjunction with the other provisions of the Stipulation, will protect as much as reasonably possible the Commission's authority to ensure least-cost service and reasonable retail rates.

As stated earlier, the FERC’s JDA Order found that the Applicants had not justified the proposed disparate treatment of existing non-native load customers and new non-native load customers, and required that the two groups be merged into one. The Public Staff stated in its June 13, 2012 comments that the merging of these two classes of customers should have no impact on the savings guarantee for retail customers, because the existing non-native load customer class is very small and native load will be allocated only the costs that remain after the highest costs are allocated to non-native load sales. Similarly, the further supplemental testimony of Applicants witness Weintraub stated that:

> Merging existing non-native load sales and new non-native load sales into one class for purposes of the JDA has no impact on the $650 million savings guarantee, because this revision only deals with non-native load transactions and does not impact native load. Furthermore, the class of existing non-native load sales is small, only two contracts. ... Additionally, merging these two types of sales will not change the total costs allocated to non-native load sales for purposes of the JDA. The resources allocated to native load will only be those that remain after the highest cost resources have been allocated to non-native load sales.

In response to the FERC’s June 8, 2012 JDA Order, the Public Staff recommended that Section I.A.(4) of the Supplemental Stipulation be revised to accommodate the FERC’s requirement that the distinction between existing non-native load customers and new non-native load customers be removed as follows:

> Interim Mitigation Sales shall be treated as a separate category of Non-Native Load Sales and shall be deemed to have been satisfied by the highest energy costs assigned to Non-Native Load Sales pursuant to JDA Section 7.2.

Similarly, the Public Staff stated that to ensure that the mechanism approved in DEC's recent general rate cases to flow an appropriate share of the net revenues from DEC's short-term wholesale sales to its retail ratepayers through an annual rider is not adversely affected, the following new condition should be approved:

> Bulk Power Marketing Sales, as defined in DEC's BPM Net Revenues and Non-Firm Point-to-Point Transmission Revenues Adjustment Rider (NC), shall be treated as a separate category of Non-Native Load Sales and shall be deemed to have been satisfied by the next highest energy costs, after the assignment of energy costs to Interim Mitigation Sales.

In its June 18, 2012 comments, Orangeburg stated that:

> The additional and modified conditions recommended by the Public Staff to the proposals by the Applicants to comply with FERC's June 8 Orders should be rejected by this Commission because they would further unlawfully intrude upon and interfere with FERC's jurisdiction.

The Commission finds that the Public Staff's recommendations are appropriate to the extent that their application is limited to the calculation of costs and savings that are allocated to retail customers. Therefore, the Commission accepts the above revision to Section I.A.(4) of the Supplemental Stipulation and the new condition.

The FERC JDA Order stated that the Applicants had not shown whether their existing joint ownership agreements establish whether, and if so, how, co-owners of jointly-owned facilities will share in cost savings resulting from joint economic dispatch as contemplated under the JDA. The FERC directed the Applicants to submit such an explanation in a compliance filing within 60 days of the issuance of the JDA Order. The Public Staff stated in its June 13, 2012 comments that it believes that neither DEC nor PEC has any rights to the output associated with its co-owners' shares of the jointly-owned facilities. Because the JDA is an agreement between DEC and PEC and involves only the power resources of DEC and PEC, the co-owners' shares of the output of jointly-owned facilities are not, and should not be, subject to the JDA, according to the Public Staff. As a result, the co-owners' portions of the jointly-owned facilities will not be included in joint dispatch pursuant to the JDA, and the co-owners should not share in any of the JDA savings. Similarly, the Applicants' witness Weintraub stated in his June 13, 2012 further supplemental testimony that:

> Because DEC and PEC have no rights to the portions of the output of the units to which the co-owners are entitled, such output is not subject to the JDA, and the co-owners [sic] rights are not affected by the JDA.

Based on the testimony and comments cited above, as well as the FERC JDA Order, the Commission finds and concludes that the JDA, along with the relevant provisions of the Stipulation, Regulatory Conditions and Supplemental Stipulation, as amended, will ensure that North Carolina's retail customers receive adequate benefits from the JDA, that they are protected as much as reasonably possible from potential risks associated with the FERC's jurisdiction over the JDA, and that the Applicants and the Public Staff have established a workable framework for auditing the costs and benefits of the JDA. The Commission also finds and concludes that the monitoring and implementation of the JDA are central to ensuring that customers realize adequate benefits from the merger. Therefore, the Commission concludes that it is appropriate to amend the Stipulation to require DEC and PEC to file with the Commission the information that would otherwise be provided only to the Public Staff relative to the production cost models used to implement the JDA.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

The evidence supporting this finding of fact is contained in the Stipulation, Regulatory Conditions and Code of Conduct and the direct testimony of Public Staff witness Hoard.

Regulatory Condition No. 5.1 provides that in accordance with North Carolina law the Commission and the Public Staff will continue to have access to the books and records of DEC, PEC, Duke, other affiliates, and the nonpublic utility operations of DEC and PEC.

In addition, the Stipulation and Regulatory Conditions include provisions that address risks and concerns related to cost allocation and ratemaking arising from the merger, including ensuring that the costs incurred by DEC and PEC are properly incurred, accounted for, and directly charged, directly assigned, or allocated to their respective North Carolina retail operations and that only costs that produce benefits for their respective retail ratepayers are included in DEC’s and PEC’s North Carolina cost of service for retail ratemaking purposes.

In this regard, Paragraph No. 8 of the Stipulation provides that for purposes of distributing the costs of services provided between and among affiliates PEC will continue to use direct charging, and all PEC employees will continue to use positive time reporting; and DEC will increase the amount of such costs that are directly charged and will complete the transition to direct charging and positive time reporting within two years following the close of the merger. This paragraph further provides that DEC will file semi-annual reports with the Commission detailing its progress in implementing these practices, with the first report due six months after the close of the merger.

Public Staff witness Hoard testified that affiliated transactions rules, such as those set forth in DEC’s and PEC’s current respective Regulatory Conditions and Codes of Conduct, are designed to: (1) fairly allocate the cost of common goods and services among affiliates; (2) protect ratepayers from overcharges by non-regulated affiliates; and (3) prevent cross-subsidization of non-regulated affiliates by their utility affiliates. Hoard further testified that as a part of the Stipulation the Applicants, DEC, PEC, and the Public Staff have agreed on the affiliated transaction pricing rules contained in the Code of Conduct.

Further, Public Staff witness Hoard explained that the caps that had been previously imposed on the amount of transactions that could occur between regulated utilities at fully distributed costs created a barrier that served to discourage utility affiliates from keeping some shared utility functions within one or more of the utilities and incented the utilities to transfer core utility operating functions to a service company. According to Hoard, the removal of the cap led to the Applicants agreeing to keep core utility functions within DEC and PEC, instead of placing those functions in a service company.

Regulatory Condition No. 5.2 establishes the principles that will govern the prices at which goods and services are exchanged between and among DEC, PEC, and their affiliates, subject to additional provisions set forth in the Code of Conduct. While providing for an exception with respect to transactions between DEC and PEC pursuant to filed and approved service agreements and lists of services, this condition requires DEC and PEC to seek out and buy all goods and services from the lowest cost qualified provider of comparable goods and services. Further, DEC and PEC shall have the burden of proving that any and all goods and services procured from any affiliate have been procured on terms and conditions comparable to the most favorable terms and conditions reasonably available in the relevant market, which shall include a showing that comparable goods or services could not have been procured at a lower price from qualified non-affiliate sources or that neither DEC nor PEC could have provided the services or goods for itself on the same basis at a lower cost.

To the extent DEC and PEC are allowed to provide goods and services to non-utility affiliates, they will have the burden of proving that all goods and services either of them provide to any affiliate other than one of their regulated utility affiliates have been provided on terms and conditions that are comparable to the most favorable terms and conditions reasonably available in the market, which shall include a showing that such goods or services have been provided at the higher of cost or market price.

To establish that they have met the foregoing requirements, DEC and PEC, no less than every four years, will be required to perform comprehensive, non-solicitation based assessments at a functional level of the market competitiveness of the costs for goods and services they receive from, or provide to, a utility affiliate, DEBS, PESC, another non-utility affiliate, and a nonpublic utility operation.

Further, to the extent the Commission approves the procurement or provision of goods and services between and among DEC, PEC, and the utility affiliates, those goods and services may be provided at the supplier's fully distributed cost. In the Public Staff's September 15, 2011 filing, the Public Staff provided a corrected version of the stipulated Regulatory Conditions and Code of Conduct to mainly correct typographical and formatting errors discovered subsequent to the September 2, 2011 Stipulation filing. However, there was a substantive revision to the definition of "fully distributed cost." According to the Public Staff, a modification had been agreed to prior to the filing of the September 2, 2011 Stipulation, but it had been inadvertently omitted. As a result, the Code of Conduct definition for "fully distributed cost" was corrected by the Public Staff in its September 15, 2011 filing to reflect that the stipulated definition, as corrected, should provide that "for each good and service supplied by DEC and PEC to each other, the return on common equity utilized in determining the appropriate cost of capital shall not exceed the lower of the returns on common equity authorized by the Commission in DEC's and PEC's most recent general rate case proceedings."

Under Regulatory Condition No. 5.4, DEC and PEC will be required to file, pursuant to G.S. 62-153, final proposed service agreements that authorize the provision and receipt of non-power goods or services between and among DEC, PEC, their affiliates or non-public utility operations, the list(s) of goods and services that DEC and PEC each intend to take from DEBS and PESC, the list(s) of goods and services DEC and PEC intend to take from each other and their regulated utility affiliates, and the basis for the determination of such list(s) and the elections of such services. All such lists that involve the payment of fees or other compensation by DEC or PEC 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. DEC and PEC are allowed to take goods and services from an affiliate only in accordance with the filed service agreements and approved list(s) of services and notice is required prior to any changes being made to the service agreements or to the lists of services.

Regulatory Condition No. 5.5 provides that to the maximum extent practicable all costs of affiliate transactions shall be directly charged. When not practicable, such costs shall be assigned in proportion to the direct charges. If such costs are of a nature that direct charging and direct assignment are not practicable, they shall be allocated in accordance with Commission-approved allocation methods. Both DEC and PEC are required to keep on file with the Commission cost allocation manuals (CAMs) with respect to goods or services provided by DEC or PEC, any utility affiliate, DEBS or PESC, any other non-utility affiliate, Duke, any other affiliates, or any non-public utility operation to either DEC or PEC.

In addition, Regulatory Condition No. 5.5, Subsection (c) provides for an annual update of the CAMs and the filing of the revised CAMs with the Commission no later than March 31 of the year that the CAMs are to be in effect. DEC and PEC are required to review the appropriateness of the allocation bases every two years, and the results of such review must be filed with the Commission.

Regulatory Condition No. 5.9 provides that all of the services rendered by DEC and PEC to their affiliates and nonpublic utility operations and the services received by DEC or PEC from their affiliates and nonpublic utility operations pursuant to the filed service agreements, the costs and benefits assigned or allocated in connection with such services, and the determination or calculation of the bases and factors utilized to assign or allocate such costs and benefits, as well as DEC's and PEC's compliance with the Commission-approved Regulatory Conditions and Code of Conduct, shall remain subject to ongoing review by the Commission.

Regulatory Condition No. 5.10 provides that for the purposes of North Carolina retail accounting, reporting, and ratemaking, the Commission may, after appropriate notice and opportunity to be heard, issue orders relating to DEC's or PEC's cost of service as the Commission may determine are necessary to ensure that DEC's and PEC's operations and transactions with their affiliates and non-public utility operations are consistent with the Regulatory Conditions and Code of Conduct, and with any other applicable decisions of the Commission.

No objections were raised in the parties' briefs or proposed orders with respect to these particular provisions of the Stipulation, Regulatory Conditions and Code of Conduct.

The Commission, therefore, finds and concludes that the provisions of the Stipulation, Regulatory Conditions and Code of Conduct, as indicated above, will protect retail ratepayers as much as reasonably possible from potential risks related to cost allocation and ratemaking arising from the merger, including ensuring that the costs incurred by DEC and PEC are properly incurred, accounted for, and directly charged, directly assigned or allocated to their respective North Carolina retail operations and that only costs that produce benefits for their respective retail ratepayers are included in DEC's and PEC's North Carolina cost of service for retail ratemaking purposes.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

The evidence supporting this finding of fact is contained in the Stipulation, Regulatory Conditions and Code of Conduct.

The Stipulation and Regulatory Conditions impose certain auditing and reporting requirements with respect to affiliate transactions and cost of service. In particular, Regulatory Condition No. 5.7 would continue the current requirement that DEC and PEC shall each file annual reports of affiliated transactions with the Commission in a format to be prescribed by the Commission on or before May 30 of each year, for activity through December 31 of the preceding year. Such annual reports should be filed in Docket Nos. E-7, Sub 986A and E-2, Sub 998A. DEC, PEC, and other parties may propose changes to the required affiliated transaction reporting requirements and submit them to the Commission for approval, in Docket Nos. E-7, Sub 986B and E-2, Sub 998B.

Regulatory Condition No. 5.8 clarifies and expands the third-party independent audit report requirement that currently applies only to DEC. It divides the subject matter of each audit as follows:

(a) The first audit following the close of the merger, which is required to begin two years from the date of close, includes a determination as to whether DEC and PEC have adopted systems, policies, CAMs, and other processes to ensure compliance with all of the conditions related to affiliate dealings and the Code of Conduct and have operated in accordance with those conditions and the Code of Conduct.

(b) The second audit, which is required to begin two years from the date of the Commission's order on the independent auditor's final report on the first audit or, if no such order is issued, two years from the date of such final report, includes a determination as to whether DEC's and PEC's transactions, services, and other affiliate dealings pursuant to the regulated utility-to-regulated utility service agreement and any other utility to utility agreements are consistent with all of the conditions related to affiliate dealings and the Code of Conduct and whether DEC and PEC have operated in accordance with those conditions and the Code of Conduct.

(c) The third audit, which is required to begin two years from the date of the Commission's order on the independent auditor's final report on the second audit or, if no such order is issued, two years from the date of such final report, includes a determination as to whether DEC's and PEC's transactions, services, and other affiliate dealings pursuant to the service company utility service agreement and other affiliate transactions other than transactions undertaken pursuant to regulated utility-to-regulated utility service agreements are consistent with all of the conditions related to affiliate dealings and the Code of Conduct and whether DEC and PEC have operated in accordance with those conditions and the Code of Conduct.

(d) Thereafter, independent audits shall occur every two years from the date of the Commission's order on the immediately preceding auditor's final report or, if no such order is issued, two years from the date of such final report, with the subject matter of these audits alternating between the subject matters for the second and third independent audits. DEC or PEC may request a change in the frequency of the audit reports in future years, subject to approval by the Commission.

Regulatory Condition No. 5.12 provides that transactions between DEC or PEC and Duke, other affiliates, or other nonpublic utility operations, transactions between DEC and PEC, and other transactions between or among affiliates if such transactions are reasonably likely to have a significant effect on DEC's or PEC's rates or service, shall be reviewed at least biannually by Duke's internal auditors. Further, relevant workpapers relating to the internal audits must be provided to the Commission and the Public Staff. Likewise, if external audits are conducted, then their relevant workpapers must also be provided.

In addition, Regulatory Condition No. 5.13 provides that at such time as DEC, PEC, Duke, DEBS, or PESC receives notice from the FERC related to an audit of any affiliate of DEC or PEC, DEC or PEC is required to promptly file a notice with the Commission that such an audit will be commencing. Any initial report of the FERC's audit team shall be provided to the Public Staff, and any final report must be filed with the Commission in Docket Nos. E-7, Sub 986E and E-2, Sub 998E, respectively.

No objections were raised in the parties' briefs or proposed orders with respect to these particular provisions of the Stipulation, Regulatory Conditions and Code of Conduct.

The Commission, therefore, finds and concludes that the provisions of the Stipulation, Regulatory Conditions and Code of Conduct, as indicated above, will provide appropriate and effective auditing and reporting requirements with respect to affiliate transactions and cost of service, thereby ensuring that costs will be properly recorded and can be effectively audited by the Public Staff and the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

The evidence supporting this finding of fact is contained in the Stipulation and Regulatory Conditions.

Regulatory Condition No. 5.16 is intended to protect DEC's and PEC's North Carolina retail ratepayers from impacts of the merger on cost of service for ratemaking purposes. In particular, Regulatory Condition No. 5.16 ensures that DEC's and PEC's North Carolina retail ratepayers are held harmless from any cost assignment or allocation of costs resulting from agreements (a) between DEC and the Catawba Joint Owners; (b) between PEC and NCEMPA as joint owner; and (c) between either DEC or PEC and any of their wholesale customers. It further provides that to the extent commitments to DEC's or PEC's wholesale customers relating to the merger are made by or imposed upon DEC or PEC that affect the benefits of bulk power revenues, increase DEC's or PEC's North Carolina retail cost of service, or increase DEC's or PEC's North Carolina retail fuel costs under reasonable cost assignment and allocation practices, those effects shall not be recognized for North Carolina retail cost of service or ratemaking purposes. Finally, this Regulatory Condition also provides that to the extent that commitments are made by or imposed upon DEC, PEC, Duke, another affiliate, or a non-public utility operation relating to the merger, either through an offer, a settlement, or as a result of a regulatory order, the effects of which serve to increase the North Carolina retail cost of service or North Carolina retail fuel costs under reasonable cost allocation practices, the effects of these commitments shall not be recognized for North Carolina retail ratemaking purposes.

Regulatory Condition No. 5.17 provides that the assignment or allocation of costs to the North Carolina retail jurisdiction shall not be adversely affected as a result of the manner and amount of recovery of electric system costs from (a) the Catawba Joint Owners as a result of agreements between DEC and the Catawba Joint Owners or (b) the NCEMPA as a result of agreements between it and PEC.

In addition, Regulatory Condition No. 5.18 prohibits DEC, PEC, Duke, and their affiliates from asserting that any interested party cannot seek the inclusion in future rate proceedings of cost savings that may be realized as a result of any business combination transaction impacting DEC and PEC.

Further, of particular significance are the protections provided by Regulatory Condition No. 5.21, which protects DEC's and PEC's retail native load customers from all liabilities of Cinergy Corporation and its subsidiaries, including those incurred prior to and after Duke's acquisition of Cinergy Corporation in 2006. These liabilities include, but are not limited to, those associated with: (i) manufactured gas plant sites; (ii) asbestos claims; (iii) environmental compliance; (iv) pensions and other employee benefits; (v) decommissioning costs; and (vi) taxes. This condition also protects DEC's and PEC's retail ratepayers from all liabilities of Florida Progress Corporation and its subsidiaries, including those incurred prior to and after Progress's acquisition of Florida Progress Corporation in 2000. These liabilities include, but are not limited to, those associated with the following: (i) any outages at and repairs of Crystal River 3; (ii) manufactured gas plant sites; (iii) asbestos claims; (iv) environmental compliance; (v) pensions and other employee benefits; (vi) decommissioning costs; and (vii) taxes. Subsection (c) of Regulatory Condition 5.21 also provides that DEC's retail ratepayers shall be held harmless from all current and prospective liabilities of PEC, and PEC's retail ratepayers shall be held harmless from all current and prospective liabilities of DEC.

Finally, Regulatory Condition No. 5.22 is a blanket hold harmless commitment. It requires DEC, PEC, all other affiliates, and all of the non-public utility operations to take all such actions that may be reasonably necessary and appropriate to hold North Carolina retail ratepayers harmless from the effects of the merger, including rate increases or foregone opportunities for rate decreases, and other effects otherwise adversely impacting North Carolina retail ratepayers.

Although there was some mention during the hearing of Duke Indiana's Edwardsport integrated gasification combined cycle project and Progress Energy Florida's Crystal River 3 nuclear power plant outage, none of the parties took issue with the aforementioned Regulatory Conditions.

The Commission, therefore, finds and concludes that the above provisions of the Regulatory Conditions will protect DEC's and PEC's North Carolina retail ratepayers as much as reasonably possible from the potential impacts of the merger relating to risks of transactions with and commitments of PEC, DEC, and Duke to wholesale customers and other parties.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

The evidence supporting this finding of fact is contained in the Regulatory Conditions and the Code of Conduct.

The Code of Conduct is intended to govern the relationships, activities, and transactions among and between DEC, PEC, and other members of the Duke holding company structure following the merger. Regulatory Condition No. 6.1 binds DEC, PEC, Duke, the other affiliates, and the non-public utility operations to the terms of the Code of Conduct and requires that they comply with its terms.

The proposed Code of Conduct includes revisions to the Code of Conduct approved in the Duke-Cinergy merger proceeding. The most substantive revisions are the following:

(a) Revisions to the definitions to conform them to the definitions in the stipulated Regulatory Conditions.

(b) The inclusion of the additional conditions approved by the Commission in Docket No. E-7, Sub 810, in Sections III.A.2. and III.A.3.

(c) The addition of the following to the exception to the prohibitions in III.A.2 against disclosing Customer Information: To the extent the Commission approves a list of services to be provided and taken pursuant to one or more utility-to-utility service agreements, then Customer Information may be disclosed pursuant to the foregoing exception to the extent necessary for such services to be performed.

(d) The addition of the following exceptions to the prohibitions in Section III.A.3 against the disclosure of Confidential Systems Operation Information: (i) the Information is provided to employees of DEC or PEC for the purpose of implementing, and operating pursuant to, the JDA in accordance with the Regulatory Conditions; and (ii) the Information is necessary for the performance of services approved to be performed pursuant to one or more affiliate utility-to-utility service agreements.

(e) The removal of the cap in III.D.3(d) and the addition of the provision that untariffed non-power, non-generation, and non-fuel goods and services provided by DEC or PEC to DEC, PEC, or the regulated utility affiliates or by the regulated utility affiliates to DEC or PEC, shall be transferred at the supplier's fully distributed cost (as that term is defined in the Regulatory Conditions and Code of Conduct).

(f) The exemption of DEC and PEC from the requirement of advance notice in III.D(8) when a covered technology or trade secret is being transferred between them.

No party took exception to any of the changes to DEC’s and PEC’s previously approved Codes of Conduct.

The Commission, therefore, finds and concludes that the Code of Conduct, as stipulated to by the Applicants, DEC, PEC, and the Public Staff and approved herein, will effectively govern and enable the Commission to review the relationships, activities, and transactions among DEC, PEC, and their affiliates following the merger.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 30

The evidence supporting this finding of fact is contained in the testimony of Applicants witness Good, the testimony of EDF, et al., witness Hahn, and in Section VII of the Regulatory Conditions attached to the Stipulation.

The purposes of Section VII are to ensure that (a) DEC’s and PEC’s capital structure and cost of capital are not adversely affected through their affiliation with Duke, each other, and other affiliates, and (b) both DEC and PEC have access to sufficient equity and debt capital at reasonable costs so as to adequately fund and maintain their current and future capital needs and otherwise meet their service obligations to their customers.

These Regulatory Conditions are similar to, or improvements on, the Regulatory Conditions related to financings approved by the Commission in the Duke-Cinergy merger proceeding. For example, a new condition, Regulatory Condition No. 7.8, governs external debt or credit arrangements and provides that, subject to the limitations imposed in Regulatory Condition No. 8.4:

(a) DEC and PEC may borrow short-term funds through one or more joint external debt or credit arrangements, provided that no borrowing by DEC or PEC under a Credit Facility exceeds one year in duration, absent Commission approval;

(b) No such arrangement shall include, as a borrower, any party other than Duke, DEC, PEC, Duke Indiana, Duke Kentucky, PEF, and, subject to certain limitations, Duke Ohio; and

(c) DEC’s and PEC’s participation in any such arrangement shall in no way cause either of them to guarantee, assume liability for, or provide collateral for any debt or credit other than its own.

If the limitations with respect to Duke Ohio's participation are not met, DEC and PEC are required to discontinue participation within six months after the issuance of an order by the Commission.

EDF, et al., witness Hahn testified that the Regulatory Conditions do not prohibit money pool transactions with unregulated affiliates of DEC and PEC. In their post-hearing Brief, EDF, et al., asserted that the Commission should adopt additional conditions to protect DEC and PEC ratepayers from the risk of exposure to parent and affiliate financial distress, including additional restrictions regarding the use of money pools and establishment of a special purpose entity (SPE) between regulated subsidiaries and the parent holding company.

On rebuttal, Applicants witness Good testified that apparently EDF, et al., witness Hahn had not reviewed the money pool agreement provision of the Regulatory Conditions because it expressly contains the prohibition that he testified was lacking. Regulatory Condition No. 7.7 provides that, subject to the limitations imposed in Regulatory Condition No. 8.4, DEC and PEC may borrow through Duke's Utility Money Pool Agreement (Utility MPA). This condition explicitly continues the prohibition in the existing Utility MPA of loans through Utility MPA being made to, and borrowings being made by, Duke and Cinergy Corporation. Further, Progress was added to this prohibition. This condition also provides that (a) the parties to such an agreement are limited to those participating in Duke's existing Utility MPA plus PEC, PEF (a regulated utility), Progress, and PESC; and that if, after December 31, 2011, certain requirements with respect to Duke Ohio's generation assets are not met, then DEC and PEC must seek further approval from the Commission to continue to participate in the Utility MPA.

Additionally, the preamble to Section VII explicitly states that these Regulatory Conditions do not supersede any orders or directives of the Commission regarding specific securities issuances by DEC, PEC, or Duke, and that approval of the merger by the Commission does not restrict the Commission's right to review, and by order to adjust, DEC's or PEC's cost of capital for ratemaking purposes for the effect(s) of the securities-related transactions associated with the merger.

Other than as discussed above, no party took exception to any of these Regulatory Conditions.

The Commission is not persuaded by the testimony of EDF, et al., witness Hahn or the arguments of EDF, et al., that additional Regulatory Conditions are needed to protect DEC's or PEC's cost of capital or capital structures. Rather, the Commission is of the opinion, and, therefore, finds and concludes, that the Regulatory Conditions included in the Stipulation are reasonable, appropriate and effectively address as much as reasonably possible the concerns related to potential financing issues arising from the merger. In particular, the Commission finds and concludes that the Regulatory Conditions effectively ensure as much as reasonably possible that (a) neither DEC's nor PEC's capital structures and cost of capital are adversely affected because of their affiliation with Duke, each other, and other affiliates, and (b) both DEC and PEC have sufficient access to equity and debt capital at a reasonable cost to adequately fund and maintain their current and future capital needs and otherwise meet their service obligations to their customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 31

The evidence supporting this finding of fact is contained in the Stipulation, Regulatory Conditions, the testimony of Applicants witness Good and the testimony of EDF, et al., witness Hahn.

Section VIII of the Regulatory Conditions addresses the risks and concerns related to corporate governance and ring-fencing issues arising from the merger. These Regulatory Conditions are intended to ensure the continued viability of DEC and PEC and to insulate and protect DEC, PEC, and their North Carolina retail ratepayers from the business and financial risks of Duke and the affiliates within the Duke holding company system, including the protection of utility assets from liabilities of affiliates.

"Ring-fencing" can be defined as the legal walling off of certain assets or liabilities within a corporate system, including the creation of a new subsidiary to protect (i.e., ring-fence) specific assets from creditors. Ring-fencing measures are used to insulate a regulated utility from the potentially riskier activities of unregulated affiliates. From a debt rating agency perspective, ring-fencing mechanisms are techniques used to isolate the credit risks of one company within an affiliated group from the risks of other companies within that group. Concurrent use of numerous ring-fencing measures, including regulatory, financial, structural, and operational restrictions, is considered to be the most effective way to separate risk.

Only EDF, et al., witness Hahn alleged that ring-fencing conditions in addition to those contained in the Regulatory Conditions are required. He recommended that the Commission impose four additional conditions: (a) limiting cash dividend payments to Duke from DEC and PEC to DEC's and PEC's annual net income; (b) requiring DEC and PEC to maintain a capital structure with at least 40 percent equity; (c) requiring that DEC's and PEC's boards of directors each include at least one independent director; and (d) requiring that an SPE be inserted between the parent company and PEC and DEC.

Applicants witness Good responded to each of EDF, et al., witness Hahn's "ring-fencing" proposals. Good testified that, contrary to Hahn's assertions, the rating agencies have not expressed the opinion that either DEC or PEC should be further insulated from the actions of affiliates above and beyond the protective measures that are already in place. Fitch Ratings, S&P, and Moody's Investors Service (Moody's) each reviewed the merger transaction and, on that basis, affirmed the ratings of Progress and its subsidiaries on January 10, 2011. According to witness Good, S&P placed the ratings of Progress, PEC, and PEF on "CreditWatch with Positive Implications," indicating a likely upgrade. The credit ratings of Duke and its subsidiaries were affirmed by S&P and Moody's on the same date.

Applicants witness Good then described the ring-fencing conditions as being intended to ensure the continued viability of DEC and PEC and to insulate and protect DEC, PEC, and their North Carolina retail ratepayers from the business and financial risks of Duke and the affiliates within the Duke holding company system, including the protection of utility assets from liabilities of affiliates.

Regarding EDF, et al., witness Hahn's testimony to the effect that the Regulatory Conditions do not contain any limits on PEC's and DEC's authority to pay dividends and his proposal that the cash dividends paid to Duke by DEC and PEC be limited to DEC's and PEC's annual net income, Applicants witness Good testified, on rebuttal, that both Regulatory Condition Nos. 8.1 and 8.2 provide such limitations and that those limitations are reasonable and appropriate.

Regulatory Condition No. 8.1 requires DEC and PEC to manage their respective businesses so as to maintain an investment grade debt rating on all of their rated debt issuances with all of the debt rating agencies. If the debt rating of either DEC or PEC falls to the lowest level still considered investment grade at the time, a written notice by DEC or PEC must be filed with the Commission and provided to the Public Staff within five days, along with an explanation as to why the downgrade occurred. Furthermore, within 45 days of such notice, DEC or PEC are required to provide the Commission and the Public Staff with a specific plan for maintaining and improving its debt rating. The Commission, after notice and hearing, may then take whatever action it deems necessary consistent with North Carolina law to protect the interests of DEC's or PEC's North Carolina retail ratepayers in the continuation of adequate and reliable service at just and reasonable rates. Regulatory Condition No. 8.2 limits DEC's and PEC's cumulative distributions paid to Duke subsequent to the merger to (a) the amount of retained earnings on the day prior to the closure of the merger, plus (b) any future earnings recorded by DEC and PEC subsequent to the merger.

In response to cross-examination by counsel for EDF, et al., with respect to whether the Regulatory Conditions would allow DEC and PEC to write a dividend check for the total amount of total retained earnings, Applicants witness Good stated that she did not believe the Regulatory Conditions would allow that because DEC and PEC would be in violation of a number of conditions. For example, Good testified that it would be difficult to maintain investment grade ratings if DEC or PEC had zero equity and difficult to meet the condition that requires DEC's and PEC's debt balance to be no more than 65 percent of total capitalization.

Turning to EDF, et al., witness Hahn's second recommendation, that DEC and PEC should be required to maintain a capital structure with at least 40 percent equity, Applicants witness Good explained that, in addition to Regulatory Condition Nos. 8.1 and 8.2, the Commission has statutory authority to approve appropriate capital structures for both DEC and PEC. Furthermore, Good testified that Regulatory Condition No. 8.3 imposes requirements with respect to a minimum equity ratio.

Regarding EDF, et al., witness Hahn's proposal that both DEC and PEC should be required to have at least one independent director, Applicants witness Good explained that Hahn's justification for this proposal appeared to be that it would provide additional protection for DEC's and PEC's North Carolina retail ratepayers if Duke or another affiliate filed bankruptcy. Good pointed out that Regulatory Condition No. 8.10 addresses that situation by requiring DEC or PEC to notify the Commission, in advance if possible, if an affiliate experiences a default on an obligation that is material to Duke or files for bankruptcy and such bankruptcy is material to Duke, DEC or PEC. Good explained that this notice requirement is sufficient to allow the Commission to take whatever action may be appropriate to protect customers from the risks associated with the bankruptcy of Duke or an affiliate.

Additionally, Applicants witness Good observed that Regulatory Condition No. 8.4 allows DEC and PEC to participate in Duke's Utility MPA and any other authorized external joint debt or credit arrangement only to the extent such participation is beneficial to their respective retail ratepayers and does not negatively affect DEC's or PEC's ability to continue to provide adequate and reliable service at just and reasonable rates.

Regarding EDF, et al., witness Hahn's last recommendation, that DEC and PEC be transferred into an SPE, Applicants witness Good testified that this measure is unnecessary. Good noted that Hahn had acknowledged that PEC will be a wholly-owned subsidiary of Progress, which will be a subsidiary of Duke after the merger. Further, given the comprehensive nature of the Regulatory Conditions, Good testified that the transfer of PEC and DEC into an SPE is not warranted, as the Regulatory Conditions require PEC and DEC to operate completely separately from their parent and affiliates, to keep separate books and accounting, and to provide the Commission and Public Staff with advance notice of any activity that might harm PEC or DEC.

In its response to the pre-filed testimony of EDF, et al., witness Hahn, the Public Staff provided excerpts of the Regulatory Conditions and Code of Conduct provisions with ring-fencing implications highlighted to show the revisions that had been made to the Regulatory Conditions approved in the Sub 795 Order approving the Duke-Cinergy merger. The Public Staff also highlighted the additional ring-fencing provisions agreed to by the stipulating parties. The Public Staff further stated that ring-fencing in the regulated utility context generally is intended to protect ratepayers from risks created by unregulated affiliates.

With respect to EDF, et al., witness Hahn's specific recommendations, the Public Staff noted that the Regulatory Conditions require a minimum equity ratio, albeit indirectly. Also, Duke's current Master Credit Facility includes a covenant restricting the ratio of debt to total capitalization on a consolidated basis to 65 percent, which conversely imposes a minimum 35 percent equity ratio. The Public Staff stated that it pursued this approach, rather than a specific minimum percentage of equity, because financial conditions could change. For example, if a subsequent credit arrangement required Duke to limit the ratio of debt to 60 percent of total capitalization, the minimum equity ratio for DEC and PEC would increase to 40 percent.

The Public Staff's response also noted that the Regulatory Conditions explicitly provide that DEC's and PEC's North Carolina retail ratepayers shall be held harmless from all liabilities of Cinergy Corporation and Florida Progress Corporation, and all liabilities of all of their subsidiaries, including liabilities incurred both before and after the earlier mergers.

With respect to bankruptcy, the Public Staff noted that bankruptcy of one of the regulated utility subsidiaries is unlikely given the extent of current state regulation, making the real issue the risks created by unregulated affiliates. To that end, the Public Staff stated that Regulatory Condition No. 8.5, one of the new conditions proposed by the Stipulation, provides a mechanism by which the Commission can determine whether the cumulative investment by Duke in assets, ventures, or entities other than regulated utilities is reasonably likely to affect DEC or PEC. More specifically, this condition requires Duke to "notify the Commission within 90 days following the end of any fiscal year for which Duke Energy reports to the Securities and Exchange Commission assets in its operations other than regulated utilities that are in excess of

22 percent of its consolidated total assets." This condition further provides a process by which parties can file comments in response to the notice and explicitly provides that the Commission can then take action if needed to protect DEC's and PEC's retail ratepayers.

As previously discussed, Regulatory Condition No. 8.4 limits the continued participation of DEC and PEC in the Duke Utility MPA and in other joint debt and credit arrangements with affiliates. It provides that DEC and PEC may continue to participate in such arrangements only to the extent that such participation is beneficial to their respective retail ratepayers and does not negatively affect DEC's or PEC's ability to continue to provide adequate and reliable service at just and reasonable rates.

As discussed above, EDF, et al., contended that the Commission should adopt additional conditions to protect DEC's and PEC's ratepayers from the risk of potential exposure to parent and affiliate financial distress. The Commission, however, is not persuaded that such additional conditions are necessary or appropriate. Rather, the Commission is persuaded by the evidence, including the comprehensiveness of the Regulatory Conditions, the testimony of Applicants witness Good, and the position taken by the Public Staff, that the Regulatory Conditions included in the Stipulation are reasonable and effectively address as much as reasonably possible the potential risks and concerns related to exposure to parent and affiliate financial distress and that the additional ring-fencing measures recommended by EDF, et al., witness Hahn are not necessary.

The Commission, therefore, finds and concludes that the Regulatory Conditions effectively address as much as reasonably possible potential risks and concerns related to corporate governance and ring-fencing issues arising from the merger by ensuring the continued viability of DEC and PEC and insulating and protecting DEC, PEC, and their retail ratepayers from the business and financial risks of Duke and the affiliates within the Duke holding company system, including the protection of utility assets from the liabilities of affiliates.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 32

The evidence supporting this finding of fact is contained in the Regulatory Conditions attached to the Stipulation, and the testimony of Public Staff witness Hoard.

The purpose of Section IX of the Regulatory Conditions is to ensure that the Commission receives sufficient notice to exercise its lawful authority over proposed mergers, acquisitions, and other business combinations involving Duke, DEC, PEC, other affiliates, or the non-public utility operation. Regulatory Condition No. 9.1 provides for Commission approval of future proposed mergers by DEC or PEC. Regulatory Condition No. 9.2 requires that advance notification be filed with the Commission at least 90 days prior to the proposed closing date for the proposed merger, acquisition, or other business combination that is believed not to have an effect on DEC's or PEC's rates or service, but which involves Duke, other affiliates, or the non-public utility operations and which has a transaction value exceeding $1.5 billion. Any interested party may file comments within 45 days of the filing of the advance notification, and, if timely comments are filed, the Public Staff is required to place the matter on a Commission Staff Conference agenda and recommend how the Commission should proceed. This condition further provides that, if the Commission determines that the merger, acquisition, or other business combination requires approval, an order shall be issued requiring the filing of an application, and no closing can occur until and unless the Commission approves the proposed merger, acquisition, or business combination.

In response to questions by the Commission, Public Staff witness Hoard confirmed that Regulatory Condition No. 9.1, among other things, documents the understanding between the Applicants and the Public Staff that a future merger of DEC and PEC must be approved by the Commission.

The Commission, therefore, finds and concludes that the Regulatory Conditions will effectively enable the Commission to exercise its jurisdiction over business combinations involving Duke or other members of the Duke holding company structure following the merger by ensuring that the Commission receives sufficient notice to exercise its lawful authority over proposed mergers, acquisitions, and other business combinations involving Duke, DEC, PEC, other affiliates, or the nonpublic utility operations of DEC and PEC.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 33

The evidence supporting this finding of fact is contained in the Regulatory Conditions attached to the Stipulation.

The Regulatory Conditions in Section X are intended to ensure that the Commission receives adequate notice of, and opportunity to review and take such lawful action as is necessary and appropriate with respect to changes to the structure and organization of Duke, DEC, PEC, and other affiliates, and nonpublic utility operations of DEC and PEC as they may affect North Carolina retail ratepayers.

Regulatory Condition No. 10.1 provides that DEC and PEC are required to file notice with the Commission 30 days prior to the initial transfer or any subsequent transfer of any services, functions, departments, employees, rights, obligations, assets, or liabilities from DEC or PEC to DEBS, PESC, Duke, another affiliate, or a nonpublic utility operation that (a) involves services, functions, departments, employees, rights, obligations, assets, or liabilities other than those of a governance or corporate nature that traditionally have been provided by a service company, or (b) potentially would have a significant effect on DEC's or PEC’s public utility operations.

Regulatory Condition No. 10.2 provides that, upon request, DEC and PEC shall meet and consult with, and provide requested relevant data to, the Public Staff regarding plans for significant changes in DEC's, PEC’s or Duke's organization, structure (including RTO developments), and activities; the expected or potential impact of such changes on DEC's or PEC’s retail rates, operations and service; and proposals for assuring that such plans do not adversely affect DEC’s or PEC’s retail customers. To the extent that proposed significant changes are planned for the organization, structure, or activities of an affiliate or nonpublic utility operation and such proposed changes are likely to have an adverse impact on DEC’s or PEC’s retail customers, then DEC’s and PEC’s plans and proposals for assuring that those plans do not adversely affect those customers must be included in these meetings. DEC and PEC shall inform the Public Staff promptly of any such events and changes.

The Commission, therefore, finds and concludes that the Regulatory Conditions effectively address risks and concerns related to structure and organization arising from the merger as much as reasonably possible by ensuring that the Commission will receive adequate notice of, and an opportunity to review and take such lawful action as is necessary and appropriate with respect to, changes to the structure and organization of Duke, DEC, PEC, and other affiliates, and nonpublic utility operations of DEC and PEC as they may affect North Carolina retail ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 34

The evidence supporting this finding of fact is contained in the Regulatory Conditions attached to the Stipulation.

Section XIII of the Regulatory Conditions provides procedures for the implementation of conditions requiring advance notices and other filings arising from the merger. No party stated any opposition to these Regulatory Conditions.

Regulatory Condition No. 13.1 provides detailed procedures and designated Sub dockets for filings pursuant to the Regulatory Conditions that are not subject to the advance notice provisions of Regulatory Condition No. 13.2. This Regulatory Condition provides that filings related to (a) affiliate matters required by Regulatory Condition Nos. 5.4, 5.5, 5.6, 5.7, and 5.23 and the filing permitted by Regulatory Condition No. 5.3 shall be made by DEC and PEC in Sub 986A and Sub 998A, respectively; (b) financings required by Regulatory Condition No. 7.6, and the filings required by Regulatory Condition Nos. 8.5, 8.6, 8.9, 8.10 and 8.11 shall be made by DEC and PEC in Sub 986B and Sub 998B, respectively; (c) compliance filings required by Regulatory Condition Nos. 3.1(d) and 14.4 and filings required by Sections III.A.2(l), III.A.3(e), (f), and (g), III.D.5, and III.D.8 of the Code of Conduct shall be made in Sub 986C and Sub 998C; (d) the independent audits required by Regulatory Condition No. 5.8 shall be made in Sub 986D; and (e) orders and filings with the FERC, as required by Regulatory Condition Nos. 3.1(d), 3.11 and 5.13 shall be made by DEC and PEC in Sub 986E and Sub 998E, respectively.

Regulatory Condition No. 13.2 provides that advance notices filed pursuant to Regulatory Condition Nos. 3.1(c), 3.3(b), 3.7(c), 3.10(c), 4.2, 5.3, 8.8, and 10.1 shall be assigned a new, separate Sub docket and imposes detailed requirements and procedures for processing such notices.

The Commission, therefore, finds and concludes that Section XIII of the Regulatory Conditions provides appropriate and effective procedures for the implementation of conditions requiring advance notices and other filings arising from the merger.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 35

The evidence supporting this finding of fact is contained in the Regulatory Conditions attached to the Stipulation.

The purpose of Section XIV of the Regulatory Conditions is to ensure that Duke, DEC, PEC, and all other affiliates establish and maintain the structures and processes necessary to fulfill the commitments expressed in the Regulatory Conditions and the Code of Conduct in a timely, consistent and effective manner. The requirements in this section are new.

Regulatory Condition No. 14.1 requires Duke, DEC, PEC, and all other affiliates to devote sufficient resources to the creation, monitoring and ongoing improvement of effective internal compliance programs to ensure compliance with the Regulatory Conditions and the Code of Conduct. It further requires them to take a proactive approach toward correcting any violations and reporting them to the Commission, including the implementation of systems and protocols for monitoring, identifying, and correcting possible violations, a management culture that encourages compliance among all personnel, and the tools and training sufficient to enable employees to comply with Commission requirements.

Regulatory Condition No. 14.2 requires DEC and PEC to designate a chief compliance officer who will be responsible for compliance with the Regulatory Conditions and Code of Conduct. This person's name and contact information must be posted on DEC's and PEC's Internet Website. Regulatory Condition No. 14.3 requires that annual training be provided by DEC and PEC on the requirements and standards contained within the Regulatory Conditions and Code of Conduct to all of their employees, including service company employees, whose duties in any way may be affected by such requirements and standards.

Finally, Regulatory Condition No. 14.4 states that if DEC and PEC discover that a violation of the requirements or standards contained within the Regulatory Conditions and Code of Conduct has occurred, then they are required to file a statement with the Commission describing the circumstances leading to that violation and the mitigating and other steps taken to address the current or any future potential violation.

The Commission, therefore, finds and concludes that these Regulatory Conditions will effectively ensure monitoring and compliance with the Regulatory Conditions and the Code of Conduct by requiring Duke, DEC, PEC, and all other affiliates to establish and maintain the structures and processes necessary to fulfill the commitments expressed in the Regulatory Conditions and the Code of Conduct in a timely, consistent and effective manner.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

The evidence supporting this finding of fact is contained in the application, the Stipulation, and the testimony of Applicants witnesses Rogers, Johnson, Sims, and Williams, EDF, et al., witness Hahn, NC WARN witness Colton and NCSEA witness Urlaub.

The Applicants state in the application that the proposed merger in no way diminishes the Commission's authority to regulate the service quality of DEC and PEC. Section XI of the Regulatory Conditions attached to the Stipulation contains ten separate provisions that are intended to ensure that DEC and PEC continue to implement and further their commitment to providing superior utility service by meeting recognized service quality indices and implementing the best practices of each other and their utility affiliates to the extent reasonably practicable. These provisions include overall service quality, best practices, reliability reports, notice of audits by the North American Electric Reliability Corporation and the SERC Reliability Corporation, right-of-way maintenance expenditures and clearance practices, customer access to service representatives and other services, call center operations, customer surveys, and regular meetings with the Public Staff on matters related to service quality. In addition, Paragraph No. 14 of the Stipulation provides that DEC, PEC, and the Public Staff will work together after the close of the merger to propose a rulemaking proceeding for standardizing the indices commonly used in the electric utility industry to measure service quality for use in reporting by North Carolina electric utilities.

Witnesses Rogers and Johnson emphasized DEC's and PEC's commitment to safe and reliable service. Witness Sims testified that she and co-worker Mullinax started the integration process by saying that safety, reliability, and customer service are important to their business and they wanted to form not only the largest utility but also the best utility and expected safety and reliability and customer service to continue at its present quality level, if not improve. Sims stated that it is the Applicants' responsibility to deliver safe and reliable power and customer service at all times, regardless of the merger, and they would continue to monitor that as a normal part of doing business. Witness Williams pointed out that the Commission's rules governing service quality, billing, deposits, and collections will continue to apply to all customers after the merger; the Public Staff's Consumer Services Division will still investigate customer complaints and ensure that DEC and PEC comply with the Commission's rules and treat their customers fairly and respectfully; a customer can still file a formal complaint with the Commission to resolve disputes; and several of the proposed Regulatory Conditions provide added protections. Williams stated that these multiple safeguards ensure that the merger will not result in a degradation of service to DEC's and PEC's low-income and smaller customers.

NC WARN witness Colton proposed that the Commission impose additional regulatory conditions beyond those contained in the Stipulation. Witness Colton asserted that, in general, the larger the company the less responsive it is to its smaller customers and the more rigid its customer service practices. He therefore recommended that the Commission require PEC and DEC to implement several energy efficiency programs focused on low-income customers and low income assistance programs as conditions for approval of the merger. NCSEA also asked the Commission to evaluate and consider mitigating measures to address NCSEA's perceived impact of the merger on low income customers.

Applicants witness Williams questioned witness Colton's basic premise and addressed each of his recommendations. Witness Williams explained that the harms postulated by Colton are entirely speculative. There is no evidence that the combined company will be less attentive to or less sensitive to its smaller customers. Thus, witness Williams concluded that Colton's various mitigation measures are unneeded.

Witness Williams testified that the merger will not impair or modify the Commission's oversight, consumer protection authority or regulatory control over the combined company. Williams noted that the Commission's rules governing service quality, billing, deposits and collections will still apply to PEC and DEC after the merger. These rules include: Rule R8-6 which requires a utility to thoroughly investigate all customer complaints; Rule R8-14 which requires utilities to test meters upon customer request; Rules R8-16 and 17 which establish service frequency and voltage requirements; Rule R8-20 which governs disconnection of service; Rule R8-24 which requires service extensions; Rule R8-44 which establishes billing adjustment procedures for over- and under-charges; Rule R8-51 which requires a utility to provide a customer his or her billing history upon request; and the entire Rule R12 section which contains the rules associated with establishment of service, security deposits, and disconnection for non-payment.

Further, witness Williams testified that the Public Staff's Consumer Services division will still investigate customer complaints and ensure PEC and DEC comply with the Commission's rules and treat their customers fairly and with respect. Customers can still file formal complaints with the Commission and Regulatory Conditions 11.8, 11.9 and 11.10 require PEC and DEC to have knowledgeable and experienced customer service representatives available 24 hours a day to handle all types of customer service inquiries. The combined company will continue to provide quarterly reports to the Public Staff on call center performance, and conduct customer service surveys.

Witness Williams concluded that these multiple consumer safeguards remain intact and ensure that the merger will not result in a degradation of service to PEC's and DEC's low income and smaller customers.

Regarding witness Colton's claim that the combined company will implement more rigid customer service procedures, witness Williams disagreed with that assertion, explaining that each utility today has data processing and information systems that accommodate consideration of individual customer circumstances. While the systems may be consolidated or standardized at some point after the merger, that action will in no way impede a customer service representative's ability to consider individual customer circumstances. He stated that an information system is merely a tool to facilitate customer interaction. The tool does not control or constrain the range of options available to customer service representatives. Witness Williams observed that witness Colton offered no support for his allegation that adoption of a single computer system will alter or constrain discretionary decisions by customer service representatives. Neither the consolidation of information systems nor any other action resulting from the merger will erode rules adopted by the Commission. The utilities will continue to comply with all Commission rules and regulations, including those focused on "payment-troubled" customers. In fact, the proposed Regulatory Conditions add protections above those required by the Commission's rules and regulations.

With regard to witness Colton's specific mitigation proposals, witness Williams explained that such proposals are not necessary and should only be considered in PEC's and DEC's integrated resource planning (IRP) proceedings. Witness Williams stated that all of the mitigation measures in question involve questions of resource planning. The role energy efficiency and low income customer weatherization and support should play in the provision of electric service must be considered in the Commission's annual IRP process. Only in that context can the least cost mix of resources be identified. He observed that the Commission has adopted comprehensive resource planning rules and rules governing the selection, filing and approval of energy efficiency measures and programs and that Colton's concepts and proposals should be addressed via these established Commission proceedings.

With regard to Colton's recommendation that PEC and DEC be required to make annual payments to a North Carolina financing organization to provide monetary support to low income customers, witness Williams testified that this is not the first time NC WARN has proposed creation of such a public benefits fund (PBF). He noted that in the fall of 2008, NC WARN proposed adoption of a PBF to fund an independently administered energy efficiency program. After considering the comments of numerous parties, the Commission, in its December 2, 2008 Order in Docket No. E-100, Sub 120, concluded that "the Commission lacks sufficient statutory authority to compel the establishment and funding of an independently administered energy efficiency program such as that proposed by NC WARN. Moreover, the Commission determines that establishment of such a program at this time is inconsistent with the provisions of Senate Bill 3 and the intent of the General Assembly expressed therein." Witness Williams asserted that nothing has changed to alter the Commission's previous conclusion.

With respect to witness Colton's recommendation that the Commission establish energy efficiency portfolio standards (EEPS), an arrearage management program (AMP), or implement best energy efficiency practices for all utilities in the combined company, witness Williams explained that again all of these mitigation measures are based upon the assumption that the merger will detrimentally impact low income and small customers. However, other than Colton's bare assertion that bigger companies are, in general, less sensitive to low income customers than smaller companies, there is nothing in the record to support this allegation.

With regard to an AMP, witness Williams testified that both DEC and PEC have options available to assist customers with resolving arrearages. Both utilities offer installment payment plans, equal payment plans, credit extensions, and other assistance to help customers with payment of past-due bills. The utilities are not proposing to eliminate any of these currently available options. In addition, witness Williams reiterated that the Commission's rules pertaining to customer payments, deposits, billing, and collections are not changing, and the Public Staff Consumer Services Division will continue to assist customers.

With regard to EEPS, witness Williams explained that Senate Bill 3 established a renewable energy and energy efficiency portfolio standard (REPS) that DEC and PEC must meet. He stated that this merger is neither the appropriate time nor place to address DSM/EE program selection. The Commission has a rigorous IRP process in place to evaluate and select resources, including DSM/EE. The Commission also requires PEC and DEC to annually file their REPS compliance plans. The Commission reviews the plans and determines whether they should be approved. In addition, the Commission has specific rules and procedures in place to guide the evaluation and approval of specific DSM/EE programs. Witness Williams concluded that the proper forum to address DSM/EE options is in the IRP proceedings and during the DSM/EE approval process.

The Commission has carefully considered the concerns expressed by witness Colton regarding the potential loss of attention and responsiveness by a larger company to the circumstances of individual customers. The Commission concludes that the Regulatory Conditions agreed to by the Applicants and the Public Staff and attached to the Stipulation adequately address the preservation of high quality service for all of DEC's and PEC's customers. Further, the Commission is confident of its ability and that of the Public Staff to ensure that this commitment is met.

The Commission is not persuaded that the evidence presented by witness Colton is sufficient to require that additional service quality, customer service, energy efficiency or customer assistance programs should be established as part of the Commission's approval of the merger. The Commission concludes that there has not been sufficient evidence presented that customer service or service quality will be harmed as a result of the merger. All of the current safeguards regarding customer service and service quality will continue following the merger. Furthermore, many of the mitigation methods proposed by NC WARN can be more appropriately addressed in PEC's and DEC's annual IRP, DSM/EE and/or REPS proceedings.

In their post-hearing Brief, EDF, et al., asserted that the Commission should adopt additional conditions, designated as Proposed Conditions 3.a.-d., to ensure that PEC's and DEC's customers receive maximum benefits from energy efficiency. They recommended that the Commission require a commitment at the holding company level for the Carolinas operating companies to achieve the energy efficiency savings performance target approved by the Commission in Docket No. E-7, Sub 831 (save-a-watt); require a study of energy efficiency best practices by an independent consultant to ensure implementation of best practices at the merged holding company and its Carolinas operating companies; require DEC and PEC to conduct and update at least every four years a joint analysis of the potential for cost-effective energy efficiency resources; require the Applicants to convene a stakeholder process to develop and propose for Commission approval a new compensation and incentive mechanism for energy efficiency that would take effect upon expiration of the currently approved DEC and PEC mechanisms. In addition, EDF, et al., proposed a condition to require an additional contribution from Duke's shareholders for the purpose of funding low-income weatherization, in an amount to be determined by the Commission.

On June 18, 2012, EDF, et al., filed comments in which it stated that since the filing of their post-hearing Brief, EDF, et al., entered into a settlement agreement with the Applicants that resolved the issues between them in the South Carolina proceeding. As a result of this settlement EDF, et al., stated that they desired to withdraw Proposed Conditions 3.a.-d.

The Commission is not convinced that a condition requiring an additional contribution from Duke's shareholders for the purpose of funding low-income weatherization would be reasonable or appropriate in this proceeding. Senate Bill 3 established a REPS that DEC and PEC must meet. The Commission has an annual IRP process to evaluate and select resources, including DSM/EE. The Commission also requires PEC and DEC to annually file their REPS compliance plans. The Commission reviews the plans and determines whether they should be approved. In addition, the Commission has specific rules and procedures in place to guide the evaluation and approval of specific DSM/EE programs. Thus, the proper forum to address DSM/EE options is in the IRP proceedings and during the DSM/EE approval process. Therefore, the Commission is not persuaded that the proposed additional conditions are reasonable or appropriate.

In its post-hearing Brief, NC WARN recommended that the Commission adopt additional conditions requiring the Applicants to make a contribution of $27 million annually over the next decade for energy efficiency and conservation-based services that NC WARN asserted would partially mitigate the impacts of the merger on low-income families; create an AMP that would partially mitigate the impacts of the merger on low-income families; require that best practices in energy efficiency and conservation programs be a priority of the new Duke Energy; and order that side agreements between the parties be entered into the record.

The Commission is not convinced that NC WARN's recommended conditions are reasonable or appropriate in this proceeding. The Commission has an annual IRP process to evaluate and select resources, including DSM/EE. As stated above, the Commission reviews the plans and determines whether they should be approved. In addition, the Commission has specific rules and procedures in place to guide the evaluation and approval of specific DSM/EE programs. Thus, the proper forum to address DSM/EE options is in the IRP proceedings and during the DSM/EE approval process.

In response to NC WARN's request that all settlement agreements be filed with the Commission, in the Commission's November 2, 2011 Post-Hearing Order, Question No. 18, the Commission directed the Applicants to provide the Commission with a copy of all settlement agreements related to the merger. On November 17, 2011, the Applicants filed their verified responses to the questions propounded by the Commission in the Post-Hearing Order, including copies of 18 settlement agreements related to the merger. On May 17, 2012, the Applicants filed copies of two additional settlement agreements and 12 revised agreements. On June 14, 2012, the Applicants filed a copy of one additional settlement agreement. All of these documents were filed by the Applicants under seal as proprietary and confidential. Therefore, on and after November 17, 2011, all parties to this proceeding had the opportunity to sign a confidentiality agreement and obtain copies of the Applicants' settlement agreements with other parties.

The Commission, therefore, finds and concludes that the Commission's existing regulatory authority and procedures and the Regulatory Conditions will effectively ensure that DEC and PEC maintain a strong commitment to customer service after the merger.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 37

The evidence supporting this finding of fact is contained in the Regulatory Conditions attached to the Stipulation.

Section XII of the Regulatory Conditions is intended to ensure that DEC's and PEC's North Carolina retail ratepayers do not bear any additional tax costs as a result of the merger and that they receive an appropriate share of any tax benefits associated with the service company affiliates, as defined in Section I of the Regulatory Conditions.

Regulatory Condition No. 12.1 provides that under any tax sharing agreement neither DEC nor PEC will seek to recover from their North Carolina retail ratepayers any tax cost that exceeds DEC's or PEC's tax liability calculated as if DEC and PEC were stand-alone taxable entities for tax purposes.

Regulatory Condition No. 12.2 provides that the appropriate portion of any income tax benefits associated with DEBS and PESC will accrue to the North Carolina retail operations of DEC and PEC for regulatory accounting, reporting, and ratemaking purposes.

No party questioned the appropriateness or effectiveness of Regulatory Condition Nos. 12.1 and 12.2.

The Commission, therefore, finds and concludes that Regulatory Condition Nos. 12.1 and 12.2 will effectively ensure as much as reasonably possible that DEC's and PEC's North

Carolina retail ratepayers (a) are protected from any adverse effects of a tax sharing agreement, and (b) will receive an appropriate portion of income tax benefits associated with DEBS and PESC.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 38

The evidence supporting this finding of fact is contained in the Regulatory Conditions attached to the Stipulation.

Section V of the Regulatory Conditions is intended to ensure that (a) costs incurred by DEC and PEC arising from transactions with affiliates are properly incurred, accounted for, and directly charged, directly assigned, or allocated to DEC's and PEC's North Carolina retail operations, and (b) only those costs that produce benefits for DEC’s and PEC’s North Carolina retail ratepayers are included in their respective cost of service for retail ratemaking purposes.

Regulatory Condition No. 5.1 provides that in accordance with North Carolina law the Commission and the Public Staff will continue to have access to the books and records of DEC, PEC, Duke, other affiliates, and the nonpublic utility operations of DEC and PEC.

No party questioned the effectiveness of Regulatory Condition No. 5.1.

The Commission, therefore, finds and concludes that the Regulatory Conditions will effectively operate to ensure as much as reasonably possible that the Commission and the Public Staff continue to have access to the books and records of DEC, PEC, and other members of the Duke holding company system in accordance with North Carolina law.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 39

The evidence supporting this finding of fact is contained in the application, the testimony of Applicants witnesses, the Applicants’ verified responses to the Commission’s Post-Hearing Order, and the testimony of NCSEA witness Urlaub, EDF, et al., witness Hahn, Public Staff witness Morey, and Public Staff witness Hoard.

NCSEA witness Urlaub testified that the merger is not motivated by potential fuel savings or any operational efficiency, citing the investment analyst reports attached to the application as Exhibit 2. Urlaub argues that these third-party analysts focused on the strategy behind the merger and that, therefore, the merger does not appear to be driven by the metrics that traditionally underlie mergers. While conceding that the merger produces benefits, he questioned whether the benefits exceed the costs. He further opined that whether benefits from the merger exceed the risks and costs cannot be easily discerned because the Applicants failed to discuss any costs, risks or potential harms resulting from the merger.

The concerns expressed by EDF, et al., witness Hahn have been discussed extensively in this Order and need not be repeated here. In short, EDF, et al., concedes that the merger will provide benefits, but insists that it has not been shown that North Carolina would enjoy benefits commensurate with the expected costs.

As discussed earlier, Public Staff witness Hoard testified that he had reviewed the existing Regulatory Conditions and Codes of Conduct approved for DEC and PEC and the set attached to the Stipulation. He stated that, as a regulatory accountant, he would prefer the Regulatory Conditions and Code of Conduct that were included with the Stipulation.

Applicants witness Williams testified that the merger application addresses the risks associated with the merger, particularly with respect to the proposed regulatory conditions. He opined that the lengthy and comprehensive conditions included in the Stipulation fully address the risks associated with the merger. With respect to NCSEA witness Urlaub's testimony, witness Williams testified that NCSEA speculates that the financial benefits of the merger will be used to invest in utility assets that NCSEA does not support, in particular nuclear generation. Williams testified that this is a risk that NCSEA faces pre-merger, the safeguard for which is the Commission's integrated resource planning (IRP) procedures and the requirement that a utility obtain a certificate of public convenience and necessity (CPCN) before beginning the construction of a new generating unit.

The Commission concludes that NCSEA witness Urlaub's reliance on the investment analyst reports filed as Exhibit 2 is misplaced because they do not support his assertion that the merger is not motivated by potential fuel savings or any operational efficiencies. Indeed, these investment analyst reports actually support the opposite conclusion. For example, the Oppenheimer report does not question that the merger will result in six percent savings from combined O&M expenses, which is identified as $344 million. In fact, it states that ten percent savings in the Carolinas have been assumed. This report further discusses the effect of the merger on the pursuit of new clean coal investments, along with nuclear, and the benefits to Duke with respect to the dilution of its unregulated operations' exposure in Ohio. The Baird analysis emphasizes the need to fund substantial infrastructure investments, which is a far broader category than nuclear. It also emphasizes the estimated annual $300 to $420 million non-fuel O&M savings and the five-year estimate of $600 to $800 million in joint dispatch and fuel savings. Finally, the Bank of America/Merrill Lynch report similarly emphasizes the substantial expected non-fuel savings and the immediate customer savings over the first five years due to fuel and dispatch savings.

As discussed previously, many of the risks cited by NCSEA witness Urlaub are risks both DEC and PEC face today and will continue to face irrespective of whether the merger is consummated. Other risks identified have been too tenuously linked to the merger to be given any weight. Further, both NCSEA and EDF, et al., have conceded that the merger results in benefits. Based on the conclusions herein with respect to the benefits of the merger to DEC's and PEC's North Carolina retail ratepayers and the effectiveness of the Regulatory Conditions and Code of Conduct in protecting North Carolina retail ratepayers from merger risks, the Commission finds and concludes that the Regulatory Conditions and the provisions of the Stipulation, as approved herein, will protect DEC's and PEC's North Carolina retail ratepayers as much as reasonably possible from known and potential costs and risks of the merger and, further, that there are sufficient benefits to offset the known and potential costs and risks.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 40

The evidence supporting this finding of fact is contained in the application, in G.S. 62-133.8, 62-133.9, and 62-110.1, Commission Rules R8-60, R8-61, R8-67 and R8-68, the testimony of Public Staff witness Morey, the rebuttal testimony of Applicants witnesses Williams and Harris, the testimony of NCSEA witness Urlaub and the testimony of EDF, et al., witness Hahn.

Public Staff witness Morey testified that he reviewed and critiqued the market power analysis performed by the Applicants. Morey testified that in his view a full audit of the Market Power Study was unnecessary in this proceeding because the retail customers of DEC and PEC are protected by the Commission's cost-of-service ratemaking authority, and the FERC has the jurisdictional responsibility for protecting wholesale customers from market power. Morey concluded that even though the merger increases the concentration of generation and transmission assets in the Carolinas, the regulatory oversight and controls in place at the retail and wholesale level would offset the potential market power that the merger might create. At the wholesale level, DEC and PEC will continue to have cost-based rate authority within their control areas and market-based rate authority only for sales outside of their control areas. In addition, the elimination of rate pancaking between DEC and PEC will potentially increase economic opportunities for wholesale customers in a broader wholesale energy market. Therefore, witness Morey did not believe that the Commission needed to take any steps to guard against the potential exercise of market power by DEC and PEC in post-merger North Carolina retail markets.

In response to the Market Power Study submitted as Exhibit 7 to the application, NCSEA witness Urlaub asserted that the HHI data shown therein are of very little value when the merging companies operate in separate service territories. He further asserted that the Applicants' competition analysis is limited to wholesale market power and does not examine the impact of the merger on retail markets. Finally, he asserted that the Market Power Study is inadequate because the Applicants did not study the impact of the merger on those companies that compete to sell goods and services to DEC and PEC.

Applicants witness Harris testified that Exhibit 7 contains a detailed discussion of the Market Power Study results and the modeling and input assumptions. He further stated that the purpose of the required market power study is to judge the ability of regional suppliers to compete and deliver power in DEC's and PEC's service territories. With respect to NCSEA witness Urlaub's assertion concerning the applicability of the study when the relevant utilities operate in separate service territories, witness Harris stated that this assertion displayed a lack of understanding regarding the nature of the Market Power Study. The fact that DEC and PEC are located in separate service territories in no way undercuts the validity of the study. With respect to retail markets, Harris responded that by law there is no retail competition in North Carolina and, therefore, no purpose would be served by attempting to analyze how the merger could affect retail competition.

Both NCSEA witness Urlaub and EDF, et al., witness Hahn asserted that the merger of Duke and Progress will detrimentally impact the market for renewable energy in North Carolina. This assertion was based on the belief that with both PEC and DEC under common ownership they will enjoy greater leverage in the purchase of renewable energy, they will invest in renewable energy resources themselves notwithstanding the availability of more cost effective renewable resources from third parties, and they will use their financial strength to pursue traditional supply side resources, such as nuclear generation, rather than renewable generation.

Applicants witness Williams addressed these concerns. He explained that the risk that PEC and DEC will invest in utility assets that NCSEA and EDF, et al., do not support is the same risk they face today. The venue to discuss and debate utility resource selection is the Commission's annual integrated resource planning (IRP) proceeding established by G.S. 62-110.1 and Commission Rule R8-60, and the proceeding in which the utility seeks a certificate of public convenience and necessity from the Commission to construct a new generating resource pursuant to G.S. 62-110.1, G.S. 62-82 and Commission Rule R8-61. Williams asserted that it is through these proceedings that the Commission determines, with full input and participation from interested parties, whether the resources proposed by a utility to meet its customers' forecasted energy needs is the least cost and most appropriate resource. Thus, Williams concluded that these concerns should be addressed in the IRP and certificate proceedings and not this merger application.

With regard to witness Urlaub's recommendation that the Commission consider supporting third party sales of energy by solar generators directly to PEC's and DEC's customers, Williams testified that this proposal is misplaced for two reasons. First, G.S 62-110.2 establishes the service rights of North Carolina's electric public utilities. Within a utility's assigned territory the utility is required to plan for and serve all customers. The Commission and the State's utilities are not allowed to waive or ignore this law. Whether the law should be changed is a policy issue to be addressed by the General Assembly. The General Assembly has in fact decided to study this issue. Second, Williams explained that assuming such third party generators were lawful, whether they should be allowed should be addressed in the utility's IRP proceeding. He testified that this merger proceeding is not the forum for the Commission to determine whether third party generation is least cost or needed to meet the electricity needs of North Carolina's citizens.

Regarding the allegations that post-merger PEC and DEC will misuse their buying power in purchasing renewable energy or to improperly participate in the renewable market, witness Williams explained that it is not necessary to engage in this debate at all, much less in this proceeding. He noted that the Commission has adopted Rule R8-67 to implement the renewable portfolio standard requirement of G.S. 62-133.8. This rule establishes annual proceedings to investigate PEC's and DEC's plans, costs, and progress in meeting their REPS obligations. In those proceedings the utilities must describe in detail their renewable energy procurement plans and strategy, accomplishments to date, incurred costs, and forecasted compliance costs. He further noted that witness Hahn's statement in his testimony that following the merger DEC and PEC will have no obligation "to solicit the best or most cost effective projects" is simply wrong. The Commission will continue to closely monitor and regulate PEC's and DEC's renewable energy efforts and their compliance with G.S. 62-133.8. Furthermore, on cross-examination Hahn indicated he was not aware of the Commission's decision issued December 31, 2008, in Docket No. E-7, Sub 856, in which the Commission specifically ruled that the State's utilities are required to comply with G.S. 62-133.8 by selecting the least cost mix of renewable, energy efficiency and utility self-build resources to meet their REPS obligations. Thus, any concerns regarding PEC's and DEC's renewable energy resource plans or actions should be addressed in the annual REPS proceedings if and when they arise, not in this merger proceeding.

With regard to witness Urlaub's concern that post-merger PEC and DEC will misuse their purchasing power to the detriment of the renewable energy market, the Commission is not persuaded that the merger will create any greater renewable energy purchasing power by PEC and DEC, or otherwise alter their REPS requirements or processes. In addition, the Commission notes, as explained in its order issued in Docket No. E-7, Sub 856, that PEC and DEC will continue to be required to meet their REPS renewable energy obligations in the least cost manner. In doing so, they minimize the rate impact to their customers of complying with the REPS statutory mandate. Further, to the extent the merger allows PEC and DEC through more efficient procurement processes to lower their REPS compliance costs, this will be a direct benefit to their North Carolina customers.

With respect to NCSEA's assertion that the Applicants should have studied the impact of the merger on companies that compete to sell goods and services to DEC and PEC, Applicants witness Harris responded that this is not a shortcoming of the Market Power Study. Harris opined that the evidence demonstrates that the merger will tend to lead to a reduction in the prices DEC and PEC pay, a result that will benefit retail ratepayers. A market power study is designed to measure the degree of competition among electricity suppliers. It is not intended to measure the costs and benefits to other businesses, and it does not relate to the impact of the combination of DEC and PEC so far as their procurement processes are concerned.

The Commission concludes that this merger proceeding is not the proper forum in which to determine whether additional energy efficiency programs should be created by PEC and DEC. It is also not the proper forum in which to adopt a renewable energy resource solicitation and selection process, nor is it the proper forum to decide what types and how much, if any, additional renewable energy PEC and DEC should procure as part of their generation resource portfolios. As discussed earlier, G.S. 62-110.1 and G.S. 62-133.9 require the State's utilities to select the least cost mix of resources to meet the electricity needs of their customers. The Commission conducts annual IRP proceedings pursuant to Commission Rule R8-60 to investigate the utilities' resource plans. These annual resource planning proceedings are the proper forum for consideration of whether new resources - coal, natural gas, solar, wind, nuclear, or other - should be purchased or built by a public utility to meet forecasted demand. It is not possible for the Commission to make a well-informed decision based on the evidence in this merger proceeding regarding what size and type of new resources should be built or obtained by PEC and DEC.

Furthermore, the Commission conducts annual proceedings pursuant to Commission Rule R8-67 to evaluate, review and approve PEC's and DEC's efforts and plans to comply with the REPS requirements of Senate Bill 3. Those proceedings are the proper forum for the Commission to consider the solicitation process used by PEC and DEC to obtain renewable energy resources and evaluate their decisions and plans for compliance.

Finally, the Commission has adopted Commission Rule R8-68 to govern the approval of new DSM/EE programs. This rule requires the filing of comprehensive information regarding proposed new programs, including cost-effectiveness tests, to assist the Commission in determining whether a proposed program should be approved. Consideration of new DSM/EE programs should be in proceedings conducted pursuant to Rule R8-68 where all the pertinent information is filed and examined, not in a merger proceeding such as this.

Similar to NC WARN witness Colton, NCSEA witness Urlaub also advocated that the Commission require PEC and DEC to provide additional energy efficiency programs and implement a public benefits fund (PBF) as a condition of merger approval.

With regard to witness Urlaub's proposals, witness Williams explained that such measures are not necessary and, further, would be more proper for consideration in PEC's and DEC's IRP proceedings. Witness Williams stated that all of Urlaub's suggestions involve questions of resource planning. The role energy efficiency and low-income customer weatherization and support should play in the provision of electric service must be considered in the Commission's annual IRP process. According to Williams, only in that context can the least cost mix of resources be identified and fully evaluated. He observed that the Commission has adopted comprehensive resource planning rules and procedures governing the selection, filing and approval of energy efficiency measures and programs and that Urlaub's concepts and proposals should be addressed via these established Commission proceedings.

With regard to Urlaub's recommendation that the Commission adopt a PBF for North Carolina, witness Williams testified that this is not the first time a party has proposed the creation of a PBF. He noted that in the fall of 2008, NC WARN proposed adoption of a PBF to fund an independently administered energy efficiency program. After considering the comments of numerous parties, the Commission, in its December 2, 2008 Order in Docket No. E-100, Sub 120, concluded that "the Commission lacks sufficient statutory authority to compel the establishment and funding of an independently administered energy efficiency program such as that proposed by NC WARN. Moreover, the Commission determines that establishment of such a program at this time is inconsistent with the provisions of Senate Bill 3 and the intent of the General Assembly expressed therein." Witness Williams asserted that nothing has changed to alter the Commission's previous conclusion.

In its post-hearing brief, NCSEA recommended that the Commission adopt additional conditions requiring DEC and PEC to waive their exclusive service franchises and collaborate with NCSEA on the design and implementation of a third party sales program. Further, NCSEA recommends that the Commission evaluate and consider three measures to address the alleged impact of the merger on low income residents and similarly situated entities such as small businesses, and to shore-up what Urlaub perceives to be the limited response to these concerns in the Stipulation of the Applicants and the Public Staff. The three measures recommended by Urlaub are (1) creation of a third party administered PBF that is complimentary to existing utility efficiency programs and serves customer segments who otherwise have limited or no access to needed efficiency measures, (2) authorization for the applicants to offer on-bill financing at low interest rates to assist customers in implementing efficiency measures, and (3) ensuring that bill pay assistance programs remain adequately funded.

The Commission has carefully considered the proposals advocated by witness Urlaub and the proposed additional conditions propounded by NCSEA. The Commission is not persuaded that the evidence presented by Urlaub is sufficient to support a Commission requirement as part of the Commission's approval of the merger that DEC and PEC offer on-bill financing at low interest rates to assist customers in implementing efficiency measures and to ensure that bill pay assistance programs remain adequately funded. Further, as previously discussed, the establishment of third-party sales and a PBF are matters more appropriately addressed by the General Assembly.

In their post-hearing Brief, EDF, et al., proposed additional conditions that it feels are needed to mitigate the effects of the merger on renewable energy procurement and development in North Carolina, including requiring Duke to contribute $10 million annually over five years for the purposes of developing and implementing new renewable energy technologies, or implementing existing renewable energy technologies that are not being applied in the Carolinas; and requiring DEC and PEC to adopt a procurement process for renewable energy resources that is independent, transparent and project neutral.

The Commission is not convinced that this merger proceeding is a proper forum in which to adopt a renewable energy resource solicitation and selection process, nor is it the proper forum to decide what types and how much, if any, additional renewable energy PEC and DEC should procure as part of their generation resource portfolios. As discussed previously, G.S. 62-110.1 and G.S. 62-133.9 require the State's utilities to select the least cost mix of resources to meet the electricity needs of their customers. The Commission conducts annual IRP proceedings pursuant to Commission Rule R8-60 to investigate the utilities' resource plans. These annual resource planning proceedings are the proper forum for consideration of whether new resources - coal, natural gas, solar, wind, nuclear, or other - should be purchased or built by a public utility to meet forecasted demand. It is not possible for the Commission to make a well-informed decision in this merger proceeding regarding what additional resource expenditures, if any, should be made by DEC and PEC.

Furthermore, the Commission conducts annual proceedings pursuant to Commission Rule R8-67 to evaluate, review and approve PEC's and DEC's efforts and plans to comply with the REPS requirements of Senate Bill 3. Those proceedings are the proper forum for the Commission to consider the solicitation process used by PEC and DEC to obtain renewable energy resources and to evaluate their decisions and plans for compliance.

On June 18, 2012, NCSEA filed comments indicating that the impact of the FERC's June 8, 2012 Orders on the merger proceeding was negligible. Thereafter, NCSEA reiterated its three requested merger conditions that were set forth in its November 28, 2011 post-hearing Brief. As fully discussed above, the Commission is not persuaded that the additional conditions proposed by NCSEA are necessary or appropriate.

EDF, et al. further stated that since the filing of their post-hearing Brief, EDF, et al., entered into a settlement agreement with the Applicants that resolved the issues between them in the South Carolina proceeding. As a result of this settlement agreement, EDF, et al., stated that it desired to withdraw Proposed Conditions 2.a.-c. and 3.a.-d. on page 47 of their post-hearing Brief. EDF, et. al., thereafter reiterated the need for the Applicants to contribute $10 million annually over five years for the purposes of developing and implementing new renewable energy technologies, or implementing existing renewable energy technologies, and to adopt an independent procurement process for renewable resources. Further, EDF, et al., added that if the

Commission was inclined to direct funding to renewable energy studies, that the funding should be directed to an offshore wind development fund, offshore wind meteorological towers and geotechnical studies, and third-party sales of renewable energy. As fully discussed above, the Commission is not persuaded that the additional conditions proposed by EDF, et al., are necessary or appropriate.

The Commission, therefore, finds and concludes that the regulatory oversight and controls in place at the retail level are sufficient to protect retail ratepayers as much as reasonably possible from any potential retail market power effects of the merger.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 41

The evidence supporting this finding of fact is contained in the supplemental testimony and exhibits of Public Staff witness Hoard, the supplemental and further supplemental testimony of Applicants' witness Weintraub, the testimony at the June 25, 2012 hearing, the FERC's June 8, 2012 Market Power Order, the Supplemental Stipulation, as amended, the Public Staff's June 13, 2012 comments, and the Applicants' June 25, 2012 FERC Acceptance Letter.

Witness Weintraub described the three components of the revised wholesale market power mitigation plan, specifically: (1) an interim mitigation sales mechanism, which involves the sale of capacity and energy to certain wholesale entities; (2) a "stub" mitigation proposal, which involves reserving transmission capacity between the DEC and PEC east balancing authority areas (BAAs) for use by third parties; and (3) a permanent mitigation proposal, which requires the construction of transmission facilities and the periodic non-economic operation of PEC's Roxboro and Mayo facilities.

Weintraub testified that under the interim mitigation measure, DEC and PEC will sell energy and capacity as follows:

(1) DEC will sell 150 MW during summer peak periods, 300 MW during summer off-peak periods, 25 MW during winter peak periods, and 225 MW during winter off-peak periods.

(2) PEC will sell (from its eastern BAA) 325 MW during summer peak periods and 500 MW during summer off-peak periods.

Weintraub stated that DEC and PEC have contracted to sell this capacity and energy to Cargill, EDF Trading North America, LLC, and Morgan Stanley. He said that the energy will be sold on a firm, liquidated damages basis, which means that the buyer must take the full contract amount in all hours, subject to interruption only on *force majeure* grounds. Energy prices will be based on pre-determined heat rates and the then-current gas prices.

Public Staff witness Hoard testified that the interim mitigation sales would begin upon close of the merger and continue until transmission facilities had been built and placed into service pursuant to the permanent mitigation plan. Hoard explained that the Supplemental Stipulation provided for the development of decrement riders to both DEC's and PEC's retail rates that will credit North Carolina customers for the revenue requirements of capacity sold under the interim mitigation sales. Hoard testified that the decrements were computed based on the costs of the generating facilities that are assumed to be used to provide the capacity for the mitigation sales, and that production optimization models were used to determine the mix of generators that would provide power for the mitigation sales. He stated that the annual capacity cost per MW for each kind of generation used in the computation included a rate of return on production plant, step-up transformer facilities, general plant, and associated rate base items, plus fixed operation and maintenance expenses, depreciation expense, and general taxes.

The Supplemental Stipulation requires the Applicants to file decrement riders with the Commission within 30 days of the merger close that would allocate away from DEC's and PEC's respective retail jurisdictions the capacity costs, including associated reserve margins, relative to the interim mitigation sales. The Supplemental Stipulation states that the total system costs of mitigation capacity to be allocated away from retail are $43,458,315 for DEC and $21,194,759 for PEC. Public Staff witness Hoard provided confidential supplemental Exhibits 1 and 2 detailing the calculation of these costs. The Supplemental Stipulation provides that, upon Commission approval, the riders are to remain in effect without any true ups until the interim mitigation sales end, which is estimated to be May 31, 2015.

Provision l.A(5) of the Supplemental Stipulation provides that DEC and PEC shall not seek to recover from their North Carolina retail customers any of the non-fuel variable operating and maintenance costs (O&M) associated with the interim mitigation sales. However, this provision does not articulate how such costs will be identified. In order to ensure that such costs are identified and removed from retail rates, the Commission finds that this provision requires clarifications. Therefore, the Commission concludes that it is necessary for DEC and PEC to make a compliance filing within 30 days of the merger closing explaining how and when these costs will be identified and removed from retail rates.

Provision l.A(6) of the Supplemental Stipulation provides additional protections for retail customers. It states that DEC and PEC shall not seek to recover from North Carolina retail customers any revenue shortfalls resulting from, or any costs associated with, the interim mitigation sales, including any negative capacity payments, any revenue deficiency resulting from energy revenues being less than the associated costs, and any payment of liquidated damages. Sales under the interim mitigation plan would continue until the permanent mitigation plan is in place. Applicants' witness Weintraub stated that, as part of its permanent mitigation plan, the Applicants also proposed a "stub mitigation" proposal which requires the set-aside of 25 MW of transmission capacity from the DEC BAA to the PEC east BAA. Only third parties that are unaffiliated with DEC or PEC would be able to reserve this transmission on a firm basis. The FERC Market Power Order required the Applicants to implement the stub mitigation plan in order to address wholesale market power issues in PEC's east BAA during summer off-peak periods.

Applicants witness Weintraub testified that the Applicants' permanent mitigation proposal required the construction of seven transmission projects in order to increase the ability of the DEC and PEC transmission systems to import power. Public Staff witness Hoard stated that the seven transmission projects would cost about $110 million, and that none of these seven projects is currently included in DEC's or PEC's transmission plans. Witness Hoard testified that under the Supplemental Stipulation, DEC and PEC may not request recovery of the costs of these facilities during the first five years following the close of the merger. According to Hoard, upon the expiration of this five-year period, DEC and PEC may request Commission approval for these costs in its retail rates if it can be shown that, absent the merger and the resulting mitigation requirements, the project is needed to provide adequate and reliable retail service and, at the time the request is made, the construction of the project and the incurrence of the associated costs would have been reasonable and prudent. In addition, Hoard testified that the utility must show that it intends to pursue recovery of the costs from its wholesale and firm transmission customers at the time of the request to the Commission.

In their June 18, 2012 supplemental comments, EDF, et al., expressed concerns regarding the retail cost impacts of the transmission projects that are required by the permanent mitigation plan. They stated that there is an inherent conflict between DEC's and PEC's assertions that there is currently no plan to build these projects, and the Supplemental Stipulation's provision allowing cost recovery after five years upon a showing that a project is needed for service adequacy and reliability. The Commission has considered EDF, et al.'s concerns and carefully reviewed provision B of the Supplemental Stipulation, which addresses the potential ratepayer impacts of the transmission projects that DEC and PEC have committed to build under the permanent mitigation plan. The Supplemental Stipulation specifies that any request by DEC or PEC to recover costs associated with a permanent transmission mitigation project in its North Carolina retail rates must be supported by evidence sufficient to show that, absent the merger and the resulting mitigation requirement, the project is needed to provide adequate and reliable retail service and, at the time the request is made, the construction of the project and the incurrence of the associated costs would have been reasonable and prudent. The Supplemental Stipulation provides further that, if this showing has been made, DEC and PEC may seek inclusion of only the net depreciated cost of the projects at the time of the request, and shall not request any deferral of any costs associated with the projects for ratemaking purposes. In addition, if, subsequent to the inclusion of the costs in North Carolina retail rates, DEC or PEC is not successful in incorporating the correct jurisdictional share of those costs into its wholesale transmission tariffs, then the corresponding proportionate share of such costs that had been approved for inclusion in retail rates shall be removed and refunds shall be made. The Commission finds that these provisions in the Supplemental Stipulation effectively protect ratepayers from inappropriate charges related to the mitigation-related transmission projects, with the exception of costs for the Greenville-Kinston Dupont line.

Weintraub testified that in addition to the seven projects discussed above, the Applicants are accelerating the in-service date of PEC's already planned Greenville-Kinston Dupont 230-kV line from 2017 to 2015. This line would not increase import capability, but is needed in order for four of the seven transmission expansion projects to be effective. Supplemental Stipulation provision B.(2) provides that "PEC may seek to include the costs associated with this line [Greenville-Kinston Dupont] in its North Carolina retail rates any time after the line is placed in service in accordance with normal ratemaking practices ...." The Commission finds that provision B.(2) does not adequately protect retail customers from the impacts of the Applicants' permanent wholesale market power mitigation. This facility had been scheduled to enter service in June of 2017. Due to the Applicants' need to mitigate their wholesale market power, the project is being accelerated by two years, but that acceleration is not needed in order to reliably serve retail customers. The Commission concludes that it is necessary to reject provision B.(2) of the Supplemental Stipulation and instead condition approval of the merger on PEC agreeing that it shall not seek to recover from its North Carolina retail customers any costs associated with the

Greenville-Kinston Dupont 230-kV line until the later of: (1) June 1, 2017, or (2) the actual in-service date of the line, absent a Commission order establishing that the facility is needed in order to reliably serve North Carolina customers at an earlier date.

In his supplemental testimony, Public Staff witness Hoard explained that the permanent transmission mitigation proposal also requires PEC to operate its Roxboro and Mayo units on a non-economic basis at full output to push back against American Electric Power/PJM Interconnection power flows in order to increase import capability into PEC. Hoard testified that DEC and PEC agreed not to seek recovery from retail ratepayers of the costs related to such dispatch of the plants out of merit order. Provision B.(3) of the Supplemental Stipulation requires PEC to include in its monthly fuel report the date, time and duration of dispatching the units out of merit order, and provide a detailed description of the dispatch order that would otherwise have occurred under the JDA. PEC must include the incremental difference in fuel, fuel-related, and variable O&M costs, on a joint dispatch basis, and the effect on the joint dispatch savings that are to be split between DEC and PEC.

In its Market Power Order, the FERC accepted the revised mitigation proposal, subject to numerous modifications, including the following:

(a) Applicants cannot use control over their transmission systems to thwart sales that they have entered into with Cargill, EDF Trading North America, LLC, and Morgan Stanley (collectively, mitigation sales).

(b) Applicants must not have any priority right over other potential buyers to re-purchase any of the energy and/or capacity sold by Applicants pursuant to the mitigation sales.

(c) For so long as the interim mitigation sales shall remain in place, Applicants must not enter into transactions with the counterparties to those sales except on a spot (day-ahead or shorter) basis.

(d) For the duration of the mitigation sales, Applicants must either limit the price they pay for new purchases of natural gas at Transco Zone 5 to the index price or replace Transco Zone 5 with Transco Zone 4 as the pricing zone.

(e) On each occasion when Applicants sell power under the mitigation sales agreements. Applicants must simultaneously post on their electronic bulletin boards the amount of power that was sold and for what duration.

(f) An Independent Monitor must monitor the mitigation sales for (a) hours in which buyers did not purchase the full amount of energy that Applicants are required to deliver; and (b) hours in which the buyer sells to either DEC or PEC in the DEC and/or PEC BAAs an amount of energy or capacity equal to or more than five percent of the amount of energy or capacity purchased by the buyer.

(g) The Independent Monitor must notify the FERC within three days if, in any hour and for any reason, the actual purchases under the mitigation sales are less than the quantities offered in those agreements.

(h) Applicants must notify the Independent Monitor within two business days, and the Independent Monitor must notify the FERC within three business days if a buyer sells to either DEC or PEC in the DEC and/or PEC BAAs an amount of energy or capacity equal to or more than five percent of the amount of such energy or capacity purchased by the buyer under the mitigation sales agreements. Such notification must include the date, hour, product name, quantity, and price of such sale(s) to Applicants, as well as the quantity and price of the energy or capacity purchased by the buyer from the Applicants during that/those same hour(s).

(i) The Independent Monitor must also: (a) document the quantities of energy and capacity purchased under the mitigation sales agreements; (b) document the amount of energy purchased by DEC and PEC from the counterparties to the mitigation sales agreements; and (c) document when a buyer under one of the agreements invokes *force majeure* because transmission from the delivery point(s) under the agreement to buyer's proposed ultimate sink is interrupted or is not available in the DEC and PEC BAAs and in BAAs or markets that are first-tier to DEC and PEC.

(j) Applicants must hold transmission and wholesale requirements customers harmless from costs that Applicants may incur under the mitigation sales for five years.

In their revised mitigation proposal that they filed with the FERC, the Applicants proposed to use Potomac Economics, Ltd (Potomac), as the Independent Monitor and attached an agreement between DEC and PEC and Potomac. In its June 13, 2012 comments, the Public Staff stated that the expansion of the Independent Monitor's duties in FERC's Market Power Order is sufficient to cause its fees to be a significant expense, particularly during the three-year period during which the interim mitigation sales are in place. The Public Staff also noted that the FERC has required the implementation of the Applicants' stub mitigation proposal. Therefore, the Public Staff recommended that the following additional condition be imposed to provide explicitly that Independent Monitor costs and stub mitigation costs cannot be recovered from DEC's and PEC's retail ratepayers:

> DEC and PEC shall not seek to recover from their North Carolina retail customers any costs associated with the Permanent Transmission Mitigation other than as provided in the Supplemental Stipulation, including, but not limited to, the costs and any revenue shortfalls associated with the implementation of the set-aside of firm transmission capacity as required by the Stub Mitigation measure approved in the FERC's Mitigation Order, and any of the fees paid to, or other costs associated with, Potomac Economics in its role as Independent Monitor.

In its June 13, 2012 comments, the Public Staff noted also that the other revisions to the interim mitigation measures required by FERC could increase the losses that DEC and PEC incur on the sale of capacity and energy pursuant to the interim mitigation sales, and perhaps cause DEC and PEC to incur increased costs for replacement power to serve retail customers. The

Public Staff stated that these risks are covered by the catch-all provision in Section I.A.(6) of the Supplemental Stipulation, which states:

> DEC and PEC shall not seek to recover from their North Carolina retail customers any revenue shortfalls resulting from, or any costs associated with, the Interim Mitigation Sales, including but not limited to any negative capacity payments, any revenue deficiency resulting from energy revenues being less than the associated costs and any payment of liquidated damages.

The Commission agrees with the Public Staff that the above-cited provision in the Supplemental Stipulation protects retail ratepayers as much as reasonably possible from risks of losses that DEC and PEC might incur relative to the interim mitigation sales.

The FERC made construction of all of the transmission upgrades described in the revised mitigation proposal an express condition of the Market Power Order and the merger itself. The FERC Market Power Order stated that if the Applicants fail to live up to their commitment to complete the transmission projects, it will require a further mitigation plan which might include virtual or physical divestitures. The FERC required the Applicants to inform it of any change in circumstances that would reflect a departure from the facts that the FERC relied on in approving the revised mitigation proposal and the merger.

In its June 13, 2012 comments, the Public Staff noted that while the Commission would have the opportunity to review any proposed mitigation plan before it is filed with the FERC, the foregoing reservations of jurisdiction by the FERC, and its stated intention to take further action, as necessary, warrant additional protections of the Commission's ability to shield ratepayers from any adverse impacts of any such subsequent action. The Public Staff recommended that the Commission approve a new condition as follows:

> To the extent the FERC imposes conditions, revisions, mitigation measures, and the like that expose retail ratepayers to additional costs, risks, or harms not covered by the 2011 Stipulation, including the Regulatory Conditions, or the Supplemental Stipulation, then the Applicants agree that, except as provided in Condition 2.2, they will not oppose the Commission taking further action as necessary to protect retail ratepayers from the effects of any such subsequent action.[1]

[1] Condition 2.2 is found on page 5 of the Regulatory Conditions that were attached as Appendix A and filed in corrected form on September 15, 2011. It reads as follows: "Other than as provided for, or explicitly prohibited, in these conditions, Duke Energy, DEC, PEC, and other Affiliates retain the right to challenge the lawfulness of any Commission order issued pursuant to or relating to these Regulatory Conditions on the basis that such order exceeds the Commission's statutory authority under North Carolina law or the other grounds listed in G.S. 62-94(b).

In addition, the Public Staff recommended that, given the possibility of further action by the FERC, DEC and PEC should be required to file promptly with the Commission and serve on the Public Staff all of the reports that are filed with the FERC by the Independent Monitor. The Commission agrees with the Public Staff and will, therefore, impose these additional conditions upon the Applicants.

In its June 18, 2012 comments, NC WARN stated that:

> ... provisions in the [FERC Market Power] Order significantly alter the benefits and costs associated with the merger ... the final FERC Order requires the extension of transmission lines connecting to the PJM regional transmission organization with the stated purpose of allowing competitive sales of electricity to eastern North Carolina. ... The FERC Order does not address the question about whether the approved transmission projects will then allow the new Duke Energy unrestricted access to sales outside its present service area into the PJM and Northeastern markets. This position is in line with FERC policy but does nothing to benefit the North Carolina ratepayers. If this is the case, Duke Energy will in all likelihood require new generation facilities to meet this potential demand, as it arguably did for its proposed sales to Orangeburg and other markets in South Carolina. Any cost savings through competition in eastern North Carolina would be more than offset by the costs of new generation facilities required for increased Duke Energy sales.

NC WARN argued that the need to build transmission projects in order to provide wholesale market power mitigation was one of several significant changes that had occurred since the public and evidentiary hearings were held in this proceeding. It requested a hearing to cross-examine Duke’s witnesses regarding these changes. On June 19, 2012, the Commission issued an Order scheduling a hearing to allow an opportunity for the introduction of the supplemental testimony of the Applicants’ and the Public Staff’s witnesses and to allow NC WARN to cross-examine the Applicants’ and the Public Staff’s witnesses, with such cross-examination limited to the supplemental testimony filed on May 15, 2012, and the further supplemental testimony filed on June 13, 2012.

At the June 25, 2012 hearing, the Applicants and the Public Staff introduced supplemental testimony and the Supplemental Stipulation, as amended. In addition, NC WARN cross examined Applicants witness Weintraub and Public Staff witness Hoard regarding their supplemental testimony.

Witness Weintraub testified that while it is likely that the transmission projects that are required to be built pursuant to the FERC Market Power Order will increase the amount of power that could be exported from the DEC and PEC east BAAs, he did not know by what amount. Weintraub testified that the projects were designed to increase the ability to import power, rather than the ability to export power.

Weintraub further testified that the changed circumstances referenced on page 9 of the Supplemental Stipulation were the delay in closing the merger beyond the original target closing date and the further reductions in natural gas prices. He stated that the reductions in natural gas prices and the effect of those reductions on DEC's and PEC's use of coal were the reasons for the agreement in the Supplemental Stipulation to potentially extend the period for receipt of the $650 million in savings by 18 months.

Public Staff witness Hoard testified that the changed circumstances were the delay in closing the merger beyond the original target closing date and the further reductions in natural gas prices. He further testified that the settlement agreements between the Applicants and parties other than the Public Staff were considered by the Public Staff in its negotiations of its settlement with the Applicants.

The Commission finds and concludes that the ratepayer protections provided by the Stipulation, and the Supplemental Stipulation, as amended, along with the additional provisions recommended by the Public Staff and those imposed by the Commission as discussed above, will protect retail customers as much as reasonably possible from costs and revenue shortfalls associated with the mitigation sales, the set-aside of firm transmission capacity as required by the "stub mitigation" measure and the transmission projects approved in FERC's Market Power Order. Further, the Commission finds and concludes that existing statutes and regulations are sufficient to address the alleged changed circumstances that NC WARN asserts could change the costs and benefits of the merger for retail customers if and when those changed circumstances present themselves and are ripe for decision-making. For example, in the event that DEC or PEC seeks authorization to construct additional electric generating facilities in North Carolina, such requests will be governed by G.S. 62-110.1, which requires DEC and PEC to first obtain from the Commission a certificate of public convenience and necessity upon a showing that such generating facilities are needed. Finally, the Commission notes that it is not the Commission's role to approve or disapprove those settlement agreements between the Applicants and parties other than the Public Staff. However, the Commission is not bound by the terms of those settlement agreements.

CONCLUSIONS OF LAW

The Commission concludes that the Stipulation, Regulatory Conditions, Code of Conduct, Supplemental Stipulation, as amended, guaranteed fuel and fuel-related savings, Applicants' contributions to various work force development, low-income assistance, environmental and charitable programs, and the potential for future merger cost savings for ratepayers are sufficient to ensure that: (1) the merger will have no adverse impact on the rates and service of DEC's and PEC's North Carolina retail ratepayers; (2) DEC's and PEC's North Carolina retail ratepayers are protected as much as reasonably possible from potential costs and risks resulting from the merger; and (3) there are sufficient benefits from the merger to offset the potential costs and risks. Therefore, the Commission further concludes that the proposed business combination between Duke and Progress is justified by the public convenience and necessity.

Accordingly, the Commission finds good cause to approve Duke's and Progress' application to enter into a business combination transaction, provided that Duke and Progress shall file a statement in this docket notifying the Commission that they accept and agree to all the terms, conditions and provisions of this Order, as well as the Commission-approved Regulatory Conditions and Code of Conduct.

IT IS, THEREFORE, ORDERED as follows:

1. That the application of Duke and Progress pursuant to G.S. 62-111(a) to engage in a business combination transaction shall be, and is hereby, approved, subject to the provisions of this Order and the Regulatory Conditions and Code of Conduct attached hereto and incorporated herein.

2. That the request of Duke and Progress to nullify PEC's Regulatory Conditions and Code of Conduct, as revised and approved in Docket No. E-2, Sub 844, shall be, and is hereby, granted, subject to the merger being consummated and the Regulatory Conditions and Code of Conduct approved herein becoming effective, whereupon DEC's Regulatory Conditions and Code of Conduct, as approved in Docket No. E-7, Sub 795, also shall be nullified.

3. That DEC's and PEC's North Carolina retail customers shall be guaranteed receipt of their allocable share of $650 million in fuel and fuel-related cost savings resulting from the merger, as discussed herein. The percentages of such savings allocated to the North Carolina retail jurisdiction shall be consistent with current practice. Further, if the fuel and fuel-related savings achieved by DEC and PEC exceed the guaranteed $650 million after the merger, then North Carolina ratepayers shall receive their allocable share of the additional savings.

4. That within 30 days from the close of the merger DEC and PEC shall file for a decrement in fuel rates for North Carolina retail customers to remain in effect until rates are adjusted in their next fuel cost proceedings. These reductions shall be based upon the projected fuel and fuel-related savings for Year 1 as set forth in Exhibits 4 (JDA) and 5 (Fuel Synergies Review) to the Merger Application. The initial rate reduction shall be based on the pro rata amount of Year 1 savings to be achieved during the period between the close of the merger and the effective date of the rate changes in DEC's and PEC's next fuel cost proceedings.

5. That a new decrement for fuel savings shall be determined at the time of each respective fuel cost proceeding during the guaranteed savings period and shall be implemented at the time new rates in those proceedings take effect. If at the end of the guaranteed savings period DEC's and PEC's respective North Carolina retail customers have not received their allocable shares of the $650 million of guaranteed savings, the remaining amount shall be reflected as an adjustment in DEC's and PEC's first fuel cost proceedings following the end of the guaranteed savings period.

6. That the methods of determining fuel and fuel-related cost savings resulting from the merger shall be subject to ongoing review, and shall be refined and revised as allowed by further Commission order based on experience as savings are realized.

7. That DEC and PEC shall file with their fuel reports required pursuant to Commission Rule R8-52 monthly reports of tracked fuel savings on the bases of (a) total system, (b) DEC, (c) DEC North Carolina retail, (d) PEC, and (e) PEC North Carolina retail.

8. That within 30 days from the close of the merger DEC and PEC shall file the decrement riders as provided for under the Supplemental Stipulation that will allocate away from DEC's and PEC's retail jurisdictions the capacity costs, including reserve margins, relative to the interim mitigation sales.

9. That within 30 days from the close of the merger DEC and PEC shall file with the Commission an explanation of how and when non-fuel variable O&M costs associated with interim mitigation sales will be identified and removed from retail sales.

10. That provision B(2) of the Supplemental Stipulation is hereby rejected, and PEC shall not seek to recover from retail customers any costs associated with the Greenville-Kinston Dupont 230-kV line until the later of: (1) June 1, 2017, or (2) the actual in-service date of the line, absent a Commission order establishing that the facility is needed in order to reliably serve North Carolina customers at an earlier date.

11. That PEC and DEC shall timely serve on the Public Staff and the Commission all reports of the Independent Monitor that are filed with the FERC.

12. That DEC and PEC shall not seek to recover from their North Carolina retail customers any costs associated with the permanent transmission mitigation other than as provided in the Supplemental Stipulation, including, but not limited to, the costs and any revenue shortfalls associated with the implementation of the set-aside of firm transmission capacity as required by the Stub Mitigation measure required by FERC's Market Power Order, and any of the fees paid to, or other costs associated with, Potomac Economics in its role as Independent Monitor.

13. That approval of the merger is conditioned upon the following: to the extent the FERC imposes conditions, revisions, mitigation measures and the like that expose retail ratepayers to additional costs, risks, or harms not covered by the Stipulation, Regulatory Conditions, or the Supplemental Stipulation, as amended, then the Applicants agree that, except as provided in Condition 2.2, they will not oppose the Commission taking further action as necessary to protect retail ratepayers from the effects of any such subsequent FERC action.

14. That DEC and PEC shall provide annual community support and charitable contributions in North Carolina for four years from the close of the merger at a level no less than $9.2 million and $7.28 million, respectively, based on the average of each company's annual contributions over the past five years (2006 through 2010).

15. That DEC and PEC shall contribute a total of $15 million during the first year following the close of the merger for workforce development and low-income energy assistance, as well as an additional $2 million to NC GreenPower, as fully detailed in this Order.

16. That Progress Energy and PEC shall maintain a significant corporate and utility presence in downtown Raleigh following the close of the merger.

17. That PEC's generation dispatch function and PEC's employees engaged in the generation dispatch function shall remain located in PEC's Energy Control Center in Raleigh until further order of the Commission.

18. That for purposes of distributing the costs of services provided between and among their affiliates, PEC shall continue to use direct charging, and all PEC employees shall continue to use positive time reporting. DEC shall increase the amount of such costs that are directly charged and shall complete the transition to direct charging and positive time reporting within two years following the close of the merger. DEC shall file semi-annual reports with the Commission detailing its progress in implementing these practices, with the first report due six months from the close of the merger.

19. That merger and merger-related costs shall be treated as follows:

(a) Direct expenses associated with costs to achieve the merger, including change-in-control payments made to terminated executives, 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 DEC’s and PEC’s cost of service for retail ratemaking purposes.

(b) DEC and PEC may request recovery through depreciation or amortization of capital costs associated with achieving merger savings, such as system integration costs and the adoption of best practices, including information technology, provided that such costs are incurred no later than three years from the close of the merger and only the net depreciated costs of such system integration projects at the time the request is made may be included and no request for deferrals of these costs may be made. However, this limitation shall not apply to DEC's capital costs associated with post-merger coal blending.

(c) In order to justify such cost recovery, DEC and PEC must show that the capital costs described in subsection (b) above resulted in quantifiable cost savings to their respective North Carolina retail ratepayers greater than the revenue requirement effect of the inclusion of these costs in rate base.

(d) DEC's and PEC's merger-related severance costs shall be excluded from DEC's and PEC's cost of service for retail ratemaking purposes.

20. That the following shall be filed in accordance with and as provided in the Regulatory Conditions, unless otherwise ordered by the Commission: any and all affiliate agreements contemplated to be used upon the close of the merger; the lists of services proposed to be taken pursuant to each such service agreement; and the process by which all costs shall be accumulated, directly charged, assigned, or allocated and any proposed allocation ratios. Each service agreement or other affiliate agreement entered into by DEC and PEC following the close of the merger shall reference the specific Regulatory Conditions and Code of Conduct provisions that are relevant to such agreements.

21. That the JDA shall be, and is hereby, approved. With respect to the monitoring and implementation of the JDA, DEC and PEC shall do the following:

(a) Provide to the Public Staff and file with the Commission, prior to the implementation of the JDA, a detailed description of the production cost model that will be used, including the algorithms, assumptions, and inputs to the model, to simulate the production costs of DEC and PEC under the stand-alone utility case;

(b) Verify the accuracy of the production cost model in estimating stand-alone utility production costs by benchmarking the model against a recent historical period (e.g., 2009 - 2011) in which DEC and PEC dispatched their generation on a stand-alone basis;

(c) Notify the Commission and the Public Staff at least quarterly when significant changes have been made to algorithms, assumptions and inputs to the model and provide an explanation justifying those changes; and

(d) File with the Commission and provide to the Public Staff all the information necessary to conduct an audit (i.e., spot check) of the model inputs and outputs as often as monthly, until the utilities and the Public Staff have gained experience with the model, and at least quarterly thereafter.

22. That DEC, PEC and the Public Staff will work with other interested parties to propose within 90 days after the close of the merger a Commission rulemaking to standardize the indices used to measure and report electric utility service quality.

23. That within 30 days of this Order the Applicants and Public Staff shall make a joint compliance filing that provides the Commission with one set of all the Regulatory Conditions, the final Code of Conduct and a final version of the Stipulation, including terms of the Supplemental Stipulation, as amended.

ISSUED BY ORDER OF THE COMMISSION.
This the _29th_ day of _June_, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

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APPENDIX A

DOCKET NO. E-2, SUB 998

DOCKET NO. E-7, SUB 986

REGULATORY CONDITIONS

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REGULATORY CONDITIONS

These Regulatory Conditions set forth commitments made by Duke Energy and Progress Energy, and their public utility subsidiaries, Duke Energy Carolinas, LLC (DEC), and Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC), as a precondition of approval of the application by Duke Energy and Progress Energy pursuant to G.S. 62-111(a) for authority to engage in their proposed business combination transaction. These Regulatory Conditions, which become effective only upon closing of the Merger, shall apply jointly and severally to Duke Energy and Progress Energy, as well as jointly and severally to DEC and PEC, and shall be interpreted in the manner that most effectively fulfills the Commission’s purposes as set forth in the preamble to Section II of these Regulatory Conditions.

SECTION I
DEFINITIONS

For the purposes of these Regulatory Conditions, capitalized terms shall have the meanings set forth below. If a capitalized term is not defined below, it shall have the meaning provided elsewhere in this document or as commonly used in the electric utility industry.

Affiliate: Duke Energy and any business entity of which ten percent (10%) or more is owned or controlled, directly or indirectly, by Duke Energy. For purposes of these Regulatory Conditions, Duke Energy and each business entity so controlled by it are considered to be Affiliates of DEC and PEC, and DEC and PEC are considered to be Affiliates of each other.

Affiliate Contract: Any contract or agreement (a) between and among any of the Affiliates if such contracts are reasonably likely to have an Effect on DEC's or PEC's Rates or Service, or (b) to which both DEC and any Affiliate are parties or PEC and any Affiliate are parties, including contracts with proposed Affiliates. Such contracts and agreements include, but are not limited to, service, operating, interchange, pooling, and wholesale power sales agreements and agreements involving financings and asset transfers and sales.

Catawba Joint Owners: The North Carolina Electric Membership Corporation, North Carolina Municipal Power Agency No. 1, and Piedmont Municipal Power Agency. For purposes of these Regulatory Conditions, DEC is not included in the definition of Catawba Joint Owners.

Code of Conduct: The minimum guidelines and rules approved by the Commission that govern the relationships, activities, and transactions between and among the public utility operations of DEC and PEC, Duke Energy, the other Affiliates of DEC and PEC, and the Nonpublic Utility Operations of DEC and PEC, as those guidelines and rules may be amended by the Commission from time to time.

Commission: The North Carolina Utilities Commission.

Customer: Any retail electric customer of DEC or PEC in North Carolina.

DEBS: Duke Energy Business Services, LLC, and its successors, which is a service company Affiliate that provides Shared Services to DEC, PEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC or PEC, singly or in any combination.

DEC: Duke Energy Carolinas, LLC, the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Electric Services within DEC's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Duke Energy: Duke Energy Corporation, which is the current holding company parent of DEC and PEC, and any successor company.

Effect on DEC's or PEC's Rates or Service: When used with reference to the consequences to DEC or PEC of actions or transactions involving an Affiliate or Nonpublic Utility Operation, this phrase has the same meaning that it has when the Commission interprets G.S. 62-3(23)(c) with respect to the affiliation covered therein.

Electric Services: Commission-regulated electric power generation, transmission, distribution, delivery, or sales, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, and standby service.

Federal Law: Any federal statute or legislation, or any regulation, order, decision, rule or requirement promulgated or issued by an agency or department of the federal government.

FERC: The Federal Energy Regulatory Commission.

Fully Distributed Cost: All direct and indirect costs, including overheads and an appropriate cost of capital, incurred in providing goods or services to another business entity; provided, however, that (a) for each good and service supplied by or from DEC or PEC, the return on common equity utilized in determining the appropriate cost of capital shall equal the return on common equity authorized by the Commission in the supplying utility's most recent general rate case proceeding, (b) for each good and service supplied to DEC or PEC, the appropriate cost of capital shall not exceed the overall cost of capital authorized in the supplying utility's most recent general rate case proceeding; and (c) for each good and service supplied by or from DEC and PEC to each other, the return on common equity utilized in determining the appropriate cost of capital shall not exceed the lower of the returns on common equity authorized by the Commission in DEC's and PEC's most recent general rate case proceedings.

JDA: Joint Dispatch Agreement, which is the agreement as filed with the Commission on April 1, 2011, and as revised and filed on April 4, 2011, in Docket Nos. E-7, Sub 980, and E-2, Sub 995, and allowed by the Commission to be filed with the FERC, by Order dated April 4, 2011, and as further revised and filed on June 22, 2011, and allowed to be filed with the FERC by Order dated July 11, 2011, in Docket Nos. E-7, Sub 986, and E-2, Sub 998.

Market Value: The price at which property, goods, and services would change hands in an arm's length transaction between a buyer and a seller without any compulsion to engage in a transaction, and both having reasonable knowledge of the relevant facts.

Merger: All transactions contemplated by the Agreement and Plan of Merger between Duke Energy and Progress Energy.

Native Load Priority: Power supply service being provided or electricity otherwise being sold with a priority of service equivalent to that planned for and provided by DEC or PEC to their respective Retail Native Load Customers.

Non-Native Load Sales: DEC's or PEC's sales of energy at wholesale, not including transactions between DEC and PEC pursuant to the JDA and not including service to customers served at Native Load Priority.

Nonpublic Utility Operations: All business operations engaged in by DEC or PEC involving activities (including the sales of goods or services) that are not regulated by the Commission, or otherwise subject to public utility regulation at the state or federal level.

Non-Utility Affiliate: Any Affiliate, including DEBS and PESC, other than a Utility Affiliate, DEC, or PEC.

PEC: Progress Energy Carolinas, Inc., the business entity wholly owned by Duke Energy that holds the franchises granted by the Commission to provide Electric Services within the North Carolina service territory of PEC and that engages in public utility operations, as defined in G.S. 62-3(23) within the State of North Carolina.

PESC: Progress Energy Services Company, and its successors, which is a service company Affiliate that provides Shared Services to PEC, DEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC or PEC, individually or in combination.

Progress Energy: Progress Energy, Inc., which is the former holding company parent of PEC, and which became a subsidiary of Duke Energy after the close of the Merger, and any successors.

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

PUHCA 2005: The Public Utility Holding Company Act of 2005.

Purchased Power Resources: Purchases of energy by DEC or PEC at wholesale from sellers other than each other, the contract terms for which are one year or longer.

Retail Native Load Customers: The captive retail Customers of DEC and PEC in North Carolina for which DEC and PEC have the obligation under North Carolina law to engage in long-term planning and to supply all Electric Services, including installing or contracting for capacity, if needed, to reliably meet their electricity needs.

Retained Earnings: The retained earnings currently required to be listed on page 112, line 11, of the pre-Merger DEC FERC Form 1 and the pre-Merger PEC FERC Form 1.

Shared Services: The services that meet the requirements of these Regulatory Conditions and that the Commission has explicitly authorized DEC and PEC to take from DEBS or PESC pursuant to a service agreement (a) filed with the Commission pursuant to G.S. 62-153(b), thus requiring acceptance and authorization by the Commission, and (b) subject to all other applicable provisions of North Carolina law, the rules and orders of the Commission, and these Regulatory Conditions.

Utility Affiliates: The regulated public utility operations of Duke Energy Indiana, Inc. (Duke Indiana), Duke Energy Kentucky, Inc. (Duke Kentucky), and Florida Power Corporation, d/b/a Progress Energy Florida (PEF), and the regulated transmission and distribution operations of Duke Energy Ohio, Inc. (Duke Ohio).

SECTION II
AUTHORITY, SCOPE, AND EFFECT

These Regulatory Conditions are based on the general power and authority granted to the Commission in Chapter 62 of the North Carolina General Statutes to control and supervise the public utilities of the State. The Regulatory Conditions (a) constitute specific exercises of the Commission's authority, (b) provide mechanisms that enable the Commission to determine in advance the extent of its authority and jurisdiction over proposed activities of, and transactions involving, DEC, PEC, Duke Energy, other Affiliates or Nonpublic Utility Operations, and (c) protect the Commission's jurisdiction from federal preemption and its effects. The purpose of these Regulatory Conditions is to ensure that DEC's and PEC's Retail Native Load 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. These Regulatory Conditions are not intended to impose legal obligations on entities in which Duke Energy does not directly or indirectly have a controlling voting interest, or to affect any rights of any party to participate in subsequent proceedings.

2.1 Waiver of Certain Federal Rights. Pursuant to these conditions, DEC, PEC, Duke Energy, and other Affiliates waive certain of their federal rights as specified in these Regulatory Conditions, but do not otherwise agree that the Commission has authority other than as provided for in Chapter 62.

2.2 Limited Right to Challenge Commission Orders. Other than as provided for, or explicitly prohibited, in these conditions, Duke Energy, DEC, PEC, and other Affiliates retain the right to challenge the lawfulness of any Commission order issued pursuant to or relating to these Regulatory Conditions on the basis that such order exceeds the Commission's statutory authority under North Carolina law or the other grounds listed in G.S. 62-94(b).

2.3 Waiver Request. DEC, PEC, Duke Energy, and other Affiliates may seek a waiver of any aspect of these Regulatory Conditions by filing a request with the Commission showing that exigent circumstances in a particular case justify such a waiver.

SECTION III
PROTECTION FROM PREEMPTION

The following Regulatory Conditions are intended to protect the jurisdiction of the Commission against the risk of federal preemption as a result of the Merger, including risks related to agreements and transactions between and among DEC, PEC, and any of their Affiliates; financing transactions involving Duke Energy, DEC, or PEC, and any other Affiliate; the ownership, use, and disposition of assets by DEC or PEC; participation in the wholesale market by DEC or PEC; and filings with federal regulatory agencies.

ELECTRIC -- CONTRACTS/AGREEMENTS

3.1 Transactions between DEC, PEC, and Other Affiliates; Affiliate Contract Provisions; Advance Notice of Affiliate Contracts to Be Filed with the FERC; Annual Certification.

(a) Neither DEC nor PEC shall engage in any transactions with an Affiliate or proposed Affiliate without first filing the proposed Affiliate Contract with the Commission that memorializes any such dealings and taking such actions and obtaining from the Commission such decisions as are required under North Carolina law. DEC and PEC shall submit each proposed Affiliate Contract to the Public Staff for informal review at least ten days before filing it with the Commission. No formal advance notice is required for agreements that DEC or PEC intends to file pursuant to G.S. 62-153 unless the agreements are to be filed with the FERC, in which case subsection (c) applies.

(b) All Affiliate Contracts to which DEC or PEC is a party shall contain the following provisions:

(ii) DEC's or PEC's participation in the agreement is voluntary, DEC or PEC is not obligated to take or provide services or make any purchases or sales pursuant the agreement, and DEC or PEC may elect to discontinue its participation in the agreement at its election after giving any required notice;

(iii) DEC or PEC may not make or incur a charge under the agreement except in accordance with North Carolina law and the rules, regulations and orders of the Commission promulgated thereunder;

(iv) DEC or PEC may not seek to reflect in rates any (A) costs incurred under the agreement exceeding the amount allowed by the Commission or (B) revenue level earned under the agreement less than the amount imputed by the Commission; and

(iv) Neither DEC nor PEC shall assert in any forum – whether judicial, administrative, federal, state, local or otherwise – either on its own initiative or in support of another entity's assertions, that the Commission's authority to assign, allocate, impute, make pro-forma adjustments to, or disallow revenues and costs for retail ratemaking and regulatory accounting and reporting purposes is, in whole or in part, (A) preempted by Federal Law or (B) not within the Commission's power, authority or jurisdiction; DEC and PEC will bear the full risk of any preemptive effects of Federal Law with respect to the agreement.

(c) In order to enable the Commission to exercise its jurisdiction over a proposed Affiliate Contract, a contract with a proposed Affiliate, or an amendment to an existing Affiliate Contract that involves costs that will be assigned to DEC or PEC and that is required or intended to be filed with the FERC, the following procedures shall apply:

(i) DEC or PEC shall file advance notice and a copy of the proposed Affiliate Contract, a contract with a proposed Affiliate, or an amendment to an existing Affiliate Contract with the Commission at least 30 days prior to a filing with the FERC. A copy shall be provided to the Public Staff at the time of the filing. The provisions of Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition.

(ii) If an objection to DEC or PEC proceeding with the filing with the FERC is filed pursuant this Regulatory Condition, the proposed filing shall not be made with the FERC until the Commission issues an order resolving the objection.

(iii) Filings of advance notices and copies of proposed Affiliate Contracts, a contract with a proposed Affiliate, and amendments to existing Affiliate Contracts pursuant to this subsection shall be in addition to filings required by G.S. 62-153, and the burden of proof as to those filings shall be as provided by statute.

(d) Both DEC and PEC shall certify in a filing with the Commission that neither DEC, PEC, Duke Energy, any other Affiliate, nor any Nonpublic Utility Operation has made any filing with the FERC or any other federal regulatory agency inconsistent with the foregoing. Such certification shall be repeated annually on the anniversary of the first certification.

3.2 Financing Transactions Involving DEC, PEC, Duke Energy, or Other Affiliates.

(a) With respect to any financing transaction between DEC or PEC and Duke Energy, or any one or more of DEC's or PEC's other Affiliates, any contract memorializing such transaction shall expressly provide that DEC or PEC shall not enter into any such financing transaction except in accordance with North Carolina law and the rules, regulations and orders of the Commission promulgated thereunder; and

(b) With respect to any financing transaction (i) between and among any of the Affiliates if such contracts are reasonably likely to have an Effect on DEC's or PEC's Rates or Service, or (ii) between DEC and PEC or between DEC or PEC and any other Affiliate, any contract memorializing such transaction shall expressly provide that DEC and/or PEC shall not include the effects of any capital structure or debt or equity costs associated with such financing transaction in its North Carolina retail cost of service or rates except as allowed by the Commission.

3.3 Ownership and Control of Assets Used by DEC and PEC to Supply Electric Power to North Carolina Retail Customers; Transfer of Ownership or Control.

(a) DEC and PEC shall each own and control all assets or portions of assets used for the generation, transmission, and distribution of electric power to their respective North Carolina retail Customers (with the exception of assets solely used to provide power purchased by DEC or PEC at wholesale).

(b) With respect to the transfer by DEC or PEC to any entity, affiliated or not, of the control of, operational responsibility for, or ownership of such assets with a gross book value in excess of ten million dollars ($10 million), DEC or PEC shall provide written notice to the Commission at least 30 days in advance of the proposed transfer. The provisions of Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition.

(c) Any contract memorializing such a transfer shall include the following language:

(i) DEC or PEC may not commit to or carry out the transfer except in accordance with applicable law, and the rules, regulations and orders of the Commission promulgated thereunder; and

(ii) DEC or PEC may not include in its North Carolina retail cost of service or rates the value of the transfer, whether or not subject to federal law, except as allowed by the Commission in accordance with North Carolina law.

(d) Any application filed with the FERC in connection with any transfer of control, operational responsibility, or ownership that involves or potentially affects DEC or PEC shall include the language set forth in subdivisions (c)(i) and (ii), above, and shall request that the FERC explicitly provide in any order approving the application that its approval in no way affects the right of the Commission to review the value of such transfer and to establish the value of the asset transfer for purposes of determining the rates for services rendered to DEC's and PEC’s North Carolina retail Customers.

3.4 <u>Purchases and Sales of Electricity between DEC, PEC, Duke Energy, Other Affiliates, or Nonpublic Utility Operations</u>. Subject to additional restrictions set forth in the Code of Conduct, neither DEC nor PEC shall purchase electricity (or related ancillary services) from Duke Energy, another Affiliate, or a Nonpublic Utility Operation under circumstances where the total all-in costs, including generation, transmission, ancillary costs, distribution, taxes and fees, and delivery point costs, incurred (whether directly or through allocation), based on information known, anticipated, or reasonably available at the time of purchase, exceed fair Market Value for comparable service, nor shall DEC or PEC sell electricity (or related ancillary services) to Duke Energy, another Affiliate, or a Nonpublic Utility Operation for less than fair Market Value; provided, however, that such restrictions shall not apply to emergency transactions. This condition shall not apply to transactions between DEC and PEC that are governed by the JDA.

3.5 Least Cost Integrated Resource Planning and Resource Adequacy. DEC and PEC shall each retain the obligation to pursue least cost integrated resource planning for their respective Retail Native Load Customers and remain responsible for their own resource adequacy subject to Commission oversight in accordance with North Carolina law. DEC and PEC shall determine the appropriate self-built or purchased power resources to be used to provide future generating capacity and energy to their respective Retail Native Load Customers, including the siting considered appropriate for such resources, on the basis of the benefits and costs of such siting and resources to those Retail Native Load Customers.

3.6 Priority of Service.

(a) The planning and joint dispatch of DEC's system generation and Purchased Power Resources shall ensure that DEC's Retail Native Load Customers receive the benefits of that generation and those resources, including priority of service, to meet their electricity needs consistent with the JDA. DEC shall continue to serve its Retail Native Load Customers with the lowest-cost power it can reasonably generate or obtain as Purchase Power Resources before making power available for sales to customers that are not entitled to the same level of priority as Retail Native Load Customers.

(b) The planning and joint dispatch of PEC's system generation and Purchase Power Resources shall ensure that PEC's Retail Native Load Customers receive the benefits of that generation and those resources, including priority of service, to meet their electricity needs consistent with the JDA. PEC shall continue to serve its Retail Native Load Customers with the lowest-cost power it can reasonably generate or obtain as Purchase Power Resources before making power available for sales to customers that are not entitled to the same level of priority as Retail Native Load Customers.

3.7 Wholesale Power Contracts Granting Native Load Priority.

(a) DEC is not required to file an advance notice with the Commission or receive its approval prior to entering into wholesale power contracts that grant Native Load Priority to the following historically served customers: the City of Concord, North Carolina; the City of Kings Mountain, North Carolina; the Town of Dallas, North Carolina; the Town of Forest City, North Carolina; Lockhart Power Company; the Public Works Commission of the Town of Due West, South Carolina; the Town of Prosperity, South Carolina; the City of Greenwood, South Carolina; the Town of Highlands; North Carolina; Western Carolina University (WCU); the electric membership cooperatives (EMCs) within DEC's control area; North Carolina Municipal Power Agency No. 1; Piedmont Municipal Power Agency; New River Light & Power Company; and the South Carolina distribution cooperatives historically served by Saluda River Electric Cooperative, Inc., and currently served by Central Electric Power Cooperative, Inc. (which are Blue Ridge Electric Cooperative, Inc., Broad River Electric Cooperative Inc., Laurens Electric Cooperative, Inc., Little River Electric Cooperative, Inc., and York Electric Cooperative, Inc.). Subject to the conditions set out in Regulatory Condition 3.9, the retail native loads of these historically served wholesale customers shall be considered DEC's Retail Native Load Customers for purposes of Regulatory Conditions 3.5, 3.6, and 4.5; provided, however, that this subsection applies only to the same types of supplemental load and backstand requirements services that were historically provided to the Catawba Joint Owners under the Catawba Interconnection Agreements between DEC and the Catawba Joint Owners prior to 2001, which, for the North Carolina Electric Membership Corporation, only includes the EMCs within DEC's control area.

(b) PEC is not required to file an advance notice with the Commission or receive its approval prior to entering into wholesale power contracts that grant Native Load Priority to the Public Works Commission of the City of Fayetteville, North Carolina; the Town of Waynesville, North Carolina; the City of Camden, South Carolina; the French Broad Electric Membership Corporation; the North Carolina Eastern Municipal Power Agency; the electric membership cooperatives (EMCs) within PEC’s control area, whether served through the North Carolina Electric Membership Corporation (NCEMC) or individually; the Town of Black Creek, North Carolina; the Town of Lucama, North Carolina; the Town of Stantonsburg, North Carolina; the Town of Sharpsburg, North Carolina; and the Town of Winterville, North Carolina. Subject to the conditions set out in Regulatory Condition 3.9, the retail native loads of these historically served wholesale customers shall be considered PEC’s Retail Native Load Customers for purposes of Regulatory Conditions 3.5, 3.6, and 4.5.

(c) Before either DEC or PEC executes any contract that grants Native Load Priority to a wholesale customer (other than as set forth in subdivisions (a) and (b) above) or to one or more retail customers of another entity, it must provide the Commission with at least 30 days' written advance notice of its intent to grant Native Load Priority and to treat the retail native load of a proposed wholesale customer as if it were DEC's or PEC’s retail native load pursuant to Regulatory Conditions 3.5, 3.6, and 4.5. The provisions set forth in Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition.

3.8 Other Wholesale Contracts. To the extent that DEC's or PEC’s proposed wholesale power contracts or other sales of energy and capacity are at less than Native Load Priority, then no advance notice is required and no approval by the Commission is needed.

3.9 Additional Provisions Regarding Wholesale Contracts Entered into by DEC or PEC as Sellers.

(a) The Commission retains the right to assign, allocate, impute, and make pro-forma adjustments with respect to the revenues and costs associated with both DEC's or

PEC's wholesale contracts for retail ratemaking and regulatory accounting and reporting purposes.

(b) Entry into wholesale contracts that grant Native Load Priority or otherwise obligate DEC or PEC to construct generating facilities or make commitments to purchase capacity and energy to meet those contractual commitments constitutes acceptance by DEC, PEC, Duke Energy, and other Affiliates or Nonpublic Utility Operations thereof of the risks that investments in generating facilities or commitments to purchase capacity and energy to meet such contractual commitments and maintain an adequate reserve margin throughout the term of such contracts may become uneconomic sunk costs that are not recoverable from DEC's or PEC's respective Retail Native Load Customers. In a future Commission retail proceeding in which cost recovery is at issue, neither DEC nor PEC shall claim that it does not bear this risk, and both DEC and PEC shall acknowledge that the Commission retains full authority under Chapter 62 to disallow such costs as not used and useful and to allocate, impute, or assign such costs away from Retail Native Load Customers. For purposes of this condition, capacity will be considered used and useful and not excess capacity to the extent the Commission determines such capacity is needed by DEC or PEC to meet the expected peak loads of DEC's or PEC's respective Retail Native Load Customers in the near term future plus a reserve margin comparable to that currently being used or otherwise considered appropriate by the Commission. Neither DEC, PEC, Duke Energy, nor any other Affiliate shall assert in any forum – whether judicial, administrative, federal, state, local or otherwise – either on its own initiative or in support of any other entity's assertions that the Commission is preempted from taking the actions contemplated in this subsection.

(c) Neither DEC, PEC, Duke Energy, or other Affiliate shall assert in any forum – whether judicial, administrative, federal, state, local or otherwise – either on its own initiative or in support of any other entity's assertions that (i) transactions entered into pursuant to DEC's or PEC's cost- or market-based rate authority or (ii) the filing with, or acceptance for filing by, the FERC of any wholesale power contract to which either is a party establishes or implies a cost allocation methodology that is binding on the Commission, requires the pass-through of any costs or revenues under the filed rate doctrine, or preempts the Commission's authority to assign, allocate, impute, make pro-forma adjustments to, or disallow the revenues and costs associated with, DEC's or PEC's wholesale contracts for retail ratemaking and regulatory accounting and reporting purposes.

(d) Neither DEC, PEC, Duke Energy, or other Affiliate shall assert in any forum – whether judicial, administrative, federal, state, local or otherwise – either on its own initiative or in support of any other entity's assertions that the exercise of authority by the Commission to assign, allocate, impute, make pro-forma adjustments to, or disallow the costs and revenues associated with DEC's or PEC's wholesale contracts for retail ratemaking and regulatory accounting and reporting purposes in itself constitutes an undue burden on interstate commerce or otherwise violates the Commerce Clause of the United States Constitution. However, DEC and PEC retain the right to argue that a specific exercise of authority by the Commission violates the Commerce Clause based upon specific evidence of undue interference with interstate commerce.

(e) Except as provided in the foregoing conditions, DEC and PEC retain the right to challenge the lawfulness of any order issued by the Commission in connection with the assignment, allocation, imputation, pro-forma adjustments to, or disallowances of the revenues and costs associated with DEC's or PEC's wholesale contracts for retail ratemaking and regulatory accounting and reporting purposes on any other grounds, including but not limited to the right outlined in G.S. 62-94(b).

3.10 Other Protections.

(a) Neither DEC, PEC, Duke Energy, another Affiliate, nor a Nonpublic Utility Operation shall assert in any forum – whether judicial, administrative, federal, state, local or otherwise – either on its own initiative or in support of any other entity's assertions that approval by the FERC of market-based rates, transfers of generating facilities, or any matter that involves Affiliates in any way preempts the Commission's authority to determine the reasonableness or prudence of DEC's or PEC's decisions with respect to supply-side resources, demand-side management, or any other aspect of resource adequacy.

(b) No agreement shall be entered into, nor shall any filing be made with the FERC, by or on behalf of DEC or PEC, that (i) commits DEC or PEC to, or involves either of them in, joint planning, coordination, dispatch or operation of generation, transmission, or distribution facilities with each other or with one or more other Affiliates, or (ii) otherwise alters DEC's or PEC's obligations with respect to these Regulatory Conditions, absent explicit approval of the Commission.

(c) DEC, PEC, Duke Energy, the other Affiliates, and the Nonpublic Utility Operations shall file notice with the Commission at least 30 days prior to filing with the FERC any agreement, tariff, or other document or any proposed amendments, modifications, or supplements to any such document that has the potential to (i) affect DEC's or PEC's retail cost of service for system power supply resources or transmission system; (ii) reduce the Commission's jurisdiction with respect to transmission planning or any other aspect of the Commission's planning authority; (iii) be interpreted as involving DEC or PEC in joint planning, coordination, dispatch, or operation of generation or transmission facilities with one or more Affiliates; or (iv) otherwise have an Effect on DEC's or PEC's Rates or Service. The provisions set forth in Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition; provided, however, that, to the extent the filing with the FERC is not to be made by DEC or PEC, the advance notice procedures shall be for the purpose of a determination by the Commission as to whether the filing is reasonably likely to have an Effect on DEC's or PEC's Rates or Service.

(d) Any contract or filing regarding DEC's or PEC's membership in or withdrawal from an RTO or comparable entity must be contingent upon state regulatory approval.

(e) Consistent with G.S. 62-153, DEC and PEC shall obtain prior approval of any proposed substantive revisions to any Affiliate agreement to which either of them is a party.

(f) DEC and PEC shall obtain Commission approval before either DEBS or PESC is sold, transferred, merged with any other entities, has any ownership interest therein changed, or otherwise changed so that a change of control could occur. This requirement does not apply to any movement of DEBS or PESC within the Duke Energy holding company system that does not constitute a change of control.

(g) DEC and PEC may participate in joint comments and other joint filings with Affiliates only when such participation fully complies with both the letter and the spirit of the Regulatory Conditions. Any filing made by DEBS or PESC on behalf of DEC or PEC, or in which DEC or PEC participates, must clearly identify DEBS or PESC as an agent of DEC or PEC for purposes of making the filing.

(h) Neither DEC, PEC, Duke Energy, another Affiliate, nor a Nonpublic Utility Operation shall make any assertion or argument either on its own initiative or in support of any other entity's assertions in any forum – whether judicial, administrative, federal, state, or otherwise – with respect to any contract, transaction, or other matter in which DEC or PEC is involved or proposes to be involved or any contract, transaction, or matter involving or proposed to involve Duke Energy, any other Affiliate, or any Nonpublic Utility Operation that may have an Effect on DEC's or PEC's Rates or Service, that the Commission is in any way preempted, in whole or in part, by Federal Law, or is acting beyond the Commission's power, authority or jurisdiction, in exercising its authority under North Carolina law as follows:

(i) reviewing the reasonableness of any Affiliate commitment entered into or proposed to be entered into by DEC or PEC, or disallowing the costs of, or imputing revenues related to such commitment to, DEC or PEC;

(ii) exercising its authority over financings or setting rates based on the capital structure, corporate structure, debt costs, or equity costs that it finds to be appropriate for retail ratemaking purposes;

(iii) reviewing the reasonableness of any commitment entered into or proposed to be entered into by DEC or PEC to transfer an asset;

(iv) mandating, approving, or otherwise regulating a transfer of assets;

(v) scrutinizing and establishing the value of any asset transfers for the purpose of determining the rates for services rendered to DEC's or PEC's Retail Native Load Customers; or

(vi) exercising any other lawful authority it may have.

Should any other entity so assert, neither DEC, PEC, Duke Energy, other Affiliates, nor the Nonpublic Utility Operations shall support any such assertion and shall, promptly upon learning of such assertion, advise and consult with the Commission and the Public Staff regarding such assertion.

(vii) DEC, PEC, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall (A) bear the full risk of any preemptive effects of Federal Law with respect to any contract, transaction, or commitment entered into or made or proposed to be entered into or made by DEC or PEC or which may otherwise affect DEC's or PEC's operations, service, or rates and (B) shall take all actions as may be reasonably necessary and appropriate to hold North Carolina ratepayers harmless from rate increases, foregone opportunities for rate decreases or any other adverse effects of such preemption. Such actions include, but are not limited to, filing with and making reasonable efforts to obtain approval from the FERC or other applicable federal entity of such commitments as the Commission deems reasonably necessary to prevent such preemptive effects.

3.11 FERC Filings and Orders. In addition to the filing requirements of Commission Rule R8-27 and all other applicable statutes and rules, DEC and PEC shall, on a quarterly basis, file with the Commission the following: (a) a list of all active dockets at the FERC, including a sufficient description to identify the type of proceeding, in which DEC, PEC, Duke Energy, DEBS, or PESC is a party, with new information in each quarterly filing tracked; and (b) a list of the periodic reports filed by DEC, PEC, Duke Energy, DEBS, or PESC with the FERC, including sufficient information to identify the subject matter of each report and how each report can be accessed. These filings shall be made in Docket Nos. E-7, Sub 986E, and E-2, Sub 998E, as appropriate, and updated regularly. In addition, DEC and PEC shall serve on the Public Staff all filed cost-based and market-based wholesale agreements and amendments; all filings related to their Joint Open Access Transmission Tariff; interconnection agreements and amendments; and any other filings made with the FERC, to the extent these other filings are reasonably likely to have an Effect on DEC's or PEC's Rates or Service.

SECTION IV
JOINT DISPATCH

The following Regulatory Conditions are intended to prevent the jurisdiction and authority of the Commission from being preempted as a result of the JDA, to ensure that DEC's and PEC's Retail Native Load Customers receive adequate benefits from the JDA, and to ensure that both joint dispatch costs and the sharing of cost savings can be appropriately audited.

4.1 Conditional Approval and Notification Requirement. DEC and PEC acknowledge that the Commission's approval of the merger and the transfer of dispatch control from PEC to DEC for purposes of implementing the JDA and any successor document is conditioned upon the JDA or successor document never being interpreted as providing for or requiring: (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 PEC 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 or PEC to the other, or (f) any equalization of DEC's and PEC's production costs or rates. If, at any time, DEC, PEC or any other Affiliate learns that any of the foregoing interpretations are being considered, in whatever forum, they shall promptly notify and consult with the Commission and the Public Staff regarding appropriate action.

4.2 Advance Notice Required. To the extent that DEC and PEC desire to engage in any of items (a) through (f) listed in Regulatory Condition 4.1, above, DEC and PEC shall file advance notice with the Commission at least 30 days prior to taking any action to amend the JDA or a successor document or to enter into a separate agreement. The provisions of Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition.

4.3 Function in DEC or PEC. The joint dispatch function, as provided in the JDA or in a successor document, shall be performed by employees of either DEC or PEC.

4.4 No Limitation on Obligations. DEC and PEC acknowledge that nothing in the JDA or any successor document is intended to alter DEC's and PEC's public utility obligations under North Carolina law or to provide for joint dispatch in a fashion that is inconsistent with those obligations, including, without limitation, the following: (a) DEC's obligation to plan for and provide least cost electric service to its Retail Native Load Customers and PEC's obligation to plan for and provide least cost electric service to its Retail Native Load Customers; (b) DEC's obligation to serve its Retail Native Load Customers with the lowest cost power it can reasonably generate or purchase from other sources, before making power available for Non-Native Load Sales; and (c) PEC's obligation to serve its Retail Native Load Customers with the lowest cost power it can reasonably generate or purchase from other sources, before making power available for Non-Native Load Sales.

4.5 Protection of Retail Native Load Customers. All joint dispatch and other activities pursuant to the proposed JDA or successor document shall be performed in such a manner as to (a) ensure the reliable fulfillment of DEC's and PEC's respective service obligations to their Retail Native Load Customers, (b) fulfill each utility's obligation to serve its own Retail Native Load Customers with its lowest cost generation; and (c) minimize the total costs incurred by DEC and PEC to fulfill their respective obligations to their Retail Native Load Customers. In no event shall any Non-Native Load Sales be made if, based upon information known, anticipated, or reasonably available at the time a sale is made, any such sale results in higher fuel and fuel-related costs or non-fuel O&M costs, on a replacement cost basis, than would otherwise have been incurred unless the revenues credited from each such sale more than offset the higher costs.

4.6 Treatment of Costs and Savings. DEC's and PEC's respective fuel and fuel-related costs and non-fuel O&M costs, and the treatment of savings for retail ratemaking purposes, shall be calculated as provided in the JDA, unless explicitly changed by order of the Commission.

4.7 Required Records. DEC and PEC shall keep records related to the JDA or any successor document as prescribed by the Commission and in such detail as may be necessary to enable the Commission and the Public Staff to audit both the actual joint dispatch costs and the sharing of cost savings.

4.8 Auditing of Negative Margins. DEC and PEC also shall keep records that provide such detail as may be necessary to enable the Commission and the Public Staff to audit the circumstances that cause any negative margin on a Non-Native Load Sale or a negative transfer payment made pursuant to Section 7.5(a)(ii) of the JDA.

4.9 Protection of Commission's Authority. Neither DEC, PEC, nor any Affiliate shall assert in any forum – whether judicial, administrative, federal, state, local or otherwise – either on its own initiative or in support of any other entity's assertions that any aspect of the JDA or successor document is intended to diminish or alter the jurisdiction or authority of the Commission over DEC or PEC, including, among other things, the jurisdiction and authority of the Commission to do the following: (a) establish the retail rates on a bundled basis for DEC or PEC, (b) to impose regulatory accounting and reporting requirements, (c) impose service quality standards, (d) require DEC and PEC to engage separately in least cost integrated resource planning, and (e) issue certificates of public convenience and necessity for new generating and transmission resources.

4.10 Preventive Action Required. DEC, PEC, Duke Energy, and other Affiliates shall take all necessary actions to prevent the generating facilities owned or controlled by DEC or PEC from being considered by the FERC to be (a) part, or all, of a power pool, (b) sufficiently integrated to be one integrated system, or (c) otherwise fully subject to the FERC's jurisdiction, as the result of DEC's and PEC's participation in the JDA or any successor document.

4.11 Modification and Termination. DEC and PEC shall modify or terminate the JDA if at any time following consummation of the Merger the Commission finds, after notice and opportunity to be heard, that the JDA does not produce overall cost savings for, or is otherwise not in the best interests of, the North Carolina ratepayers of both DEC and PEC.

SECTION V
TREATMENT OF AFFILIATE COSTS AND RATEMAKING

The following Regulatory Conditions are intended to ensure that the costs incurred by DEC and PEC are properly incurred, accounted for, and directly charged, directly assigned, or allocated to their respective North Carolina retail operations and that only costs that produce benefits for their respective Retail Native Load Customers are included in DEC's and PEC's North Carolina retail cost of service for ratemaking purposes. The procedures set forth in Condition 13.2 do not apply to an advance notice filed pursuant to this section.

5.1 Access to Books and Records. In accordance with North Carolina law, the Commission and the Public Staff shall continue to have access to the books and records of DEC, PEC, Duke Energy Corporation, other Affiliates, and the Nonpublic Utility Operations.

5.2 Procurement or Provision of Goods and Services by DEC or PEC to or from Affiliates or Nonpublic Utility Operations. Except as to transactions between DEC and PEC pursuant to filed and approved service agreements and lists of services, and subject to additional provisions set forth in the Code of Conduct, DEC and PEC shall take the following actions in connection with procuring goods and services for their respective utility operations from Affiliates or Nonpublic Utility Operations and providing goods and services to Affiliates or Nonpublic Utility Operations:

(a) DEC and PEC shall seek out and buy all goods and services from the lowest cost qualified provider of comparable goods and services, and shall have the burden of proving that any and all goods and services procured from their Utility Affiliates, Non-Utility Affiliates, and Nonpublic Utility Operations have been procured on terms and conditions comparable to the most favorable terms and conditions reasonably available in the relevant market, which shall include a showing that comparable goods or services could not have been procured at a lower price from qualified non-Affiliate sources or that neither DEC nor PEC could have provided the services or goods for itself on the same basis at a lower cost. To this end, no less than every four years DEC and PEC shall perform comprehensive, non-solicitation based assessments at a functional level of the market competitiveness of the costs for goods and services they receive from a Utility Affiliate, DEBS, PESC, another Non-Utility Affiliate, and a Nonpublic Utility Operation, including periodic testing of services being provided internally or obtained individually through outside providers. To the extent the Commission approves the procurement or provision of goods and services between and among DEC, PEC, and the Utility Affiliates, those goods and services may be provided at the supplier's Fully Distributed Cost.

(b) To the extent they are allowed to provide such goods and services, DEC and PEC shall have the burden of proving that all goods and services provided by either of them to Duke Energy, a Non-Utility Affiliate, any other Affiliate, or a Nonpublic Utility Operation have been provided on the terms and conditions comparable to the most favorable terms and conditions reasonably available in the market, which shall include a showing that such goods or services have been provided at the higher of cost or market price. To this end, no less than every four years DEC and PEC shall perform comprehensive, non-solicitation based assessments at a functional level of the market competitiveness of the costs for goods and services provided by either of them to a Utility Affiliate, DEBS, PESC, another Non-Utility Affiliate, any other Affiliate, and a Nonpublic Utility Operation.

(c) The periodic assessments required by subdivisions (a) and (b) of this subsection may take into consideration qualitative as well as quantitative factors. To the extent that comparable goods or services provided to DEC or PEC or by DEC or PEC are not commercially available, this Regulatory Condition shall not apply.

5.3 Location of Core Utility Functions. Core utility functions (i.e., those that are considered public utility operations and support functions) will be part of DEC and PEC, and the employees performing these functions will be DEC and PEC employees and not service company employees of DEBS or PESC. If in the future DEC or PEC desires to move these functions to another entity, Regulatory Condition 13.2 will apply and 30 days' advance notice will be required. The following functions are core utility functions for DEC and PEC:

(a) Outage and Maintenance Services Fuels and System Optimization Power Generation Operations;

(b) Electric Transmission and Distribution Operations, Engineering and Construction; (except for grid modernization functions, which may remain in DEBS);

(c) Project Management and Construction (except for Enterprise Project Management Center of Excellence, Project Development and Initiation, Fossil/Hydro Retrofits, Major Project Service**s**, Commercial and International Major Projects and Performance Improvement, which may remain in DEBS);

(d) Environmental Health and Safety (except for Health and Safety, Environmental Programs and Compliance, EHS Support Systems, **and** Duke Energy International, which may remain in DEBS);

(e) Central Programs and Services for Fossil/Hydro Services (except for Central Programs, Application Support, NERC/CIP, SMEs, Discipline Engineering, CT Services, Lab Services, Environmental Compliance Strategy, and Emerging Technology, which may remain in DEBS);

(f) Customer Operations/Customer Relations;

(g) Rates and Regulatory (except for Rate Design and Analysis and State Support and Research, which may remain in DEBS);

(h) Nuclear Generation (except for Nuclear Development, which may remain in DEBS);

(i) Wholesale Power and Renewable Generation; and

(j) Integrated Resource Planning and Analytics (except for Production Cost Modeling & Data Management, which may remain in DEBS).

Notwithstanding the foregoing, DEC and PEC may file a list of employees at the higher levels of management for their core utility functions that they propose to remain or become DEBS or PESC employees. Within 30 days of this filing, the Public Staff shall file a response and make a recommendation as to how the Commission should proceed. This filing shall be made in Docket No. E-7, Sub 986A, and will not be subject to the provisions of Regulatory Condition 13.2.

5.4 Service Agreements and Lists of Services.

(a) DEC and PEC shall file pursuant to G.S. 62-153 final proposed service agreements that authorize the provision and receipt of non-power goods or services between and among DEC, PEC, their Affiliates or Nonpublic Utility Operations, the list(s) of goods and services that DEC and PEC each intend to take from DEBS and PESC, the list(s) of goods and services DEC and PEC intend to take from each other and the Utility Affiliates, and the basis for the determination of such list(s) and the elections of such services. All such lists that involve payment of fees or other compensation by DEC or PEC 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.

(b) DEC and PEC shall take goods and services from an Affiliate only in accordance with the filed service agreements and approved list(s) of services. DEC and PEC shall file notice with the Commission in Docket Nos. E-7, Sub 986A, and E-2, Sub 998A, respectively, at least 15 days prior to making any proposed changes to the service agreements or to the lists of services.

5.5 Charges for and Allocations of the Costs of Affiliate Transactions. To the maximum extent practicable, all costs of Affiliate transactions shall be directly charged. When not practicable, such costs shall be assigned in proportion to the direct charges. If such costs are of a nature that direct charging and direct assignment are not practicable, they shall be allocated in accordance with Commission-approved allocation methods. The following additional provisions shall apply:

(a) DEC and PEC shall keep on file with the Commission cost allocation manuals (CAMs) with respect to goods or services provided by DEC or PEC, any Utility Affiliate, DEBS or PESC, any other Non-Utility Affiliate, Duke Energy, any other Affiliates, or any Nonpublic Utility Operation to either DEC or PEC.

(b) Each CAM shall describe how all directly charged, direct assignment, and other costs for each provider of goods and services will be charged between and among

DEC, PEC, their Utility Affiliates, Non-Utility Affiliates, Duke Energy, any other Affiliates, and the Nonpublic Utility Operations, and shall include a detailed review of the common costs to be allocated and the allocation factors to be used.

(c) The CAM(s) shall be updated annually, and the revised CAM(s) shall be filed with the Commission no later than March 31 of the year that the CAM(s) are to be in effect. DEC and PEC shall review the appropriateness of the allocation bases every two years, and the results of such review shall be filed with the Commission. Interim changes shall be made to the CAM(s), if and when necessary, and shall be filed with the Commission, in accordance with Regulatory Condition 5.6.

(d) No changes shall be made to the procedures for direct charging, direct assigning, or allocating the costs of Affiliate transactions or to the method of accounting for such transactions associated with goods and services (including Shared Services provided by DEBS or PESC) provided to or by Duke Energy, other Affiliates, and the Nonpublic Utility Operations until DEC or PEC has given 15 days' notice to the Commission of the proposed changes, in accordance with Regulatory Condition 5.6.

5.6 Procedures Regarding Interim Changes to the CAMs or Lists of Goods and Services for which 15 Days' Notice Is Required. With respect to interim changes to the CAMs or changes to lists of goods and services, for which the 15 day notice to the Commission is required, the following procedures shall apply: the Public Staff shall file a response and make a recommendation as to how the Commission should proceed before the end of the notice period. If the Commission has not issued an order within 30 days of the end of the notice period, DEC or PEC may proceed with the changes but shall be subject to any fully adjudicated Commission order on the matter. The provisions of Regulatory Condition 13.2 do not apply to advance notices filed pursuant to Regulatory Condition 5.5(c) and (d). Such advance notices shall be filed in Docket Nos. E-7, Sub 986A, and E-2, Sub 998A.

5.7 Annual Reports of Affiliate Transactions. DEC and PEC shall file annual reports of affiliated transactions with the Commission in a format to be prescribed by the Commission in Docket Nos. E-7, Sub 986A, and E-2, Sub 998A. The report shall be filed on or before May 30 of each year, for activity through December 31 of the preceding year. DEC, PEC, and other parties may propose changes to the required affiliated transaction reporting requirements and submit them to the Commission for approval, also in Docket Nos. E-7, Sub 986B, and E-2, Sub 998B.

5.8 Third-party Independent Audits of Affiliate Transactions.

(a) No less often than every two years, a third-party independent audit shall be conducted related to the affiliate transactions undertaken pursuant to Affiliate agreements filed in accordance with Regulatory Condition 5.4 and of DEC's and PEC's compliance with all conditions approved by the Commission concerning Affiliate transactions, including the propriety of the transfer pricing of goods and services between and/or among DEC, PEC, other Affiliates, and all of the Nonpublic Utility Operations.

(i) The first audit following the close of the transaction shall begin two years from the date of close and shall include whether DEC and PEC have adopted systems, policies, CAMs, and other processes to ensure compliance with all of the conditions related to Affiliate dealings and the Code of Conduct and have operated in accordance with those conditions and Code of Conduct.

(ii) The second audit shall begin two years from the date of the Commission's order on the independent auditor's final report on the first audit or, if no such order is issued, two years from the date of such final report. It shall include whether DEC's and PEC's transactions, services, and other Affiliate dealings pursuant to the regulated utility-to-regulated utility service agreement and any other utility to utility agreements are consistent with all of the conditions related to affiliate dealings and the Code of Conduct and whether DEC and PEC have operated in accordance with those conditions and Code of Conduct.

(iii) The third audit shall begin two years from the date of the Commission's order on the independent auditor's final report on the second audit or, if no such order is issued, two years from the date of such final report. It shall include whether DEC's and PEC's transactions, services, and other Affiliate dealings pursuant to the Service Company Utility Service Agreement and other Affiliate transactions other than transactions undertaken pursuant to regulated utility to regulated utility service agreements are consistent with all of the conditions related to affiliate dealings and the Code of Conduct and whether DEC and PEC have operated in accordance with those conditions and Code of Conduct.

(iv) Thereafter, independent audits shall occur every two years from the date of the Commission's order on the immediately preceding auditor's final report or, if no such order is issued, two years from the date of such final report. The subject matter of these audits shall alternate between the subject matters for the second and third independent audits. DEC or PEC may request a change in the frequency of the audit reports in future years, subject to approval by the Commission.

(b) The following further requirements apply:

(i) The independent auditor shall have sufficient access to the books and records of DEC, PEC, Duke Energy, other Affiliates, and all of the Nonpublic Utility Operations to perform the audits.

(ii) For each audit, the Public Staff shall propose one or more independent auditor(s). DEC, PEC, and other parties shall have an opportunity to comment and propose additional auditors. Selection of the independent auditor shall be made by the Commission. Any party proposing an independent auditor shall file such auditor's audit proposal with the Commission.

(iii) The independent auditor shall be supervised in its duties by the Public Staff, and the auditor's reports shall be filed with the Commission.

5.9 <u>On-Going Review by Commission</u>.

(a) The services rendered by DEC and PEC to their Affiliates and Nonpublic Utility Operations and the services received by DEC or PEC from their Affiliates and Nonpublic Utility Operations pursuant to the filed service agreements, the costs and benefits assigned or allocated in connection with such services, and the determination or calculation of the bases and factors utilized to assign or allocate such costs and benefits, as well as DEC's and PEC's compliance with the Commission-approved Code of Conduct and all Regulatory Conditions, shall remain subject to ongoing review. These agreements shall be subject to any Commission action required or authorized by North Carolina law and the Rules and orders of the Commission.

(b) The service agreements, the CAM(s) and the assignments and allocations of costs pursuant thereto, the biannual allocation factor reviews required by Regulatory Condition 5.4(c), the list(s) and the goods and services provided pursuant thereto, and any changes to these documents shall be subject to ongoing Commission review, and Commission action if appropriate.

5.10 <u>Future Orders</u>. For the purposes of North Carolina retail accounting, reporting, and ratemaking, the Commission may, after appropriate notice and opportunity to be heard, issue future orders relating to DEC's or PEC's cost of service as the Commission may determine are necessary to ensure that DEC's and PEC's operations and transactions with their Affiliates and Nonpublic Utility Operations are consistent with the Regulatory Conditions and Code of Conduct, and with any other applicable decisions of the Commission.

5.11 <u>Review by the FERC</u>. Notwithstanding any of the provisions contained in these Regulatory Conditions, to the extent the allocations adopted by the Commission when compared to the allocations adopted by the other State commissions with ratemaking authority as to a Utility Affiliate of DEC or PEC result in significant trapped costs related to "non-power goods or administrative or management services provided by an associate company organized specifically for the purpose of providing such goods or services to any public utility in the same holding company system," including DEC and PEC, DEC and PEC may request pursuant to Section 1275(b) of Subtitle F in Title XII of PUHCA 2005 that the FERC "review and authorize the allocation of the costs for such goods and services to the extent relevant to that associate company." Such review and authorization shall have whatever effect it is determined to have under the law. The quoted language in this Condition is taken directly from Section 1275(b) of Subtitle F in Title XII of PUHCA 2005. The terms "associate company" and "holding company system" are defined in Sections 1262(2) and 1262(9), respectively, of Subtitle F in Title XII of PUHCA 2005 and have the same meanings for purposes of this condition.

5.12 Biannual Review of Certain Transactions by Internal Auditors. Transactions between DEC or PEC and Duke Energy, other Affiliates, or the Nonpublic Utility Operations, transactions between DEC and PEC, and other transactions between or among Affiliates if such transactions are reasonably likely to have a significant Effect on DEC's or PEC’s Rates or Service, shall be reviewed at least biannually by Duke Energy Corporation's internal auditors. To the extent external audits of the transactions are conducted, DEC and PEC shall make available such audits for review by the Public Staff and the Commission. DEC and PEC also shall make available for review by the Public Staff and the Commission all workpapers relating to internal audits and all other internal audit workpapers, if any, related to affiliate transactions, and shall not oppose Public Staff and Commission requests to review relevant external audit workpapers.

5.13 Notice of Service Company and Non-Utility Affiliates FERC Audits. At such time as either DEC, PEC, Duke Energy, DEBS, or PESC receives notice from the FERC related to an audit of any Affiliate of DEC or PEC, DEC or PEC shall promptly file a notice the Commission that such an audit will be commencing. Any initial report of the FERC’s audit team shall be provided to the Public Staff, and any final report shall be filed with the Commission in Docket Nos. E-7, Sub 986E, and E-2, Sub 998E, respectively.

5.14 Acquisition Adjustment. Any acquisition adjustment that results from the Merger shall be excluded from DEC’s and PEC’s utility accounts and treated for regulatory accounting, reporting, and ratemaking purposes so that it does not affect DEC’s or PEC’s North Carolina retail electric rates and charges.

5.15 Non-Consummation of Merger. If the merger is not consummated, neither the cost, nor the receipt, of any termination payment between Duke Energy and Progress Energy shall be allocated to DEC or PEC or recorded on their books. DEC’s or PEC’s North Carolina retail customers shall not otherwise bear any direct expenses or costs associated with a failed merger.

5.16 Protection from Commitments to Wholesale Customers.

(a) For North Carolina retail electric cost of service/ratemaking purposes, DEC’s and PEC’s respective electric system costs shall be assigned or allocated between and among retail and wholesale jurisdictions based on reasonable and appropriate cost causation principles. For cost of service/ratemaking purposes, North Carolina retail ratepayers shall be held harmless from any cost assignment or allocation of costs resulting from agreements between DEC and the Catawba Joint Owners, between PEC and the North Carolina Eastern Municipal Power Agency as joint owner, and between either DEC or PEC and any of their wholesale customers.

(b) To the extent commitments to DEC's or PEC's wholesale customers relating to the Merger are made by or imposed upon DEC or PEC, the effects of which (i) decrease the bulk power revenues that are assigned or allocated to DEC's or PEC's North Carolina retail operations or credited to DEC's or PEC's jurisdictional fuel expenses, (ii) increase DEC's or PEC's North Carolina retail cost of service, or (iii) increase DEC's or PEC's North Carolina retail fuel costs under reasonable cost assignment and allocation practices approved or allowed by the Commission, those effects shall not be recognized for North Carolina retail cost of service or ratemaking purposes.

(c) To the extent that commitments are made by or imposed upon DEC, PEC, Duke Energy Corporation, another Affiliate, or a Nonpublic Utility Operation relating to the Merger, either through an offer, a settlement, or as a result of a regulatory order, the effects of which serve to increase the North Carolina retail cost of service or North Carolina retail fuel costs under reasonable cost allocation practices, the effects of these commitments shall not be recognized for North Carolina retail ratemaking purposes.

5.17 Joint Owner-Specific Issues. Assignment or allocation of costs to the North Carolina retail jurisdiction shall not be adversely affected by the manner and amount of recovery of electric system costs from (a) the Catawba Joint Owners as a result of agreements between DEC and the Catawba Joint Owners or (b) the North Carolina Eastern Municipal Power Agency as a result of agreements between it and PEC.

5.18 Inclusion of Cost Savings in Future Rate Proceedings. Neither DEC, PEC, Duke Energy Corporation, any other Affiliate, nor a Nonpublic Utility Operation shall assert that any interested party is prohibited from seeking the inclusion in future rate proceedings of cost savings that may be realized as a result of any business combination transaction impacting DEC and PEC.

5.19 Reporting of Costs to Achieve. The North Carolina portion of costs to achieve any business combination transaction savings shall be reflected in DEC's and PEC's North Carolina ES-1 report as recorded on its books and records under generally accepted accounting principles. DEC and PEC shall include as a footnote in the ES-1 reports the merger related costs to achieve that were expensed during the relevant period.

5.20 Accounting for Costs to Achieve Related to Historical Events Involving PEC. All costs of PEC's merger with North Carolina Natural Gas Company, the Formation of Progress Energy, and Progress Energy's merger with Florida Progress Corporation shall be excluded from PEC's utility accounts, and all direct or indirect corporate cost increases, if any, attributable to those three events shall be excluded from utility costs for all purposes that affect PEC's regulated retail rates and charges. For purposes of this condition, the term "corporate cost increases" is defined as costs in excess of the level PEC would have (a) incurred using prudent business judgment, or (b) had allocated to it, had these transactions not occurred. "Corporate cost increases" shall also include any payments made under change-of-control agreements, salary continuation agreements, and/or other severance- or personnel-type arrangements that are reasonably attributable to these transactions.

5.21 Liabilities of Cinergy Corp. and Florida Progress Corporation.

(a) DEC's and PEC's Retail Native Load Customers shall be held harmless from all liabilities of Cinergy Corp. and its subsidiaries, including those incurred prior to and after Duke Energy's acquisition of Cinergy Corp. in 2006. These liabilities include, but are not limited to, those associated with the following: (i) manufactured gas plant sites, (ii) asbestos claims, (iii) environmental compliance, (iv) pensions and other employee benefits, (v) decommissioning costs; and (vi) taxes.

(b) DEC's and PEC's Retail Native Load Customers shall be held harmless from all liabilities of Florida Progress Corporation and its subsidiaries, including those incurred prior to and after Progress Energy's acquisition of Florida Progress Corporation in 2000. These liabilities include, but are not limited to, those associated with the following: (i) any outages at and repairs of Crystal River 3, (ii) manufactured gas plant sites, (iii) asbestos claims, (iv) environmental compliance, (v) pensions and other employee benefits, (vi) decommissioning costs, and (vii) taxes.

(c) DEC's Retail Native Load Customers shall be held harmless from all current and prospective liabilities of PEC, and PEC's Retail Native Load Customers shall be held harmless from all current and prospective liabilities of DEC.

5.22 Hold Harmless Commitment. DEC, PEC, Duke Energy, the other Affiliates, and all of the Nonpublic Utility Operations shall take all such actions as may be reasonably necessary and appropriate to hold North Carolina retail ratepayers harmless from the effects of the Merger, including rate increases or foregone opportunities for rate decreases, and other effects otherwise adversely impacting North Carolina retail customers.

5.23 Cost of Service Manuals. Within six months after the closing date of the Merger, DEC and PEC shall each file with the Commission revisions to its electric cost of service manual to reflect any changes to the cost of service determination process made necessary by the Merger, any subsequent alterations in the organizational structure of DEC, PEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations, or other circumstances that necessitate such changes. These filings shall be made in Docket Nos. E-7, Sub 986A, and E-2, Sub 998A, respectively.

SECTION VI
CODE OF CONDUCT

These Regulatory Conditions include a Code of Conduct in Appendix A. The Code of Conduct governs the relationships, activities and transactions between and among the public utility operations of DEC, PEC, Duke Energy, the Affiliates of DEC and PEC, and the Nonpublic Utility Operations of DEC and PEC.

6.1 Obligation to Comply with Code of Conduct. DEC, PEC, Duke Energy, the other Affiliates, and the Nonpublic Utility Operations shall be bound by the terms of the Code of Conduct set forth in Appendix A and as it may subsequently be amended.

SECTION VII
FINANCINGS

The following Regulatory Conditions are intended to ensure (a) that DEC's and PEC's capital structures and cost of capital are not adversely affected through their affiliation with Duke Energy, each other, and other Affiliates and (b) that both DEC and PEC have sufficient access to equity and debt capital at a reasonable cost to adequately fund and maintain their current and future capital needs and otherwise meet their service obligations to their Customers.

These conditions do not supersede any orders or directives of the Commission regarding specific securities issuances by DEC, PEC, or Duke Energy. The approval of the Merger by the Commission does not restrict the Commission's right to review, and by order to adjust, DEC's or PEC's cost of capital for ratemaking purposes for the effect(s) of the securities-related transactions associated with the Merger.

7.1 Accounting for Equity Investment in Holding Company Subsidiaries. Duke Energy shall maintain its books and records so that any net equity investment in Cinergy Corp. and Progress Energy, their subsidiaries, or their successors, by Duke Energy or any Affiliates can be identified and made available on an ongoing basis. This information shall be provided to the Public Staff upon its request.

7.2 Accounting for capital structure components and cost rates. Duke Energy , DEC, and PEC shall keep their respective accounting books and records in a manner that will allow all capital structure components and cost rates of the cost of capital to be identified easily and clearly for each entity on a separate basis. This information shall be provided to the Public Staff upon its request.

7.3 Accounting for Equity Investment in DEC and PEC. DEC and PEC shall keep their respective accounting books and records so that the amount of Duke Energy's equity investment in DEC and PEC can be identified and made available upon request on an ongoing basis. This information shall be provided to the Public Staff upon request.

7.4 Reporting of Capital Contributions. As part of their Commission ES-1 Reports, DEC and PEC shall include a schedule of any capital contribution(s) received from Duke Energy in the applicable calendar quarter.

7.5 Identification of Long-term Debt Issued by DEC or PEC. DEC and PEC shall each identify as clearly as possible long-term debt (of more than one year's duration) that they issue in connection with their regulated utility operations and capital requirements or to replace existing debt.

7.6 Procedures Regarding Proposed Financings.

(a) For all types of financings for which DEC or PEC (or their subsidiaries) are the issuers of the respective securities, DEC or PEC (or their subsidiaries) shall request approval from the Commission to the extent required by G.S. 62-160 through G.S. 62-169 and Commission Rule R1-16. Generally, the format of these filings should be consistent with past practices. A "shelf registration" approach (similar to Docket No. E-7, Sub 727) may be requested.

(b) For all types of financings by Duke Energy, other than short-term debt as described in G.S. 62-167, the following shall apply:

(i) On or before January 15 of each year, Duke Energy shall file with the Commission and serve on the Public Staff an advance confidential plan of all securities issuances that it anticipates to occur during that calendar year. The annual confidential plan shall include a description of all financings that Duke Energy reasonably believes may occur during the applicable calendar year. A description for each financing shall include the best estimates of the following: type of security; estimate of cost rate (e.g., interest rate for debt); amount of proceeds; brief description of the purpose/reason for issue; and amount of proceeds, if any, that may flow to DEC or PEC.

(ii) If at any time material changes to the financing plans included in the filed plan appear likely, Duke Energy shall file a revised 30-day advance confidential plan that specifically addresses such changes with the Commission and serve such notice on the Public Staff.

(iii) At the time of the confidential plan filings identified above, Duke Energy shall also file a non-confidential notice that states that a confidential plan has been filed in compliance with this Regulatory Condition 7.6(b).

(iv) Duke Energy may proceed with equity issuances upon the filing of the confidential plan. However, actual debt issuances shall not occur until 30 days after the advance confidential plan or revised plans are filed. In the event it is not feasible for Duke Energy to file a revised advance confidential plan for a material change 30 days in advance, such plan shall be filed by a date that allows adequate time for review or a debt issuance shall be delayed to allow such review. Prior to the Commission's action on the confidential plan for the year in which the plan is filed, Duke Energy may issue securities authorized under the previous year's plan to the extent such securities were not issued during the previous year.

(v) Within 15 days after the filing of an advance confidential plan or revised plan, the Public Staff shall file a confidential report with the Commission with respect to whether any debt issuances require approval pursuant to

G.S. 62-160 through G.S. 62-169 and Commission Rule R1-16 and shall recommend that the Commission issue an order deciding how to proceed. Duke Energy shall have seven days in which to respond to the report. If the Commission determines that any debt issuance requires approval, the Commission shall issue an order requiring the filing of an application and no such issuance shall occur until the Commission approves the application. If the Commission determines that no debt issuance requires approval, the Commission shall issue an order so ruling. At the end of the notice period, Duke Energy may proceed with the debt issuance, but shall be subject to any fully adjudicated Commission order on the matter; provided, however, that nothing herein shall affect the applicability of G.S. 62-170 or other similar provision to such securities or obligations.

(vi) On or before April 15 of each year, Duke Energy shall file with the Commission a report on all financings that were executed for the previous calendar year. The actual reports should include the same information as required above for the advance plans plus the actual issuance costs.

(c) If a filing with the Securities and Exchange Commission or other federal agency will be made in connection with a securities issuance, the notice shall describe such filing(s) and indicate the approximate date on which it would occur.

(d) Securities issuances or financings that are associated with a merger, acquisition, or other business combination shall be filed in conjunction with the information requirements and deadlines stated in Regulatory Conditions 9.1 and 9.2, and this Condition 7.6 shall not apply to such securities issuances or financings.

7.7 Money Pool Agreement. Subject to the limitations imposed in Regulatory Condition 8.4, DEC and PEC may borrow through Duke Energy's "Utility Money Pool Agreement" (Utility MPA), provided as follows: (a) participation in the Utility MPA is limited to the parties to the Utility MPA dated November 1, 2008, as filed with the Commission on November 17, 2008, in Docket No. E-7, Subs 795A and 810, plus PEC, PEF, Progress Energy, and PESC; and (b) the Utility MPA continues to provide that no loans through the Utility MPA will be made to, and no borrowings through the Utility MPA will be made by, Duke Energy, Progress Energy, and Cinergy Corp. If after December 31, 2011, Duke Ohio's generation assets are no longer dedicated to serving retail load in its service territory and subject to the Electric Security Plan (as approved in Case No. 08-920-EL-SSO, *et al.*), and Duke Ohio continues to be a participant in the Utility MPA, then DEC and PEC shall seek Commission approval within six months of such occurrence, in order to continue participating in the Utility MPA. DEC and PEC shall discontinue such participation within six months after the issuance of a Commission order denying such approval.

7.8 Borrowing Arrangements. Subject to the limitations imposed in Regulatory Condition 8.4, DEC and PEC may borrow short-term funds through one or more joint external debt or credit arrangements (a Credit Facility), provided that the following conditions are met:

(a) No borrowing by DEC or PEC under a Credit Facility shall exceed one year in duration, absent Commission approval;

(b) No Credit Facility shall include, as a borrower, any party other than Duke Energy, DEC, PEC, Duke Indiana, Duke Kentucky, PEF, and, subject to the limitations described in this section, Duke Ohio;

(c) DEC's and PEC's participation in any Credit Facility shall in no way cause either of them to guarantee, assume liability for, or provide collateral for any debt or credit other than its own; and

(d) Duke Ohio may participate in a Credit Facility to the extent the above conditions are met and its generation assets remain dedicated to serving retail load in its service territory and subject to the Electric Security Plan (as approved in Case No. 08-920-EL-SSO, *et al.*), or subject to traditional utility regulation.

If after December 31, 2011, Duke Ohio's generation assets are no longer dedicated to serving retail load in its service territory and subject to the Electric Security Plan (as approved in Case No. 08-920-EL-SSO, *et al.*), then DEC and PEC shall be required to seek Commission approval within six months of such occurrence, in order to continue to participate in a Credit Facility in which Duke Ohio is or will be a participant. DEC and PEC shall discontinue such participation within six months after the issuance of an order by the Commission denying such approval.

7.9 Long-Term Debt Fund Restrictions. DEC and PEC shall acquire their respective long-term debt funds through the financial markets, and shall neither borrow from, nor lend to, on a long-term basis, Duke Energy or any of the other Affiliates. To the extent that either DEC or PEC borrows on short-term or long-term bases in the financial markets and is able to obtain a debt rating, its debt shall be rated under its own name.

SECTION VIII
CORPORATE GOVERNANCE/RING FENCING

The following Regulatory Conditions are intended to ensure the continued viability of DEC and PEC and to insulate and protect DEC, PEC, and their Retail Native Load Customers from the business and financial risks of Duke Energy and the Affiliates within the Duke Energy holding company system, including the protection of utility assets from liabilities of Affiliates.

8.1 Investment Grade Debt Rating. DEC and PEC shall manage their respective businesses so as to maintain an investment grade debt rating on all of their rated debt issuances with all of the debt rating agencies on all of their rated debt issuances. If DEC's or PEC's debt rating falls to the lowest level still considered investment grade at the time, DEC or PEC shall file written notice to the Commission and the Public Staff within five (5) days of such change and an explanation as to why the downgrade occurred. Within 45 days of such notice, DEC or PEC shall provide the Commission and the Public Staff with a specific plan for maintaining and improving its debt rating. The Commission, after notice and hearing, may then take whatever action it deems necessary consistent with North Carolina law to protect the interests of DEC's or PEC's Retail Native Load Customers in the continuation of adequate and reliable service at just and reasonable rates.

8.2 Distributions from DEC and PEC to Holding Company. DEC and PEC shall limit cumulative distributions paid to Duke Energy subsequent to the Merger to (a) the amount of Retained Earnings on the day prior to the closure of the Merger, plus (b) any future earnings recorded by DEC and PEC subsequent to the Merger.

8.3 Debt Ratio Restrictions. To the extent any of Duke Energy's external debt or credit arrangements contain covenants restricting the ratio of debt to total capitalization on a consolidated basis to a maximum percentage of debt, Duke Energy shall ensure that the capital structures of both DEC and PEC individually meet those restrictions.

8.4 Limitation on Continued Participation in Utility Money Pool Agreement and other Joint Debt and Credit Arrangements with Affiliates. DEC and PEC may continue to participate in the Utility MPA and any other authorized joint debt or credit arrangement as provided in Regulatory Conditions 7.7 and 7.8 only to the extent such participation is beneficial to their respective Retail Native Load Customers and does not negatively affect DEC's or PEC's ability to continue to provide adequate and reliable service at just and reasonable rates.

8.5 Notice of Level of Non-Utility Investment by Holding Company System. In order to enable the Commission to determine whether the cumulative investment by Duke Energy in assets, ventures, or entities other than regulated utilities is reasonably likely to have an Effect on DEC's or PEC's Rates or Service so as to warrant Commission action (pursuant to Regulatory Condition 8.7 or other applicable authority) to protect Retail Native Load Customers, Duke Energy shall notify the Commission within 90 days following the end of any fiscal year for which Duke Energy reports to the Securities and Exchange Commission assets in its operations other than regulated utilities that are in excess of 22% of its consolidated total assets. The following procedures shall apply to such a notice:

(a) Any interested party may file comments within 45 days of the filing of Duke Energy's notice.

(b) If timely comments are filed, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than 15 days after the comments are filed, and shall make a recommendation as to how the Commission should proceed. If the Commission determines that the percentage of total assets invested in Duke Energy's its operations other than regulated utilities is reasonably likely to have an Effect on DEC's or PEC's Rates or Service so as to warrant action by the Commission to protect DEC's and PEC's Retail Native Load Customers, the Commission shall issue an order setting the matter for further consideration. If the Commission determines that the percentage threshold being exceeded does not warrant action by the Commission, the Commission shall issue an order so ruling.

8.6 Notice by Holding Company of Certain Investments. Duke Energy shall file a notice with the Commission subsequent to Board approval and as soon as practicable following any public announcement of any investment in a regulated utility or a non-regulated business that represents five (5) percent or more of Duke Energy's book capitalization.

8.7 Ongoing Review of Effect of Holding Company Structure. The operation of DEC and PEC under a holding company structure shall continue to be subject to Commission review. To the extent the Commission has authority under North Carolina law, it may order modifications to the structure or operations of Duke Energy, DEBS, PESC, another Affiliate, or a Nonpublic Utility Operation, and may take whatever action it deems necessary in the interest of Retail Native Load Customers to protect the economic viability of DEC and PEC, including the protection of DEC’s and PEC’s public utility assets from liabilities of Affiliates.

8.8 Investment by DEC or PEC in Non-regulated Utility Assets and Non-utility Business Ventures. Neither DEC nor PEC shall invest in a non-regulated utility asset or any non-utility business venture exceeding $50 million in purchase price or gross book value to DEC or PEC unless it provides 30 days' advance notice. Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition. Purchases of assets, including land, that will be held with a definite plan for future use in providing Electric Services in DEC's or PEC’s franchise area shall be excluded from this advance notice requirement.

8.9 Investment by Holding Company in Exempt Wholesale Generators. By April 15 of each year, Duke Energy shall provide to the Commission and the Public Staff a report summarizing Duke Energy's investment in exempt wholesale generators (EWGs) and foreign utility companies (FUCOs) in relation to its level of consolidated retained earnings and consolidated total capitalization at the end of the preceding year. Exempt wholesale generator and foreign utility company are defined in Section 1262(6) of Subtitle F in Title XII of PUHCA 2005 and have the same meanings for purposes of this condition.

8.10 Notice by DEC or PEC of Default or Bankruptcy of Affiliate. If an Affiliate of DEC or PEC experiences a default on an obligation that is material to Duke Energy or files for bankruptcy, and such bankruptcy is material to Duke Energy, DEC or PEC shall notify the Commission in advance, if possible, or as soon as possible, but not later than ten days from such event.

8.11 Annual Report on Corporate Governance. No later than March 31 of each year, DEC and PEC shall file a report including the following:

(a) A complete, detailed organizational chart (i) identifying DEC, PEC and each Duke Energy financial reporting segment, and (ii) stating the business purpose of each Duke Energy financial reporting segment. Changes from the report for the immediately preceding year shall be summarized at the beginning of the report.

(b) A list of all Duke Energy financial reporting segment that are considered to constitute non-regulated investments and a statement of each segment’s total capitalization and the percentage it represents of Duke Energy's non-regulated investments and total investments. Changes from the report for the immediately preceding year shall be summarized at the beginning of the report.

(c) An assessment of the risks that each unregulated Duke Energy financial reporting segment could pose to DEC or PEC based upon current business activities of those affiliates and any contemplated significant changes to those activities

(d) A description of DEC's, PEC's and each Significant Affiliates actual capital structure. In addition, describe Duke Energy's, DEC's and PEC's goals for DEC's and PEC's capital structure and plans for achieving such goals.

(e) A list of all protective measures (other than those provided for by the Regulatory Conditions adopted in Docket Nos. E-7, Sub 986, and E-2, Sub 998) in effect between DEC, PEC, and any of their Affiliates, and a description of the goal of each measure and how it achieves that goal, such as mitigation of DEC's and PEC's exposure in the event of a bankruptcy proceeding involving any Affiliate(s).

(f) A list of corporate executive officers and other key personnel that are shared between DEC, PEC and any Affiliate, along with a description of each person's position(s) with, and duties and responsibilities to each entity.

(g) A calculation of Duke Energy's total book and market capitalization as of December 31 of the preceding year for common equity, preferred stock, and debt.

SECTION IX
FUTURE MERGERS AND ACQUISITIONS

The following Regulatory Conditions are intended to ensure that the Commission receives sufficient notice to exercise its lawful authority over proposed mergers, acquisitions, and other business combinations involving Duke Energy, DEC, PEC, other Affiliates, or the Nonpublic Utility Operations. The advance notice provisions set forth in Regulatory Condition 13.2 do not apply to these conditions.

9.1 Mergers and Acquisitions by or Affecting DEC or PEC. For any proposed merger, acquisition, or other business combination by DEC or PEC or that would have an Effect on DEC's or PEC's Rates or Service, DEC or PEC shall file in a new Sub docket an application for approval pursuant to G S. 62-111(a) at least 180 days before the proposed closing date for such merger, acquisition, or other business combination.

9.2 Mergers and Acquisitions Believed Not to Have an Effect on DEC's or PEC's Rates or Service. For any proposed merger, acquisition, or other business combination that is believed not to have an Effect on DEC's or PEC's Rates or Service, but which involves Duke Energy, other Affiliates, or the Nonpublic Utility Operations and which has a transaction value exceeding $1.5 billion, the following shall apply:

(a) Advance notification shall be filed with the Commission in a new Sub docket by the merging entities at least 90 days prior to the proposed closing date for such proposed merger, acquisition or other business combination. The advance notification is intended to provide the Commission an opportunity to determine whether the proposed merger, acquisition, or other business combination is reasonably likely to affect DEC or PEC so as to require approval pursuant to G S. 62-111(a). The notification shall contain sufficient information to enable the Commission to make such a determination. If the Commission determines that such approval is required, the 180-day advance filing requirement in subsection (a), above, shall not apply.

(b) Any interested party may file comments within 45 days of the filing of the advance notification.

(c) If timely comments are filed, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than 15 days after the comments are filed, and shall recommend that the Commission issue an order deciding how to proceed. If the Commission determines that the merger, acquisition, or other business combination requires approval pursuant to G.S. 62-111(a), the Commission shall issue an order requiring the filing of an application, and no closing can occur until and unless the Commission approves the proposed merger, acquisition, or business combination. If the Commission determines that the merger, acquisition, or other business combination does not require approval pursuant to G.S. 62-111(a), the Commission shall issue an order so ruling. At the end of the notice period, if no order has been issued, Duke Energy, any other Affiliate, or the Nonpublic Utility Operation may proceed with the merger, acquisition, or other business combination but shall be subject to any fully-adjudicated Commission order on the matter.

SECTION X
STRUCTURE/ORGANIZATION

The following Regulatory Conditions are intended to ensure that the Commission receives adequate notice of, and opportunity to review and take such lawful action as is necessary and appropriate with respect to, changes to the structure and organization of Duke Energy, DEC, PEC, and other Affiliates, and Nonpublic Utility operations as they may affect North Carolina retail ratepayers.

10.1 <u>Transfer of Services, Functions, Departments, Employees, Rights, Assets, or Liabilities</u>. DEC and PEC shall file notice with the Commission 30 days prior to the initial transfer or any subsequent transfer of any services, functions, departments, employees, rights, obligations, assets, or liabilities from DEC or PEC to DEBS, PESC, Duke Energy, another Affiliate, or a Nonpublic Utility Operation that (a) involves services, functions, departments, employees, rights, obligations, assets, or liabilities other than those of a governance or corporate type nature that traditionally have been provided by a service company or (b) potentially would have a significant effect on DEC's or PEC's public utility operations. The provisions of Regulatory Condition 13.2 apply to an advance notice filed pursuant to this Regulatory Condition.

10.2 Notice and Consultation with Public Staff Regarding Proposed Structural and Organizational Changes. Upon request, DEC and PEC shall meet and consult with, and provide requested relevant data to, the Public Staff, regarding plans for significant changes in DEC's, PEC's or Duke Energy's organization, structure (including RTO developments), and activities; the expected or potential impact of such changes on DEC's or PEC's retail rates, operations and service; and proposals for assuring that such plans do not adversely affect DEC's or PEC's Retail Native Load Customers. To the extent that proposed significant changes are planned for the organization, structure, or activities of an Affiliate or Nonpublic Utility Operation and such proposed changes are likely to have an adverse impact on DEC's or PEC's Customers, then DEC's and PEC's plans and proposals for assuring that those plans do not adversely affect their Customers must be included in these meetings. DEC and PEC shall inform the Public Staff promptly of any such events and changes.

SECTION XI
SERVICE QUALITY

The following Regulatory Conditions are intended to ensure that DEC and PEC continue to implement and further their commitment to providing superior public utility service by meeting recognized service quality indices and implementing the best practices of each other and their Utility Affiliates, to the extent reasonably practicable.

11.1 Overall Service Quality. Upon consummation of the Merger, DEC and PEC each shall continue their commitment to providing superior public utility service and shall maintain the overall reliability of electric service at levels no less than the overall levels it has achieved in the past decade.

11.2 Best Practices. DEC and PEC shall make every reasonable effort to incorporate each other's best practices into its own practices to the extent practicable.

11.3 Quarterly Reliability Reports. DEC and PEC shall each provide quarterly service reliability reports to the Public Staff on the following measures: System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). The Public Staff may make such quarterly service reliability reports available to the public upon request.

11.4 Notice of NERC Audit. At such time as either DEC or PEC receive notice that the North American Electric Reliability Corporation and/or the SERC Reliability Corporation will be conducting a non-routine compliance audit with respect to DEC or PEC's compliance with mandatory reliability standards, DEC or PEC shall notify the Public Staff.

11.5 Right-of-Way Maintenance Expenditures. DEC and PEC shall budget and expend sufficient funds to trim and maintain their lower voltage line rights-of-way and their distribution rights-of-way in a manner consistent with their internal right-of-way clearance practices and Commission Rule R8-26. In addition, DEC and PEC shall track annually, on a major category basis, departmental or division budget requests, approved budgets and actual expenditures for right-of-way maintenance.

11.6 Right-of-Way Clearance Practices. DEC and PEC shall each provide a copy of their internal right-of-way clearance practices to the Public Staff, and shall promptly notify the Public Staff of any significant changes or modifications to the practices or maintenance schedules.

11.7 Meetings with Public Staff.

(a) DEC and PEC shall each meet annually with the Public Staff to discuss service quality initiatives and results, including (i) ways to monitor and improve service quality, (ii) right-of-way maintenance practices, budgets, and actual expenditures, and (iii) plans that could have an effect on customer service, such as changes to call center operations.

(b) DEC and PEC shall each meet with the Public Staff at least annually to discuss potential new tariffs, programs, and services that enable its customers to appropriately manage their energy bills based on the varied needs of their customers.

11.8 Customer Access to Service Representatives and Other Services. DEC and PEC shall continue to have knowledgeable and experienced customer service representatives available 24 hours a day to respond to power outage calls and during normal business hours to handle all types of customer inquiries. DEC and PEC shall also maintain up-to-date and user-friendly online services and automated telephone service 24 hours a day to perform routine customer interactions and to provide general billing and customer information.

11.9 Call Center Operations. DEC and PEC shall each provide quarterly reports to the Public Staff regarding measurements of call center performance, including answer times, and customer satisfaction with call center operations.

11.10 Customer Surveys. DEC and PEC shall continue to survey their customers regarding their satisfaction with public utility service and shall incorporate this information into their processes, programs, and services.

SECTION XII
TAX MATTERS

The following Regulatory Conditions are intended to ensure that DEC's and PEC's North Carolina retail ratepayers do not bear any additional tax costs as a result of the merger and receive an appropriate share of any tax benefits associated with the service company Affiliates.

12.1 Costs under Tax Sharing Agreements. Under any tax sharing agreement, neither DEC nor PEC shall seek to recover from its North Carolina retail ratepayers any tax costs that exceed DEC's or PEC's tax liability calculated as if it were a stand-alone, taxable entity for tax purposes.

12.2 Tax Benefits Associated with Service Companies. The appropriate portion of any income tax benefits associated with DEBS and PESC shall accrue to the North Carolina retail operations of DEC and PEC, respectively, for regulatory accounting, reporting, and ratemaking purposes.

SECTION XIII
PROCEDURES

The following Regulatory Conditions are intended to apply to all filings made pursuant to these Regulatory Conditions unless otherwise expressly provided by, Commission order, rule, or statute.

13.1 Filings that Do Not Involve Advance Notice. Regulatory Condition filings that are not subject to Condition 13.2 shall be made in sub dockets of Docket Nos. E-7, Sub 986, and E-2, Sub 998, as follows:

(a) Filings related to affiliate matters required by Regulatory Conditions 5.4, 5.5, 5.6, 5.7, and 5.23 and the filing permitted by Regulatory Condition 5.3 shall be made by DEC and PEC in Sub 986A and Sub 998A, respectively;

(b) Filings related to financings required by Regulatory Condition 7.6, and the filings required by Regulatory Conditions 8.5, 8.6, 8.9, 8.10 and 8.11 shall be made by DEC and PEC in Sub 986B and Sub 998B, respectively;

(c) Files related to compliance as required by Regulatory Conditions 3.1(d) and 14.4 and filings required by Sections III.A.2(l), III.A.3(e), (f), and (g), III.D.5, and III.D.8 of the Code of Conduct shall be made by DEC and PEC in Sub 986C and Sub 998C;

(d) Filings related to the independent audits required by Regulatory Condition 5.8 shall be made in Sub 986D;

(e) Filings related to orders and filings with the FERC, as required by Regulatory Condition 3.1(d), 3.11 and 5.13 shall be made by DEC and PEC in Sub 986E and Sub 998E, respectively;

13.2 Advance Notice Filings. Advance notices filed pursuant to Regulatory Conditions 3.1(c), 3.3(b), 3.7(c), 3.10(c), 4.2, 5.3, 8.8, and 10.1 shall be assigned a new, separate Sub docket. Such a filing shall state what condition and notice period are involved and whether other regulatory approvals are required and shall be in the format of a pleading, with a caption, a title, allegations of the activities to be undertaken, and a verification. Advance notices may be filed under seal if necessary. The following additional procedures apply:

(a) Advance notices of activities to be undertaken shall not be filed until sufficient details have been decided upon to allow for meaningful discovery as to the proposed activities.

(b) The Chief Clerk shall distribute a copy of advance notice filings to each Commissioner and to appropriate members of the Commission Staff and Public Staff.

(c) DEC or PEC shall serve such advance notices on each party to Docket Nos. E-7, Sub 986, and E-2, Sub 998, that has filed a request to receive them with the Commission within 30 days of the issuance of an order approving the Merger in this docket. These parties may participate in the advance notice proceedings without petitioning to intervene. Other interested persons shall be required to follow the Commission's usual intervention procedures.

(d) To effectuate this Regulatory Condition, DEC or PEC shall serve pertinent information on all parties at the time it serves the advance notice. During the advance notice period, a free exchange of information is encouraged, and parties may request additional relevant information. If DEC or PEC objects to a discovery request, DEC or PEC and the requesting party shall try to resolve the matter. If the parties are unable to resolve the matter, DEC or PEC may file a motion for a protective order with the Commission.

(e) The Public Staff shall investigate and file a response with the Commission no later than 15 days before the notice period expires. Any other interested party may also file a response within the notice period. DEC or PEC may file a reply to the response(s).

(f) The basis for any objection to the activities to be undertaken shall be stated with specificity. The objection shall allege grounds for a hearing, if such is desired.

(g) If neither the Public Staff nor any other party files an objection to the activities, no Commission order shall be issued, and the Sub docket in which the advance notice was filed may be closed.

(h) If the Public Staff or any other party files a timely objection to the activities to be undertaken by DEC or PEC, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than two weeks after the objection is filed, and shall recommend that the Commission issue an order deciding how to proceed as to the objection. The Commission reserves the right to extend an advance notice period by order should the Commission need additional time to deliberate or investigate any issue. At the end of the notice period, if no order, whether procedural or substantive, has been issued, DEC, PEC, Duke Energy, any other Affiliate, or the Nonpublic Utility

Operation may proceed with the activity to be undertaken, but shall be subject to any fully-adjudicated Commission order on the matter.

(i) If the Commission schedules a hearing on an objection, the party filing the objection shall bear the burden of proof at the hearing.

(j) The precedential effect of advance notice proceedings, like most issues of res judicata, will be decided on a fact-specific basis.

(k) If some other Commission filing or Commission approval is required by statute, notice pursuant to a Regulatory Condition alone does not satisfy the statutory requirement.

(l) DEC, PEC, the Public Staff, or any party may move for a waiver if exigent circumstances in a particular case justify such.

SECTION XIV
COMPLIANCE WITH CONDITIONS AND CODE OF CONDUCT

The following Regulatory Conditions are intended to ensure that Duke Energy, DEC, PEC, and all other Affiliates establish and maintain the structures and processes necessary to fulfill the commitments expressed in all of the Regulatory Conditions and the Code of Conduct in a timely, consistent, and effective manner.

14.1 <u>Ensuring Compliance with Regulatory Conditions and Code of Conduct</u>. Duke Energy, DEC, PEC, and all other Affiliates shall devote sufficient resources into the creation, monitoring, and ongoing improvement of effective internal compliance programs to ensure compliance with all Regulatory Conditions and the DEC/PEC Code of Conduct, and shall take a proactive approach toward correcting any violations and reporting them to the Commission. This effort shall include the implementation of systems and protocols for monitoring, identifying, and correcting possible violations, a management culture that encourages compliance among all personnel, and the tools and training sufficient to enable employees to comply with Commission requirements.

14.2 <u>Designation of Chief Compliance Officer</u>. DEC and PEC shall designate a chief compliance officer who will be responsible for compliance with the Regulatory Conditions and Code of Conduct. This person’s name and contact information must be posted on DEC’s and PEC’s Internet Website.

14.3 <u>Annual Training</u>. DEC and PEC shall provide annual training on the requirements and standards contained within the Regulatory Conditions and Code of Conduct to all of their employees (including service company employees) whose duties in any way may be affected by such requirements and standards. New employees must receive such training within the first 60 days of their employment. Each employee who has taken the training must certify electronically or in writing that s/he has completed the training.

14.4 Report of Violations. If DEC and PEC discover that a violation of their requirements or standards contained within the Regulatory Conditions and Code of Conduct has occurred then DEC and PEC shall file a statement with the Commission in Docket Nos. E-7, Sub 986C, and E-2, Sub 998C, respectively, describing the circumstances leading to that violation of DEC's or PEC's requirements or standards, as contained within the Regulatory Conditions and Code of Conduct, and the mitigating and other steps taken to address the current or any future potential violation.

CODE OF CONDUCT

GOVERNING THE RELATIONSHIPS, ACTIVITIES, AND TRANSACTIONS BETWEEN AND AMONG THE PUBLIC UTILITY OPERATIONS OF DEC, THE PUBLIC UTILITY OPERATIONS OF PEC, DUKE ENERGY CORPORATION, OTHER AFFILIATES, AND THE NONPUBLIC UTILITY OPERATIONS OF DEC AND PEC

I. DEFINITIONS

For the purposes of this Code of Conduct, the terms listed below shall have the following definitions:

Affiliate: Duke Energy and any business entity of which ten percent (10%) or more is owned or controlled, directly or indirectly, by Duke Energy. For purposes of this Code of Conduct, Duke Energy and any business entity controlled by it are considered to be Affiliates of each other and DEC and PEC are considered to be Affiliates of each other.

Commission: The North Carolina Utilities Commission.

Confidential Systems Operation Information: Nonpublic information that pertains to Electric Services provided by DEC or PEC, including but not limited to information concerning electric generation, transmission, distribution, or sales.

Customer: Any retail electric customer of DEC or PEC in North Carolina.

Customer Information: Non-public information or data specific to a Customer or a group of Customers, including, but not limited to, electricity consumption, load profile, billing history, or credit history that is or has been obtained or compiled by DEC or PEC in connection with the supplying of Electric Services to that Customer or group of Customers.

DEBS: Duke Energy Business Services, LLC, and its successors, which is a service company Affiliate that provides Shared Services to DEC, PEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC or PEC, singly or in any combination.

DEC: Duke Energy Carolinas, LLC, the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Electric Services within DEC's North

Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Duke Energy: Duke Energy Corporation, which is the current holding company parent of DEC and PEC, and any successor company.

Electric Services: Commission-regulated electric power generation, transmission, distribution, delivery, and sales, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, standby service, backups, and changeovers of service to other suppliers.

Fuel and Purchased Power Supply Services: All fuel for generating electric power and purchased power obtained by DEC or PEC from sources other than DEC or PEC for the purpose of providing Electric Services.

Fully Distributed Cost: All direct and indirect costs, including overheads and an appropriate cost of capital, incurred in providing goods or services to another business entity; provided, however, that (a) for each good and service supplied by DEC or PEC, the return on common equity utilized in determining the appropriate cost of capital shall equal the return on common equity authorized by the Commission in the supplying utility’s most recent general rate case proceeding; (b) for each good and service supplied to DEC or PEC, the appropriate cost of capital shall not exceed the overall cost of capital authorized in the supplying utility’s most recent general rate case proceeding; and (c) for each good and service supplied by DEC and PEC to each other, the return on common equity utilized in determining the appropriate cost of capital shall not exceed the lower of the returns on common equity authorized by the Commission in DEC’s and PEC’s most recent general rate case proceedings.

JDA: Joint Dispatch Agreement, which is the agreement as filed with the Commission on April 1, 2011, and as revised and filed on April 4, 2011, in Docket Nos. E-7, Sub 980, and E-2, Sub 995, and allowed by the Commission to be filed with the FERC, by Order dated April 4, 2011, and as further revised and filed on June 22, 2011, and allowed to be filed with the FERC by Order dated July 11, 2011, in Docket Nos. E-7, Sub 986, and E-2, Sub 998.

Market Value: The price at which property, goods, and services would change hands in an arm's length transaction between a buyer and a seller without any compulsion to engage in a transaction, and both having reasonable knowledge of the relevant facts.

Merger: All transactions contemplated by the Agreement and Plan of Merger between Duke Energy and Progress Energy.

Natural Gas Services: Natural gas sales and natural gas transportation, and other related services, including, but not limited to, metering and billing.

Nonpublic Utility Operations: All business operations engaged in by DEC or PEC involving activities (including the sales of goods or services) that are not regulated by the Commission, or otherwise subject to public utility regulation at the state or federal level.

Non-Utility Affiliate: Any Affiliate, including DEBS and PESC, other than a Utility Affiliate, DEC, or PEC.

PEC: Progress Energy Carolinas, Inc., the business entity, wholly owned by Duke Energy, that holds the franchises granted by the Commission to provide Electric Services within the North Carolina service territory of PEC and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Personnel: An employee or other representative of DEC, PEC, Duke Energy, another Affiliate, or a Nonpublic Utility Operation, who is involved in fulfilling the business purpose of that entity.

PESC: Progress Energy Services Company and its successors, which is a service company Affiliate that provides Shared Services to PEC, DEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC or PEC, individually or in combination.

Progress Energy: Progress Energy, Inc., which is the former holding company parent of PEC, and which became a subsidiary of Duke Energy after the close of the Merger, and any successors.

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

Regulatory Conditions: The conditions imposed by the Commission in connection with or related to the Merger.

Shared Services: The services that meet the requirements of the Regulatory Conditions approved in Docket Nos. E-7, Sub 986, and E-2, Sub 998, or subsequent orders of the Commission and that the Commission has explicitly authorized DEC or PEC to take from DEBS or PESC pursuant to a service agreement (a) filed with the Commission pursuant to G.S. 62-153(b), thus requiring acceptance and authorization by the Commission, and (b) subject to all other applicable provisions of North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

Utility Affiliates: The regulated public utility operations of Duke Energy Indiana, Inc. (Duke Indiana), Duke Energy Kentucky, Inc. (Duke Kentucky), and Florida Power Corporation, d/b/a Progress Energy Florida (PEF); and the regulated transmission and distribution operations of Duke Energy Ohio, Inc. (Duke Ohio).

II. GENERAL

This Code of Conduct establishes the minimum guidelines and rules that apply to the relationships, transactions, and activities involving the public utility operations of DEC, PEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC and PEC, to the extent such relationships, activities, and transactions affect the operations or costs of utility service experienced by the public utility operations of DEC and PEC in their respective service areas. DEC, PEC, and the other Affiliates are bound by this Code of Conduct pursuant to Regulatory Condition 6.1 approved by the Commission in Docket Nos. E-2, Sub 998, and E-7, Sub 986. This Code of Conduct is subject to modification by the Commission as the public interest may require, including, but not limited to, addressing changes in the organizational structure of DEC, PEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations; changes in the structure of the electric industry; or other changes that warrant modification of this Code.

DEC or PEC may seek a waiver of any aspect of this Code of Conduct by filing a request with the Commission showing that exigent circumstances in a particular case justify such a waiver.

III. STANDARDS OF CONDUCT

A. Independence and Information Sharing

1. Separation - DEC, PEC, Duke Energy, and the other Affiliates shall operate independently of each other and in physically separate locations to the maximum extent practicable. DEC, PEC, Duke Energy, and each of the other Affiliates shall maintain separate books and records. Each of DEC's and PEC's Nonpublic Utility Operations shall maintain separate records from those of DEC's and PEC's public utility operations to ensure appropriate cost allocations and any arm's-length-transaction requirements.

2. Disclosure of Customer Information:

(a) Upon request, and subject to the restrictions and conditions contained herein, DEC and PEC may provide Customer Information to Duke Energy, another Affiliate, or a Nonpublic Utility Operation under the same terms and conditions that such information is provided to non-Affiliates.

(b) Except as provided in Section III.A.2.(f) below, Customer Information shall not be disclosed to any person or company, without the Customer's consent, and then only to the extent specified by the Customer. Consent to disclosure of Customer Information to Affiliates or Nonpublic Utility Operations may be obtained by means of written authorization, electronic authorization or recorded verbal authorization upon providing the Customer with the information set forth in Attachment A; provided, however, that DEC and PEC retain such authorization for verification purposes for as long as the authorization remains in effect.

(c) If the Customer allows or directs DEC or PEC to provide Customer Information to Duke Energy, another Affiliate, or a Nonpublic Utility Operation, then DEC or PEC shall ask the Customer if he, she, it would like the Customer Information to be provided to one or more non-Affiliates. If the Customer directs DEC or PEC to provide Customer Information to one or more non-Affiliates, the Customer Information shall be disclosed to all entities designated by the Customer contemporaneously and in the same manner.

(d) Sections III.A.2.(a), 2.(b), and 2.(c) herein shall be permanently posted on DEC's and PEC’s website.

(e) No DEC or PEC employee who is transferred to Duke Energy or another Affiliate will be permitted to copy or otherwise compile any Customer Information for use by such entity except pursuant to written permission from the Customer, as reflected by a signed Data Disclosure Authorization. Neither DEC nor PEC shall transfer any employee to Duke Energy or another Affiliate for the purpose of disclosing or providing Customer Information to such entity.

(f) Notwithstanding the prohibitions established by this Section III.A.2, DEC and PEC may disclose Customer Information to DEBS, PESC, any other Affiliate, a Nonpublic Utility Operation or a non-affiliated third party without Customer consent, but only to the extent necessary for the Affiliate, Nonpublic Utility Operation or non-affiliated third party to provide goods or services to DEC or PEC and upon their explicit agreement to protect the confidentiality of such Customer Information. To the extent the Commission approves a list of services to be provided and taken pursuant to one or more utility-to-utility service agreements, then Customer Information may be disclosed pursuant to the foregoing exception to the extent necessary for such services to be performed.

(g) DEC and PEC shall take appropriate steps to store Customer Information in such a manner as to limit access to only those persons permitted to receive it and shall require all persons with access to such information to protect its confidentiality.

(h) DEC and PEC shall establish guidelines for its employees and representatives to follow with regard to complying with this Section III.A.2.

(i) No DEBS or PESC employee may use Customer Information to market or sell any product or service to DEC’s or PEC’s Customers, except in support of a Commission-approved rate schedule or program or a marketing effort managed and supervised directly by DEC or PEC.

(j) DEBS and PESC employees with access to Customer Information must be prohibited from making any improper indirect use of the data, including directing or encouraging any actions based on the Customer Information by employees of DEBS or PESC that do not have access to such information, or by other employees of Duke Energy or other Affiliates or Nonpublic Utility Operations of the Utilities.

(k) Should any inappropriate disclosure of DEC or PEC Customer Information occur at any time, DEC or PEC is required to promptly file a statement with the Commission in this docket describing the circumstances of the disclosure, the Customer information disclosed, the results of the disclosure, and the mitigating and/or other steps taken to address the disclosure.

3. The disclosure of Confidential Systems Operation Information of DEC and PEC (referred to hereinafter as "Information") shall be governed as follows:

(a) Such Information shall not be disclosed by DEC or PEC to an Affiliate or a Nonpublic Utility Operation unless it is disclosed to all competing non-Affiliates contemporaneously and in the same manner. Disclosure to non-Affiliates is not required when disclosure to Affiliates or Nonpublic Utility Operations meets one of the following exceptions:

(i) The Information is provided to employees of DEC or PEC for the purpose of implementing, and operating pursuant to, the JDA in accordance with the Regulatory Conditions approved in Docket Nos. E-7, Sub 986, and E-2, Sub 998;

(ii) The Information is necessary for the performance of services approved to be performed pursuant to one or more Affiliate utility-to-utility service agreements;

(iii) A state or federal regulatory agency or court having jurisdiction over the disclosure of the Information requires the disclosure;

(iv) The Information is provided to employees of DEBS or PESC pursuant to a service agreement filed with the Commission pursuant to G.S. 62-153;

(v) The Information is provided to employees of DEC's or PEC's Utility Affiliates for the purpose of sharing best practices and otherwise improving the provision of regulated utility service;

(vi) The Information is provided to an Affiliate pursuant to an agreement filed with the Commission pursuant to G.S. 62-153, provided that the agreement specifically describes the types of Information to be disclosed;

(vii) Disclosure is otherwise essential to enable DEC or PEC to provide Electric Services to their Customers; or

(viii) Disclosure of the Information is necessary for compliance with the Sarbanes-Oxley Act of 2002.

(b) Any Information disclosed pursuant to the exceptions in Section III.A.3(a), above, shall be disclosed only to employees that need the information for the purposes covered by those exceptions and in as limited a manner as possible. The employees receiving such Information must be prohibited from acting as conduits to pass the Information to any Affiliate(s) and must have explicitly agreed to protect the confidentiality of such Information.

(c) For disclosures pursuant to exceptions (vii) and (viii) in Section III.A.3(a), above, DEC and PEC shall include in their annual affiliated transaction reports the following information:

(i) The types of Information disclosed and the name(s) of the Affiliate(s) to which it is being, or has been, disclosed;

(ii) The reasons for the disclosure; and

(iii) Whether the disclosure is intended to be a one-time occurrence or an ongoing process.

To the extent a disclosure subject to the reporting requirement is intended to be ongoing, only the initial disclosure and a description of any processes governing subsequent disclosures need to be reported.

(d) DEC, PEC, DEBS, and PESC employees with access to CSOI must be prohibited from making any improper indirect use of the data, including directing or encouraging any actions based on the CSOI by employees that do not have access to such information, or by other employees of Duke Energy or other Affiliates or Nonpublic Utility Operations of DEC and PEC.

(e) Should the handling or disclosure of Market Information, Transmission Information, or other CSOI by DEBS, PESC, or another Affiliate or Nonpublic Utility Operation, or their respective employees, result in (i) a violation of DEC's or PEC's FERC Statement of Policy and Code of Conduct (FERC Code), 18 CFR 358 - Standards of Conduct for Transmission Providers (Transmission Standards), or any other relevant FERC standards or codes of conduct, (ii) the posting of such data on an OASIS or other Internet website, or (iii) other public disclosure of the data, DEC or PEC shall promptly file a statement with the Commission in Commission in Docket Nos. E-7, Sub 986C, and E-2, Sub 998C, respectively, describing the circumstances leading to such violation, posting, or other this docket describing the circumstances leading to such violation, posting, or other public disclosure, any data required to be posted or otherwise publicly disclosed, and the mitigating and/or other steps taken to address the current or any future potential violation, posting, or other public disclosure.

(f) Should any inappropriate disclosure of CSOI occur at any time, DEC or PEC shall promptly file a statement with the Commission in Docket Nos. E-7, Sub 986C, or E-2, Sub 998C, respectively, describing the circumstances of the disclosure, the CSOI disclosed, the results of the disclosure, and the mitigating and/or other steps taken to address the disclosure.

(g) Unless publicly noticed and generally available, should the FERC Code, the Transmission Standards, or any other relevant FERC standards or codes of conduct be eliminated, amended, superseded, or otherwise replaced, DEC and PEC shall file a letter in Docket Nos. E-7, Sub 986E, and E-2, Sub 998E, with the Commission describing such action within 60 days of the action, along with a copy of any amended or replacement document.

B. Nondiscrimination

1. DEC's and PEC's employees and representatives shall not unduly discriminate against non-Affiliated entities.

2. In responding to requests for Electric Services, neither DEC nor PEC shall provide any preference to Duke Energy, another Affiliate, or a Nonpublic Utility Operation, nor to any customers of such an entity, as compared to non-Affiliates or their customers. Moreover, neither DEC, PEC, Duke Energy, nor any other Affiliates shall represent to any person or entity that Duke Energy, another Affiliate, or a Nonpublic Utility Operation will receive any such preference.

3. DEC and PEC shall apply the provisions of their respective tariffs equally to Duke Energy, the other Affiliates, the Nonpublic Utility Operations, and non-Affiliates.

4. DEC and PEC shall process all similar requests for Electric Services in the same timely manner, whether requested on behalf of Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity.

5. No personnel or representatives of DEC, PEC, Duke Energy, or another Affiliate shall indicate, represent, or otherwise give the appearance to another party that Duke Energy or another Affiliate speaks on behalf of DEC or PEC; provided however, that this prohibition shall not apply to employees of DEBS or PESC providing Shared Services or to employees of another Affiliate to the extent explicitly provided for in an affiliate agreement that has been accepted by the Commission. In addition, no personnel or representatives of a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that they speak on behalf of DEC's or PEC's regulated public utility operations.

6. No personnel or representatives of DEC, PEC, Duke Energy, another Affiliate, or a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that any advantage to that party with regard to Electric Services exists as the result of that party dealing with Duke Energy, another Affiliate, or a Nonpublic Utility Operation, as compared with a non-Affiliate.

7. Neither DEC nor PEC shall condition or otherwise tie the provision or terms of any Electric Services to the purchasing of any goods or services from, or the engagement in business of any kind with, Duke Energy, another Affiliate, or a Nonpublic Utility Operation.

8. When any employee or representative of DEC or PEC receives a request for information from or provides information to a Customer about goods or services available from Duke Energy, another Affiliate, or a Nonpublic Utility Operation, the employee or representative shall advise the Customer that such goods or services may also be available from non-Affiliated suppliers.

9. Disclosure of Customer Information to Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity shall be governed by Section III.A.2 of this Code of Conduct.

C. Marketing

1. The public utility operations of DEC and PEC may engage in joint sales, joint sales calls, joint proposals, or joint advertising (a joint marketing arrangement) with their Utility Affiliates and with their Nonpublic Utility Operations, subject to compliance with other provisions of this Code of Conduct and any conditions or restrictions that the Commission may hereafter establish. Neither DEC nor PEC shall otherwise engage in such joint activities without making such opportunities available to comparable third parties.

2. Neither Duke Energy nor any of the other Affiliates shall use the names or logos of DEC or PEC in any communications unless a disclaimer is included that states the following:

(a) "[Duke Energy Corporation/Affiliate) is not the same company as [DEC/PEC], and [Duke Energy Corporation/Affiliate) has separate management and separate employees”;

(b) "[Duke Energy Corporation/Affiliate] is not regulated by the North Carolina Utilities Commission or in any way sanctioned by the Commission";

(c) "Purchasers of products or services from [Duke Energy Corporation/Affiliate] will receive no preference or special treatment from [DEC/PEC]"; and

(d) "A customer does not have to buy products or services from [Duke Energy Corporation/Affiliate] in order to continue to receive the same safe and reliable electric service from [DEC/PEC]."

3. Nonpublic Utility Operations may not use the names or logos of DEC or PEC in any communications unless a disclaimer is included that states the following:

(a) "[Nonpublic Utility Operation] is not part of the regulated services offered by [DEC/PEC] and is not in any way sanctioned by the North Carolina Utilities Commission";

(b) "Purchasers of products or services from [Nonpublic Utility Operation] will receive no preference or special treatment from [DEC/PEC]"; and

(c) "A customer does not have to buy products or services from [Nonpublic Utility Operation] in order to continue to receive the same safe and reliable electric service from [DEC/PEC]."

The required disclaimer must be sized and displayed in a way that is commensurate with the name and logo so that the disclaimer is at least the larger of one-half the size of the type that first displays the name and logo or the predominant type used in the communication.

D. Transfers of Goods and Services, Transfer Pricing, and Cost Allocation

1. Cross-subsidies involving DEC or PEC and Duke Energy, other Affiliates, or the Nonpublic Utility Operations are prohibited.

2. All costs incurred by personnel or representatives of DEC or PEC for or on behalf of Duke Energy, other Affiliates, or the Nonpublic Utility Operations shall be charged to the entity responsible for the costs.

3. As a general guideline, with regard to the transfer prices charged for goods and services, including the use or transfer of personnel, exchanged between and among DEC or PEC, and Duke Energy, the other Non-Utility Affiliates, and the Nonpublic Utility Operations, to the extent such prices affect DEC's or PEC's operations or costs of utility service, the following conditions shall apply:

(a) Except as otherwise provided for in this Section III.D, for untariffed goods and services provided by DEC or PEC to Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, the transfer price paid to DEC or PEC shall be set at the higher of Market Value or DEC's or PEC's Fully Distributed Cost.

(b) Except as otherwise provided for in this Section III.D, for goods and services provided, directly or indirectly, by Duke Energy, a Non-Utility Affiliate other than DEBS or PESC, or a Nonpublic Utility Operation to DEC or PEC, the transfer price(s) charged by Duke Energy, the Non-Utility Affiliate, and the Nonpublic Utility Operation to DEC or PEC shall be set at the lower of Market Value or Duke Energy's, the Non-Utility

Affiliate's, or the Nonpublic Utility Operation's Fully Distributed Cost(s). If DEC or PEC do not engage in competitive solicitation and instead obtain the goods or services from Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, DEC and PEC shall implement adequate processes to comply with this Code provision and related Regulatory Conditions and ensure that in each case DEC's and PEC's Customers receive service at the lowest reasonable cost. For goods and services provided by DEBS and PESC to DEC, PEC, and Utility Affiliates, the transfer price charged shall be set at DEBS' and PESC's Fully Distributed Cost.

(c) Tariffed goods and services provided by DEC and PEC to Duke Energy, other Affiliates, or a Nonpublic Utility Operation shall be provided at the same prices and terms that are made available to Customers having similar characteristics with regard to Electric Services (such as time of use, manner of use, customer class, load factor, and relevant Standard Industrial Classification) under the applicable tariff.

(d) Subject to and in compliance with all conditions placed upon DEC and PEC by the Commission, untariffed non-power, non-generation, or non-fuel goods and services provided by DEC or PEC to DEC, PEC, or the Utility Affiliates or by the Utility Affiliates to DEC or PEC, shall be transferred at the supplier's Fully Distributed Cost.

4. To the extent that DEC, PEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations receive Shared Services from DEBS or PESC (or their successors), these Shared Services may be jointly provided to DEC, PEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations on a fully distributed cost basis, provided that the taking of such Shared Services by DEC and PEC is cost beneficial on a service-by-service (e.g., accounting management, human resources management, legal services, tax administration, public affairs) basis to DEC and PEC. Charges for such Shared Services shall be allocated in accordance with the cost allocation manual(s) filed with the Commission pursuant to Regulatory Condition 5.5, subject to any revisions or other adjustments that may be found appropriate by the Commission on an ongoing basis.

5. DEC, PEC, and their Utility Affiliates may capture economies-of-scale in joint purchases of goods and services (excluding the purchase of natural gas, coal, and electricity or ancillary services intended for resale), if such joint purchases result in cost savings to DEC's and PEC's Customers. DEC, PEC, Duke Indiana, Duke Kentucky, and PEF, may capture economies-of-scale in joint purchases of coal and natural gas, if such joint purchases result in cost savings to DEC's and PEC's Customers. Notwithstanding the foregoing, if any of the coal or natural gas jointly purchased by DEC, PEC, Duke Indiana, Duke Kentucky, or PEF is transferred to or utilized by another Affiliate within 12 months of the joint purchase, DEC and PEC will file a notification of such with the Commission. All joint purchases entered into pursuant to this section shall be priced in a manner that permits clear identification of each participant's portion

of the purchases and shall be reported in DEC's and PEC's affiliated transaction reports filed with the Commission.

6. All permitted transactions between DEC, PEC, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall be recorded and accounted for in accordance with the cost allocation manuals required to be filed with the Commission pursuant to Regulatory Condition 5.5 and with Affiliate agreements accepted by the Commission or otherwise processed in accordance with North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

7. Costs that DEC and PEC incur in assembling, compiling, preparing, or furnishing requested Customer Information or Confidential Systems Operation Information for or to Duke Energy, other Affiliates, Nonpublic Utility Operations, or non-Affiliates shall be recovered from the requesting party pursuant to Section III.D.3 of this Code of Conduct.

8. Any technology or trade secrets developed, obtained, or held by DEC or PEC in the conduct of regulated operations shall not be transferred to Duke Energy, another Affiliate, or a Nonpublic Utility Operation without just compensation and the filing of 60-days prior notification to the Commission; provided however, that DEC and PEC are not required to provide advance notice for such transfers to each other. DEC and PEC may request a waiver of this requirement from the Commission with respect to such transfers to Duke Energy, a Utility Affiliate, a Non-Utility Affiliate, or a Nonpublic Utility Operation. In no case, however, shall the notice period requested be less than 20 business days.

9. DEC and PEC shall receive compensation from Duke Energy, other Affiliates, and the Nonpublic Utility Operations for intangible benefits, if appropriate.

E. Regulatory Oversight

1. The State's existing requirements regarding affiliate transactions, as set forth in G.S. 62-153, shall continue to apply to all transactions between DEC, PEC, Duke Energy, and the other Affiliates.

2. The books and records of DEC, PEC, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall be open for examination by the Commission, its staff, and the Public Staff as provided in G.S. 62-34, 62-37, and 62-51.

3. To the extent North Carolina law, the orders and rules of the Commission, and the Regulatory Conditions permit Duke Energy, an Affiliate, or a Nonpublic Utility Operation to supply DEC or PEC with Natural Gas Services or other Fuel and Purchased Power Supply Services used by DEC or PEC to provide Electric Services to Customers, and to the extent such Natural Gas Services or other Fuel and Purchased Power Supply Services are supplied, DEC or PEC shall demonstrate in its annual fuel adjustment clause proceeding that each such acquisition was prudent and the price was reasonable.

F. Utility Billing Format

To the extent any bill issued by DEC and PEC, Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party includes any charges to Customers for Electric Services and non-Electric Services from Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party, the charges for the Electric Services shall be separated from the charges for any other services included on the bill. Each such bill shall contain language stating that the Customer's Electric Services will not be terminated for failure to pay for any other services billed.

G. Complaint Procedure

1. DEC and PEC shall establish complaint procedures to resolve potential complaints that arise due to the relationship of DEC and PEC with Duke Energy, its other Affiliates, and its Nonpublic Utility Operations. The complaint procedures shall provide for the following:

(a) Verbal and written complaints shall be referred to a designated representative of DEC or PEC.

(b) The designated representative shall provide written notification to the complainant within 15 days that the complaint has been received.

(c) DEC or PEC shall investigate the complaint and communicate the results or status of the investigation to the complainant within 60 days of receiving the complaint.

(d) DEC and PEC shall each maintain a log of complaints and related records and permit inspection of documents (other than those protected by the attorney/client privilege) by the Commission, its staff, or the Public Staff.

2. Notwithstanding the provisions of Section III.G.1, any complaints received through Duke Energy's EthicsLine (or successor), which is a confidential mechanism available to the employees of the Duke Energy holding company system, shall be handled in accordance with procedures established for EthicsLine.

3. These complaint procedures do not affect a complainant's right to file a formal complaint or otherwise address questions to the Commission.

CODE OF CONDUCT
ATTACHMENT A

DEC/PEC CUSTOMER INFORMATION DISCLOSURE AUTHORIZATION

For Disclosure to Affiliates:

DEC's/PEC's Affiliates offer products and services that are separate from the regulated services provided by DEC/PEC. These services are not regulated by the North Carolina Utilities Commission or the Public Service Commission of South Carolina. These products and services may be available from other competitive sources.

The Customer authorizes DEC/PEC to provide any data associated with the Customer account(s) residing in any DEC/PEC files, systems or databases **[or specify specific types of data]** to the following Affiliate(s) ______________________. DEC/PEC will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

For Disclosure to Nonpublic Utility Operations:

DEC/PEC offers optional, market-based products and services that are separate from the regulated services provided by DEC/PEC. These services are not regulated by the North Carolina Utilities Commission or the Public Service Commission of South Carolina. These products and services may be available from other competitive sources.

The Customer authorizes DEC/PEC to use any data associated with the Customer account(s) residing in any DEC/PEC files, systems or databases **[or specify types of data]** for the purpose of offering and providing energy-related products or services to the Customer. DEC/PEC will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

DOCKET NO. E-7, SUB 1017

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Investigation Regarding the Approval and Closing of the Business Combination of Duke Energy Corporation and Progress Energy, Inc.	))))	ORDER APPROVING SETTLEMENT AGREEMENT AND CLOSING INVESTIGATION

BY THE COMMISSION: On April 4, 2011, Duke Energy Corporation (Duke), and Progress Energy, Inc. (Progress, collectively Applicants), filed an application in Docket Nos. E-2, Sub 998 and E-7, Sub 986 (Merger Docket), requesting that the Commission approve their proposed merger. In the merger application and in testimony at an evidentiary hearing before the Commission on September 20, 2011, Duke and Progress represented to the Commission that, effective upon the closing of the merger, William D. Johnson, then President, Chief Executive Officer (CEO), and Executive Chairman of the Board of Directors of Progress, would be the President and CEO of the combined company and that James E. Rogers, then President, CEO and Executive Chairman of the Board of Directors of Duke, would be the Executive Chairman of the Board of the combined company.

On June 25, 2012, the Commission held a further evidentiary hearing in the Merger Docket to provide the parties the opportunity to address changes in circumstances following the evidentiary hearing in September 2011.

On June 29, 2012, the Commission issued an Order Approving Merger Subject to Regulatory Conditions and Code of Conduct (Merger Order).

On July 2, 2012, Duke and Progress closed the merger transaction.

On July 3, 2012, Duke announced that Rogers would replace Johnson as President and CEO of Duke. The Commission was not informed by Duke or Progress at any time prior to July 3, 2012, that Rogers would replace Johnson as President and CEO of Duke.

On July 6, 2012, the Commission issued an Order Initiating Investigation and Scheduling Hearing in the above-captioned docket (Investigation Docket). The Order scheduled a hearing before the Commission on July 10, 2012, directed Rogers to appear at the hearing and answer the Commission's questions and ordered Duke and Progress to take all necessary actions to preserve all letters, agreements, notes, minutes, memos, emails, and other written and recorded documents and records directly or indirectly relating in any way to the merger, the integration of the two companies and the discussions and decision to replace Johnson with Rogers as President and CEO of Duke.

On July 10, 2012, the North Carolina Waste Awareness and Reduction Network, Inc. (NC WARN), filed a Motion to Intervene and Initial Scoping Comments in the Investigation Docket, which was denied by Order issued July 13, 2012.

On July 10, 2012, Rogers appeared at a hearing before the Commission and testified regarding the approval and closing of the merger and his replacement of Johnson as the President and CEO of Duke. On July 11, 2012, Duke filed a Statement of James E. Rogers.

On July 12, 2012, the Commission issued an Order Scheduling Hearing and Requiring Production of Documents in the Investigation Docket. The Order required Johnson, E. Marie McKee and James B. Hyler, Jr. to appear before the Commission on July 19, 2012, and required Ann M. Gray and Michael G. Browning to appear before the Commission on July 20, 2012, to provide testimony addressing the timing of the decision to replace Johnson with Rogers, as well as other related matters. Further, the Order directed Duke to produce documents specified therein for the Commission's inspection. The Commission subsequently retained the law firm of Jenner & Block as outside counsel to assist the Commission Staff in conducting this investigation.

On July 17, 2012, Duke filed a Motion in Objection to Order Scheduling Hearing in which Duke, among other things, requested that the hearing scheduled to be held on July 20, 2012, be continued. Attached to the motion was a document entitled Statement of Ann Gray. On July 18, 2012, the Commission issued an Order Denying Motion to Continue Hearing.

On July 19 and 20, 2012, Johnson, McKee, Hyler, Gray and Browning appeared at hearings before the Commission and testified regarding the approval and closing of the merger and the replacement of Johnson by Rogers as the President and CEO of Duke.

On August 7 and 21, 2012, a total of 5,964 pages of documents were filed by Duke and the legacy Progress directors in response to the Commission's July 12, 2012 Order, most of which were filed under seal as confidential trade secrets. On October 19, 2012, the Commission issued an Order on Public Records Act Requests finding that only certain of these pages filed under seal contain trade secret information that is exempt from public disclosure under the trade secret exception to the Public Records Act, G.S.132-1.2 (PRA).

On or about November 5, 2012, Duke and the legacy Progress directors filed most of the documents required by the Commission's October 19, 2012 Order. However, Duke filed a Notice of Appeal and Exceptions (Notice of Appeal) to the North Carolina Court of Appeals challenging the Commission's Order with regard to information contained in 443 pages or portions of pages ordered to be made public. In addition, Duke challenges the Commission's Order with regard to information contained in 199 pages of documents that the Commission ordered to be made public by the legacy Progress directors. Further, the legacy Progress directors filed a motion for reconsideration regarding the information contained in 11 pages of the documents that the Commission ordered to be made public.

On November 29, 2012, the Commission Staff, the Public Staff and Duke (Settling Parties) filed a Settlement Agreement in this docket. In summary, the Settlement Agreement recounts the procedural history of the Investigation Docket, states several actions Duke agrees to take, and recommends that the Commission accept the actions by Duke as a complete resolution of all issues in the Merger and Investigation Dockets. The actions to be taken by Duke are as follows:

- Duke will maintain at least one thousand (1,000) employees, including the President of Duke Energy North Carolinas and the Senior Vice-President of Carolinas Delivery Operations, in Raleigh for at least five (5) years.

- Duke's Board of Directors will create and maintain a new committee entitled the Regulatory Policy and Operations Committee (RPOC). The RPOC will meet with the Commission periodically to receive comments from the Commission on the activities and actions of the Duke Board and report back to the Board on its meetings with the Commission and the Commission's comments.

- Duke will guarantee that Duke's North Carolina retail ratepayers will receive an additional $25 million in fuel and fuel-related cost savings over and above the amount that Duke is obligated to provide pursuant to the Commission's Order approving the merger.

- Duke will contribute an additional $5 million to workforce development and low-income assistance in North Carolina over and above the amount that Duke is obligated to provide pursuant to the Commission's Order approving the merger.

- Duke will defer filing a general rate case by Duke Energy Carolinas, LLC (DEC), in North Carolina until February 2013, with the understanding that DEC will be allowed to defer the depreciation and operating costs of new generation incurred from the commercial operation of such new generation until the effective date of new base rates. In addition, DEC will be allowed to levelize its nuclear costs.

- Duke will make several changes in its top management positions, including naming a new General Counsel and Executive Vice-President for Regulated Utilities, and retaining the former Progress General Counsel as an advisor on regulatory and legislative matters. In addition, Rogers will retire on December 31, 2013, as he originally planned to do in conjunction with the merger.

- Duke's Board will create a CEO and Board Member Search Committee (CEOBM), with a balanced number of former Duke and former Progress board members, plus a new Board member not previously affiliated with either company. The CEOBM will recommend candidates for the CEO and new Board member positions.

- As current legacy Duke board members reach the conclusion of their appointed terms and the mandatory retirement age of 71 during 2013 through 2016, those board members will rotate off the Board. However, the Board term of Dr. James Rhodes may be extended for two (2) years beyond his mandatory retirement age based on his expertise with regard to the Company's nuclear generation fleet.

- Duke will pay all fees and expenses billed by Jenner & Block and will not seek to recover any part of such fees from its North Carolina retail ratepayers. Jenner & Block will cease all activity in the Investigation Docket.

- Duke will pay all severance costs associated with the departure of Johnson and other top Progress executives and will not seek to recover any part of such costs from its North Carolina retail ratepayers.

- Duke will issue a statement to the Commission acknowledging that its activities have fallen short of the Commission's understanding of Duke's obligations under its regulatory compact that frame the duties for a regulated utility in North Carolina.

The Settlement Agreement states that it is the product of negotiation and compromise on numerous complex factual and legal issues, and that Duke specifically denies that it has engaged in any unlawful or improper actions. Further, the Settling Parties recommend that the Commission issue such orders within the Commission's authority as are necessary to terminate the investigation and close the Merger and Investigation Dockets.

The Commission Staff presented this matter to the Commission at its Regular Staff Conference on December 3, 2012. The Commission Staff stated that it considers the Settlement Agreement to be in the public interest as an appropriate and reasonable mechanism to resolve the Commission's investigation in a manner that is fair to all parties. In particular, the Commission Staff stated that the Settlement Agreement accomplishes the following primary objectives: (1) to affirm the integrity of North Carolina's public utility regulatory process; (2) to require that Duke's shareholders, not Duke's North Carolina retail ratepayers, bear the cost of the Commission's investigation and pay all severance costs associated with the departure of Johnson and other top Progress executives; (3) to provide a substantial monetary benefit to Duke's North Carolina retail ratepayers through an additional $25 million in fuel and fuel-related cost savings and $5 million in workforce development and low-income assistance; (4) to restore the balance between Duke and Progress in the merged company as originally represented, before Bill Johnson's termination and the departure of other key Progress executives; (5) to provide stability that will enable the combined company's employees to focus their efforts on performing their important work for customers, as well as benefit shareholders, lenders, contractors and other persons who have a direct interest in the success of the merger; and (6) to restore openness and trust between the Commission and Duke, its management and Board.

The Commission Staff recommended that the Commission issue an order approving the Settlement Agreement and issue such additional orders within the Commission's authority as are necessary to implement the terms of the Settlement Agreement. Representatives of the Applicants, the Attorney General, and the Public Staff appeared at the Staff Conference in support of the Commission Staff's recommendation and approval of the Settlement Agreement.

On December 11, 2012, Duke filed a letter with the Commission, pursuant to the Settlement Agreement, signed by Rogers apologizing for its actions, both in connection with the merger and subsequent to the initiation of the Commission's investigation in this docket, and acknowledging that its activities have fallen short of the Commission's understanding of Duke's obligations under its regulatory compact that frame the duties for a regulated utility in North Carolina.

DISCUSSION

The Commission was created and vested with the authority "to regulate public utilities generally, their rates, services and operations … in accordance with the policies set forth" in the Public Utilities Act, G.S. 62-2(b), including "fair regulation of public utilities in the interest of the public." G.S. 62-2(a)(1). As the courts have described this relationship, "The State has granted to the utility company a legal monopoly upon a service vital to the economic well being and the domestic life on the people of a large territory." State ex rel. Utilities Comm'n v. General Telephone Co., 281 N.C. 318, 335, 189 S.E.2d 705, 716 (1972).

> The utility business represents a compact of sorts; a monopoly on service in a particular geographical area (coupled with state-conferred rights of eminent domain or condemnation) is granted to the utility in exchange for a regime of intensive regulation, including price regulation, quite alien to the free market. Each party to the compact gets something in the bargain. As a general rule, utility investors are provided a level of stability in earnings and value less likely to be attained in the unregulated or moderately regulated sector; in turn, ratepayers are afforded universal, non-discriminatory service and protection from monopolistic profits through political control over an economic enterprise.

Jersey Cent. Power & Light Co. v. Federal Energy Regulatory Comm'n, 810 F.2d 1168, 1189 (D.C. Cir. 1987) (citations omitted). For the Commission to fulfill its role under North Carolina law and this regulatory compact, the information it receives from the public utilities it regulates must be truthful, accurate and complete. The integrity of the Commission to carry out its statutory mandate relies on the openness and honesty of the regulated public utilities, and in granting a public utility a monopolistic franchise, a presumption is created between the parties that a public utility will not engage in fraud, deception, or misrepresentation. J.P. Morgan Ventures Energy Corp., 140 FERC ¶ 61,227 (Sept. 20, 2012).

The testimony and statements by Rogers, Gray and others in this proceeding raised issues surrounding the decision to terminate Johnson and whether Duke acted with proper regard for its obligations to the State of North Carolina under the Public Utilities Act. Duke testified in September of 2011 who the CEO of the merged utility would be, and the Commission issued its Order approving the merger on June 29, 2012, assuming that still to be the case. When representations are made to the Commission with the intent that the Commission rely upon them and changes occur so that the representations are no longer accurate, it is incumbent upon the utility to set the record straight and prevent the Commission from proceeding to act upon facts that are no longer correct. The merger was presented to the Commission as the creation of a new company that would be managed and operated by a thoughtfully selected counterbalance of legacy Duke and legacy Progress personnel to ensure that former Duke and Progress employees would be treated fairly and that harmony would exist among the work force so that adequate service would be provided at reasonable rates.

CONCLUSIONS

After careful consideration, the Commission finds good cause to approve the Settlement Agreement entered into by Duke, the Public Staff and the Commission Staff. The Commission agrees with the Settling Parties that the Settlement Agreement is a reasonable and appropriate means to resolve the Commission's investigation and that its approval is in the public interest. Duke's apology and acknowledgement with regard to its obligations under the regulatory compact and the implementation of the actions agreed to by the Settling Parties to restore the balance between legacy Duke and legacy Progress in the merged company allows the merged company and the Commission to move forward, reaffirms the regulatory compact and continued public confidence in the integrity of utility regulation, and allows the merged company to focus on its mission to provide affordable, reliable electric service to North Carolina consumers.

IT IS, THEREFORE, ORDERED that the November 29, 2012 Settlement Agreement filed in this docket shall be, and is hereby, approved and that all further activities associated with this investigation shall be ceased.

ISSUED BY ORDER OF THE COMMISSION.
This the _12th_ day of December, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Bh121212.02

DOCKET NO. E-7, SUB 989

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC, for	)	
Adjustment of Rates and Charges Applicable to	)	ORDER GRANTING GENERAL
Electric Utility Service in North Carolina	)	RATE INCREASE

HEARD: Tuesday, October 11, 2011, at 7:00 p.m., in the Charlotte-Mecklenburg Government Center, Chamber Conference Room 267, 600 East Fourth Street, Charlotte, North Carolina

Tuesday, October 25, 2011, at 7:00 p.m., in the McDowell County Courthouse, Courtroom (second floor), corner of Main and Court Streets, Marion, North Carolina

Wednesday, October 26, 2011, at 7:00 p.m., in the Macon County Courthouse, Courtroom A, 5 West Main Street, Franklin, North Carolina

Thursday, October 27, 2011, at 7:00 p.m., in the High Point City Hall, Council Chambers, 211 South Hamilton Street, High Point, North Carolina

Wednesday, November 2, 2011, at 7:00 p.m., in the Durham City Hall, Council Chambers, 101 City Hall Plaza, Durham, North Carolina

Monday, November 28, 2011, at 1:00 p.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; Commissioners William T. Culpepper, III, Bryan E. Beatty, Susan W. Rabon, ToNola D. Brown-Bland, and Lucy T. Allen

APPEARANCES:

For Duke Energy Carolinas, LLC:

Heather Shirley Smith, Deputy General Counsel, Duke Energy Corporation, 550 South Tryon Street, Charlotte, North Carolina 28202

Kendrick Fentress, Associate General Counsel, Duke Energy Corporation, 3700 Glenwood Avenue, Suite 330, Raleigh, North Carolina 27612

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 3700 Glenwood Avenue, Suite 330, Raleigh, North Carolina 27612

Kiran H. Mehta, K&L Gates, LLP, 214 North Tryon Street, 47th Floor, Charlotte, North Carolina 28202

For the Using and Consuming Public:

Dianna W. Downey, Staff Attorney; David T. Drooz, Staff Attorney; Lucy E. Edmondson, Staff Attorney; Robert S. Gillam, Staff Attorney; William E. Grantmyre, Staff Attorney; Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

Margaret A. Force, Assistant Attorney General, North Carolina Department of Justice, P.O. Box 629, Raleigh, North Carolina 27602

Christopher J. Ayers, on behalf of the North Carolina Department of Justice, Poyner Spruill LLP, 301 Fayetteville Street, Suite 1900, Raleigh, North Carolina 27601

For North Carolina Waste Awareness & Reduction Network (NC WARN), North Carolina Justice Center (NCJC), and North Carolina Housing Coalition (NCHC) (collectively, NC WARN, et al.):

John D. Runkle, P.O. Box 3793, Chapel Hill, North Carolina 27515

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

Ralph McDonald, and Carson Carmichael, Bailey & Dixon, LLP, P.O. Box 1351, Raleigh, North Carolina 27602

For the Carolina Utility Customers Association, Inc. (CUCA):

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

For The Kroger Co. (Kroger):

Daniel C. Higgins, Burns, Day & Presnell, P.A., P.O. Box 10867, Raleigh, North Carolina 27605

Jody M. Kyler, Boehm, Kurtz & Lowry, 36 East Seventh Street, Suite 1510, Cincinnati, Ohio 45202

For the Commercial Group:

Alan R. Jenkins, Jenkins at Law, LLC, 2265 Roswell Road, Suite 100, Marietta, Georgia 30062

Robert C. Paschal, Young Moore and Henderson, P.A., P.O. Box 31627, Raleigh, North Carolina 27622

For Time Warner Cable, Inc. (Time Warner):

Patricia S. Cowart-Coughlan, Utility Management Services, Inc. 1221 Floral Parkway, Suite 201, Wilmington, North Carolina 28403

For the City of Durham, North Carolina (Durham):

Sherri Zann Rosenthal, Senior Assistant City Attorney, City of Durham, 101 City Hall Plaza, Durham, North Carolina 27701

BY THE COMMISSION: On June 1, 2011, pursuant to Commission Rule R1-17(a), Duke Energy Carolinas, LLC (Duke Energy Carolinas or the Company),[1] filed notice of its intent to file a general rate case application. On July 1, 2011, the Company filed its Application for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina (Application) along with a Rate Case Information Report using NCUC Form E-1 (Form E-1), and the direct testimony and exhibits of Brett C. Carter, President of Duke Energy Carolinas, North Carolina; Dhiaa M. Jamil, Group Executive and Chief Generation Officer of Duke Energy and Chief Nuclear Officer of Duke Energy Carolinas; Jim L. Stanley, Senior Vice President, Power Delivery for Duke Energy's Franchised Electric and Gas Business; Stephen G. De May, Senior Vice President Investor Relations and Treasurer of Duke Energy and an officer of Duke Energy Carolinas; Robert B. Hevert, President of Concentric Energy Advisers, Inc.; J. Danny Wiles, Vice President, Franchised Electric & Gas Accounting for Duke Energy and Vice President, Accounting, for Duke Energy Carolinas; Phillip O. Stillman, General Manager of Regulatory Accounting & Planning for Duke Energy Business Services, LLC (Duke Energy Business Services);[2] Jane L. McManeus, Managing Director, Rates, for Duke Energy Carolinas; Carol E. Shrum, Vice President, Rates, for Duke Energy Carolinas; and Jeffrey R. Bailey, Director, Pricing and Analysis for Duke Energy and its affiliated utility operating companies.

Petitions to intervene were filed by the Commercial Group on July 1, 2011, CUCA on July 11, 2011, CIGFUR III on July 11, 2011, the North Carolina Sustainable Energy Association (NCSEA) on August 19, 2011, Utility Management Services, Inc. (UMS) on August 25, 2011, NC WARN et al., on September 9, 2011, Kroger on September 23, 2011, Time Warner on October 24, 2011, and Durham on October 24, 2011. Notice of intervention was filed by the Attorney General on October 11, 2011.

[1] Duke Energy Carolinas is a wholly owned subsidiary of Duke Energy Corporation (Duke Energy).

[2] Duke Energy Business Services is an affiliate service company of Duke Energy Carolinas and a subsidiary of Duke Energy.

The Commission entered Orders granting the petitions to intervene of the Commercial Group on July 12, 2011, CUCA on July 20, 2011, CIGFUR III on July 12, 2011, NCSEA on August 23, 2011, NC WARN, et al., on September 20, 2011, Kroger on October 11, 2011, Time Warner on October 25, 2011, and Durham on October 27, 2011. The Commission denied the intervention of UMS on October 25, 2011. The Public Staff's intervention is recognized pursuant to G.S. 62-15(d) and Rule R1-19. The Attorney General's intervention is recognized pursuant to G.S. 62-20.

On July 28, 2011, the Commission issued its Order Scheduling Investigation and Hearing, Suspending Proposed Rates, Establishing Intervention and Testimony Dates and Discovery Deadlines, and Requiring Public Notice.

Duke Energy Carolinas filed supplemental direct testimony and exhibits for Company witnesses Shrum and McManeus on October 7, 2011, and filed the second supplemental direct testimony and exhibit of witness Shrum on October 14, 2011.

On October 31, 2011, Durham filed a Comment by counsel; NC WARN, et al., filed the direct testimony and exhibits of Gary Cook and Roger C. Colton; CIGFUR III filed the direct testimony and exhibits of Nicholas Phillips, Jr.; Time Warner filed the direct testimony of Brian W. Coughlan; Kroger filed the direct testimony and exhibits of Kevin C. Higgins; and the Commercial Group filed the direct testimony and exhibits of Steve Chriss and Wayne Rosa. On November 1, 2011, CUCA filed the direct testimony and exhibits of Kevin O'Donnell.

On November 1, 2011, the Public Staff filed the direct testimony and exhibits of Ben Johnson, Consulting Economist and President of Ben Johnson Associates, Inc.; Darlene Peedin, Supervisor of the Electric Section in the Accounting Division of the Public Staff; Karyl J. Crean, Supervisor of the Regulatory Analysis and Communications Section in the Accounting Division of the Public Staff; John R. Hinton, Director of the Economic Research Division of the Public Staff; Jack L. Floyd, Engineer in the Electric Division of the Public Staff; Howard M. Lowdermilk, Engineer in the Electric Division of the Public Staff; and Jay B. Lucas, Engineer in the Electric Division of the Public Staff.

On November 16, 2011, Duke Energy Carolinas filed the rebuttal testimony and exhibits of witnesses De May; Hevert; and Steven M. Fetter, President of Regulation UnFettered. On November 17, 2011, the Company filed the rebuttal testimony and exhibits of witnesses Bailey; Carter; Shrum; Jamil; Stillman; Kenneth Novak, an Executive Director with Ernst & Young, LLP; Keith G. Butler, Senior Vice President Tax for Duke Energy's affiliated companies; Mark A. Svrcek, Vice President of Wholesale Business and Renewables for Duke Energy; and Barbara G. Yarbrough, Rates Director for Duke Energy Carolinas.

On November 23, 2011, NC WARN, et al., filed a motion to allow response to Duke Energy Carolinas' rebuttal testimony. On November 28, 2011, Kroger filed a motion to substitute Neil Townsend for witness Higgins.

On November 28, 2011, Duke Energy Carolinas and the Public Staff entered into and filed an Agreement and Stipulation of Settlement resolving all issues between the two parties in this docket. On December 1, 2011, Duke Energy Carolinas and the Public Staff filed a corrected version of the Agreement and Stipulation of Settlement, which contained minor formatting changes and the addition of the word "consider" in Paragraph 5.E. On December 2, 2011, Duke Energy Carolinas, Time Warner, and the Public Staff filed an Amendment to Agreement and Stipulation of Settlement adding Time Warner as a party to the Stipulation and amending Paragraph 5.G. of the Stipulation to add a pilot energy rate within Rate Schedule SGS of 5.5 cents per kilowatt-hour (kWh) applicable to all energy consumed by cable television power supplies, plus the Basic Facilities Charge established in this proceeding. On January 4, 2012, Duke Energy Carolinas, Time Warner, and the Public Staff filed a Second Amendment to Agreement and Stipulation of Settlement, clarifying that the pilot rate for cable television power supplies would be an exception to the agreement that each component of each rate schedule was to be modified by an equal percentage.[1]

The public hearings were held as scheduled. The following public witnesses appeared and testified:

Charlotte: Bill Thunberg, Josh Crisp, Sally Kneidel, Ken Kneidel, Tommy George, Steve English, Mayolla Hernandez, Rogelio Reyes, Deb Arnason, Nancy Allison, Matt Wasson, Elizabeth Kincaid, Kayla Martinez, Yvonne McJetters, Jeff Edge, Heidi Martinez, June Blotnick, Harry Taylor, Lisa Zurkel, Garrett Hinshaw, Jack Kirven, Paul Nitsch, Barbara Conrad, Beth Henry, Darren Vincent, Susan Hunt, Pat Moore, Avram Friedman, Robbie Akhere, Aaron Woods, Paul Latten, Steven Navarro, Alissa Knuutila, Mark Johnson, Annie Vereen, Stephen Longstreet, Elijah Jackson, Lauren Bilski, Lea McLaughlin, Bill Gupton, Jennifer Marienau, Roxana Bendezu, Dianne Tyler, Todd Zimmer, Alan Burns, Monica Embrey, Grant Ehret, Rozlyn Cobb, Jason Dow, Megan Andrews, and John Moore

Marion: Richard Fireman, John Wilson, Sandra Diaz, Donna Edward, Lloyd Cuthbertson, Jan Hensley, Steve Little, Charles Jansen, Bob Boyette, Bryan Wilson, Ron Shuping, Carol Shaver, Andrew Tate, George Johnson, Kay Page, Suzanne Johnson, Elizabeth Lawly, Lee Dillingham, Katie Baird, John Hudson, William Pederson, Larry Grady, Sharon Bowman, Lew Patrie, Timothy Sadler, Amber Williams, James Duncan, Carl Manuel, Jack Keys, Deborah Haggins, Doug Taylor, Herman Langford, Roxanne Boyd, Phillip Bisesi, Stephen Holsenbeck, Don Stiver, Barry McPeters, Beth Henry, Randy Williams, and Josh Dobson

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[1] Hereinafter, the Agreement and Stipulation of Settlement, as corrected on December 1, 2011, and as amended on December 2, 2011, and January 4, 2012, shall be referred to as the "Stipulation" and the "Stipulating Parties" shall mean Duke Energy Carolinas, the Public Staff, and Time Warner. A copy of the Stipulation, as corrected on December 1, 2011, and the Amendments filed on December 2, 2011 and January 4, 2012, is attached hereto as Appendix A. The Settlement Exhibits are not included.

Franklin: Scott Burns, Cecil Bothwell, Bob Harold, Ronnie Beale, John Burton, Joan Maki, F.P. Bodenheimer, Jr., Carl Iobst, Hazle Finley, Narelle Kirkland, Susan Leveille, Roger Turner, Jack Fisher, Ken Brown, Bill Crawford, Joe Deddo, Bill Lyons, Karen Nye, Bettie Ashby, Adam Bigelow, Bob Kuppers, Gwen Taylor, Ray Nelson, Marie Galaz, Selma Sparks, Shirley Ches, James Burch, Gerard Bradley, Larry Stinger, William Thomas, Colleen Whittaker Shaw, Jean Welch, Connie Orr, and Natalie Warrick

High Point: Kay Hutchins-Self, David Allen, Donna Lisenby, Joey Edens, Rosa Daniels-Koonce, Sally Hirsh, Gary Green, David Wolfe, Larry Law, Bruce McCall, Jeff Deal, Harvey Pulliam, Jeff Miller, Margaret Able, Deidra Campbell, David Willett, Will Shuford, Nathan Roberto, William Heasley, Ernest Lankford, Valerie Warren, Todd Warren, Mike Inscore, Sam Stroud, Ghali Hasan, Dave Reed, Carissa Joines, John Kernodle, Maureen Kessler, Barbara Sonner, Rae Alton, Matthew Sheets, Jenny Barker, Kimberly Anderson, Jonathan Whitfield, Norma Marshall, Will Cox, Andrew Hobbs, William Bridge, Dianne Hobbs, Stephen Barnes, Sierra Dennis, Karen Neimczyk, and William Fletcher

Durham: Zell McGee, Jim Sander, Susan Concannon, Bob Gallagher, Marguerite Coyle, Gary Phillips, Gary Wallach, Laura Sandvik, Senator Eleanor Kinnaird, Jennifer Frye, Katherine Benson, Joan Novak, Hank Elkins, Mary MacDowell, Steve Toler, Carver Weaver, John Morris, Tony Garrett, Peter Childers, Mark Marcoplos, Fritzi Ross, Judy Schlegel, Harry Phillips, Cindy Soehner, Elizabeth Reeves, Judy Womack, Darius Little, Sonia Katchian, Heather Epes, Lloyd Schmeidler, Bert Gurganus, Imani Johnson, Bruce Mitchell, Fred Foster, Frank Ferrell, Peter Schubert, Wayne Spranger, Ruth Backstrom, Kevel Khalsa, Emily Wilkins, Jane Norton, and Josefina Slade

Raleigh: Miriam Thompson, Therese Vick, Valerie Warren, Rosalind McGee, Bettie Flash, Amina Turner, Glashia O'Rourke, Gene Nichol, Bob Rodriguez, Jon Haebig, Tony Caminiti, Phil Carson, David Monteith, Ruth Zalph, Emiley Joyce, Matthew Sheet, David Kahler, Thomas Henkel, Terrell Gleason, Nayely Perez-Huerta, Elizabeth Hutchby, Bill Wilson, Octavia Rainey, Heiderose Kober, and Roger Erlich

The matter came on for evidentiary hearing on November 29, 2011. Duke Energy Carolinas presented the testimony of witnesses Carter, Jamil, Svrcek, Stanley, Yarbrough, De May, Hevert, Fetter, Shrum, Stillman, and Bailey. The Public Staff presented the testimony of witnesses Hinton, Crean, Peedin, Johnson, Lucas, Lowdermilk, and Floyd. NC WARN, et al., presented the testimony of witnesses Cook and Colton. The pre-filed testimony of those witnesses who testified at the evidentiary hearing, as well as all other witnesses filing testimony in this docket, was copied into the record as if given orally from the stand.

On December 9, 2011, the Commission issued a notice of mailing of transcript and ordered that the parties submit briefs and/or proposed orders not later than January 9, 2012.

Based upon consideration of the pleadings, testimony, exhibits and Stipulation received into evidence at the hearings, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT AND CONCLUSIONS

Jurisdiction

1. Duke Energy Carolinas is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of this Commission. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in a broad area of central and western North Carolina. Duke Energy Carolinas is a wholly-owned subsidiary of Duke Energy, both having their offices and principal places of business in Charlotte, North Carolina.

2. The Commission has jurisdiction over the rates and charges, rate schedules, classifications, and practices of investor-owned public utilities operating in North Carolina, including Duke Energy Carolinas, under Chapter 62 of the General Statutes of North Carolina.

3. Duke Energy Carolinas is lawfully before the Commission based upon its Application for a general increase in its retail rates pursuant to G.S. 62-133 and 62-134 and Commission Rule R1-17.

4. The appropriate test period for use in this proceeding is the 12 months ended December 31, 2010, adjusted for increases in plant in service and construction work in progress (CWIP) for Cliffside Unit 6[1] through September 2011, and other fixed, known, and measurable changes.

The Application

5. Duke Energy Carolinas, by its Application and initial direct testimony and exhibits, originally sought an increase of $646,057,000, or 15.2%,[2] in its annual electric sales revenues from its North Carolina retail electric operations, including a rate of return on common equity (ROE) of 11.5%. On October 7 and October 14, 2011, respectively, the Company filed supplemental direct testimony and exhibits and second supplemental direct testimony and exhibits, updating its Application and its requested base rate increase, resulting in an updated requested increase in its

[1] However, the CWIP for Cliffside Unit 6 above the amount approved in Docket No. E-7, Sub 909 was not included in rate base under the terms of the Stipulation.

[2] As indicated on the Notice of Public Hearings attached to the July 28, 2011 Order Scheduling Investigation and Hearing, Suspending Proposed Rates, Establishing Intervention and Testimony Dates and Discovery Guidelines, and Requiring Public Notice, the requested increase of $646,057,000, or 15.2%, reflects riders and charges approved by the Commission in other dockets, as well as weather normalization and other adjustments filed in the general rate case.

annual North Carolina retail revenues of $637,969,000. The Public Staff filed testimony and exhibits in this docket on November 1, 2011, recommending a number of adjustments to the Company's requested revenue requirement. The Company filed rebuttal testimony on November 16 and 17, 2011, accepting or choosing not to contest certain of the Public Staff's adjustments and reducing the requested ROE to 11.25%, resulting in an updated requested increase in the Company's annual North Carolina retail revenues of $525,003,000.

6. Duke Energy Carolinas submitted evidence in this case with respect to revenues, expenses, and rate base using a test period consisting of the 12 months ended December 31, 2010, adjusted for certain known changes in revenues, expenses, and rate base.

The Stipulation

7. On November 28, 2011, Duke Energy Carolinas and the Public Staff entered into and filed an Agreement and Stipulation of Settlement (a corrected version of which was filed on December 1, 2011) resolving all issues in this proceeding between the two parties. The Stipulation is based upon the same test period used by the Company in the Application. On December 2, 2011, Duke Energy Carolinas, Time Warner, and the Public Staff filed an Amendment to Agreement and Stipulation of Settlement adding Time Warner as a Stipulating Party and comprehensively resolving all issues in this proceeding among the Stipulating Parties. On January 4, 2012, the Stipulating Parties filed a Second Amendment to Agreement and Stipulation of Settlement for purposes of clarification.

8. The Commission, having carefully reviewed the Stipulation and all of the evidence of record, finds and concludes that the provisions of the Stipulation are just and reasonable to all parties under the circumstances of this proceeding and should be approved, except for Paragraph 5.E. and modifications to Paragraph 9.F., as discussed herein. The specific terms of the Stipulation and exceptions thereto are addressed in the following findings of fact and conclusions.

9. The Stipulation provides for a net increase of $309,033,000 with respect to Duke Energy Carolinas' annual North Carolina retail electric operating revenues, based upon the Company's adjusted test-period level of operations. The Stipulating Parties agree that these revenues are intended to provide Duke Energy Carolinas, through sound management, the opportunity to earn an overall rate of return of 8.11%. This overall rate of return is based upon a capital structure consisting of 47% long-term debt and 53% common equity, Duke Energy Carolinas' long-term debt cost rate of 5.41%, and an ROE of 10.5%.

10. The Commission has reviewed the Stipulation's provisions for an annual electric sales revenue increase of $309,033,000 and finds and concludes that this increase in the level of base rates to be paid by Duke Energy Carolinas' North Carolina retail customers is just and reasonable to all parties in consideration of all the evidence presented. The Commission finds and concludes that the following amounts of operating revenues, operating revenue deductions, and original cost rate base (under present rates) are appropriate and reasonable for purposes of setting rates in this proceeding: $4,409,946,000 of operating revenues; $3,726,277,000 of operating revenue deductions; and $10,673,442,000 of original cost rate base.

11. The Stipulation provides for certain accounting adjustments that are set forth in detail in Settlement Exhibit 1 to the Stipulation. The Stipulating Parties agree that settlement on these issues will not be used as a rationale for future arguments on contested issues brought before the Commission. The Commission finds and concludes for the present case that the accounting adjustments outlined in Settlement Exhibit 1 to the Stipulation are just and reasonable to all parties in consideration of all the evidence presented.

12. In consideration of settlement, the Company waives its right to increase the amount of CWIP in rate base for any expenditure associated with Cliffside Unit 6 above the North Carolina retail portion of the $1,023,521,000 system amount included in the Company's rate base in Docket No. E-7, Sub 909. Instead, the Company will continue to capitalize allowance for funds used during construction (AFUDC) on all expenditures associated with Cliffside Unit 6 not included in rate base as a result of the Commission's Order in Docket E-7, Sub 909. The Commission finds and concludes that this provision of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

13. In consideration of settlement, and to achieve the recommended rate increase, the Stipulating Parties agree that the Company as part of this proceeding will flow through to customers over one year the North Carolina retail allocated share of its September 30, 2011, balance of accumulated Environmental Protection Agency (EPA) sulfur dioxide auction proceeds, which have been maintained to date as a regulatory liability on the Company's books and records. The Commission finds and concludes that the flow through of EPA auction proceeds to customers is just and reasonable to all parties in light of all the evidence presented.

14. Duke Energy Carolinas based its filing in this case on the Summer Coincident Peak (SCP) methodology for allocation of the cost of service among jurisdictions and among customer classes. The Public Staff advocates the use of the Summer-Winter Peak and Average (SWPA) methodology for those purposes. The Stipulation provides that the SCP methodology for allocation among jurisdictions and among customer classes shall be used in this case and shall not be a precedent for and may be contested in future general rate case proceedings, and that the Company will continue to file annual cost of service studies based on both the SCP and SWPA methodologies. The Company also agrees that it will not cite Commission approval of the Stipulation as support for approval of use of the SCP methodology in future proceedings. The Commission finds and concludes that for purposes of this proceeding the Company may continue to use the SCP methodology for allocation among jurisdictions and among customer classes under the provisions of the Stipulation and that this methodology is just and reasonable to all parties in light of all the evidence presented.

15. The Stipulation provides for a base fuel and fuel-related cost factor of 2.3935 cents per kWh, excluding gross receipts tax and regulatory fee, which the Commission finds and concludes is just and reasonable to all parties in light of all the evidence presented. The differentials between the composite base fuel and fuel-related cost factors and total fuel and fuel-related cost factors by customer class shall be included in the rider components of Duke Energy Carolinas' Fuel Cost Adjustment Rider (NC), and shall be subject to modification in the Company's annual fuel charge proceedings.

16. The Stipulation provides that the expiring demand-side management (DSM) deferral account balance rider of 0.0140 cents per kWh, excluding gross receipts tax and regulatory fee, scheduled to expire December 31, 2012, shall remain in effect until the expiration date, as previously approved in Docket No. E-7, Sub 828 and reaffirmed in Docket No. E-7, Sub 909. The Commission finds and concludes that this provision of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

17. The Stipulation provides that the base rates approved in this proceeding shall be considered to include: (a) an increment amount for use in the annual proceeding to adjust the Existing DSM Program Rider (EDPR), as approved in Docket No. E-7, Sub 828, and reaffirmed in Docket No. E-7, Sub 909; and (b) decrement amounts of 0.0642 cents per kWh and 0.0067 cents per kWh (both excluding gross receipts tax and regulatory fee), for flowback of, respectively, Bulk Power Marketing (BPM) Net Revenues and Non-Firm Point-to-Point Transmission Revenues, for purposes of measuring the continuing annual adjustment to the BPM True-Up Rider as previously approved in Docket No. E-7, Sub 828, and reaffirmed in Docket No. E-7, Sub 909. The Commission finds and concludes that this provision of the Stipulation is just and reasonable to all parties in light of all the evidence presented and orders that the increment amount related to the EDPR be provided at the time the Company makes its compliance filing in this docket.

18. The Stipulation provides that Duke Energy Carolinas' rates resulting from this proceeding will be designed such that no customer class shall receive a net total cumulative increase stated on an annual basis of more than 7.21%. The Commission finds and concludes that this provision of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

19. The Stipulation provides for certain changes in Duke Energy Carolinas' rate design which are set out in detail in Paragraph 5 of the Stipulation. The Commission finds and concludes that the changes to rate design as described in the Stipulation are just and reasonable, with the exception of Paragraph 5.E. with regard to OPT rates.

20. The Commission finds and concludes that it is appropriate that the Company reduce the rate differential between rates OPT-I/OPT-H and OPT-G by one-third as part of this proceeding.

21. The Commission finds and concludes that within 90 days from the date of this Order the Company and the Public Staff should invite representatives from the City of Durham, and other interested Duke Energy Carolinas' municipal customers, to meet regarding the fairness of the rates in Schedule GL and the Company's procedures for detection, reporting and repair of malfunctioning street lighting in an attempt to resolve these issues, if possible, before the Company's next general rate case proceeding.

22. Consistent with Paragraph 8 of the Stipulation, the Commission finds and concludes that the overall quality of electric service provided by Duke Energy Carolinas is good.

23. The Stipulation provides that the Company will make a one-time $11,000,000 shareholder contribution to agencies that provide energy assistance to low-income customers for uses such as those identified in Docket No. E-7, Sub 795. The Company will consult with the Public Staff and submit a proposal to the Commission within 60 days of this Order and such funds will be paid from shareholders to the appropriate agencies by July 1, 2012. These funds are to be used exclusively to provide energy assistance to the North Carolina retail customers of Duke Energy Carolinas. The Commission finds and concludes that this provision of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

24. The Company filed its Coastal Wind Demonstration Project Rider as a matter of administrative convenience in this docket. The Stipulating Parties agree that the amount to be recovered through this Rider will be based on Duke Energy Carolinas' calculation of costs incurred through the end of March 2010 ($1,191,696, plus a return at the weighted average cost of capital approved in this Order, totaling $1,396,232). The Commission finds and concludes that the amount to be recovered through the Coastal Wind Demonstration Project Rider pursuant to the Stipulation is just and reasonable to all parties in light of all the evidence presented. This rider shall be in effect for a 12-month period beginning the effective date of the base rates approved in this Order.

25. The Company agrees to the review of its vegetation management policy and procedures and filing of same with the Commission, as recommended by Public Staff witness Lowdermilk. Accordingly, within 90 days of the date of this Order, the Company will review its vegetation management policies and procedures, develop a clear, comprehensive, consistent, and publicly-available policy description and file it with the Commission for review in a separate docket.

26. The Stipulating Parties agree to the positions set out in the pre-filed rebuttal testimony of Company witness Shrum regarding possible accounting changes for the generating mix of the Buck Combined Cycle Facility (Buck) and the Bridgewater Hydroelectric Facility (Bridgewater). In the Stipulation, as set forth in Paragraph 9.B., the Public Staff reserves the right to challenge any deferral application the Company files to recover costs for new plant at the Buck and Bridgewater facilities.

27. The Company will review outside services for the 2011 calendar year to investigate whether any costs have been improperly charged to North Carolina retail operations, and will propose safeguards to prevent the charging of outside services to accounts other than Account 923, per recommendation of Public Staff witness Peedin and agreement by Company witness Shrum. Duke Energy Carolinas shall file a verified report describing the results of its review and its proposed safeguards by July 1, 2012, as agreed to in the Stipulation, at Paragraph 9.E.

28. As to the stopped meter issue raised by Public Staff witness Lowdermilk, the Company agrees to send a letter to all customers after four months of no usage, except for customers on Schedules SGS and LGS utilizing the annual minimum billing options and customers that the Company has identified as seasonal customers. The Company will work with the Public Staff as to the content of the letter. The Company will implement this procedure within 120 days of the date of this Order and report to the Public Staff and Commission upon

implementation. The Company will meet with the Public Staff within six months of implementation and file a formal report with the Commission within a year after implementation that contains the following: (1) the number of stopped meter customer letters mailed, (2) the number of customer responses received, (3) the number of stopped meters discovered as a result of the customer contact, (4) the number of months back billed for each stopped meter discovered, and (5) the amount of the back billing for each meter.

29. By the filing date of its next general rate case, the Company will provide the Public Staff with (1) a detailed reconciliation of the per books amounts in its accounting records to the Cost of Service Study, showing which accounts and amounts are included in each line item of the Cost of Service Study, and (2) all work papers supporting any allocations not shown in the filed Cost of Service Study, as agreed to in the Stipulation, at Paragraph 9.H.

30. At the time of its annual filings of all future North Carolina Supplemental Financial Reports provided with the Duke Energy Carolinas' Federal Energy Regulatory Commission (FERC) Form 1, the Company will provide the Public Staff with a list of all outside services charged to Duke Energy Carolinas not included in the North Carolina Supplemental Financial Reports information, whether obtained directly or through a service company, as agreed to in the Stipulation, at Paragraph 9.I.

Additional Findings and Conclusions

31. The Company incurs costs from its collection activities and it recovers a portion of those costs through its 1% late payment charge pursuant to Commission Rule R12-9. NC WARN, et al., has not met its burden to prove that the Company's late fee charges and practices are illegal or unreasonable. Therefore, the Commission declines to accept NC WARN, et al., witness Colton's recommendations regarding the Company's late fees in this proceeding. His recommendations are inconsistent with Commission Rule R12-9 in that they would apply to Duke Energy Carolinas alone instead of all public utilities, would carve out an exception to the rule for low-income customers where none currently exists, and would create a new late payment charge based on factors not referenced by Commission Rule R12. The Commission finds and concludes that the Company's late fees are just and reasonable and in accordance with Commission rules.

32. NC WARN, et al., has not met its burden to prove that the Company's disconnection notices or policies are illegal or unreasonable. Therefore, the Commission declines to accept NC WARN, et al., witness Colton's recommendations with respect to Duke Energy Carolinas' disconnection notices and policies. The Commission finds and concludes that the Company's disconnection notices and policies are in compliance with Commission rules and are not unfair or deceptive.

33. Several public witnesses expressed concerns regarding the quality of service being provided to their premises by Duke Energy Carolinas. The Commission finds and concludes that these situations warrant further investigation by the Company and review by the Commission. Therefore, Duke Energy Carolinas should be required to investigate and attempt to resolve these customers' concerns and file detailed reports of its actions with the Commission.

EVIDENCE SUPPORTING FINDINGS OF FACT AND CONCLUSIONS NOS. 1-4

The evidence supporting these findings of fact and conclusions is contained in the verified Application and Rate Case Information Report – Electric Companies (Form E-1) of Duke Energy Carolinas, the testimony and exhibits of the witnesses, and the entire record in this proceeding. These findings and conclusions are informational, procedural, and jurisdictional in nature, and are not contested by any party.

EVIDENCE SUPPORTING FINDINGS OF FACT AND CONCLUSIONS NOS. 5-8

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, Duke Energy Carolinas' verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

On July 1, 2011, Duke Energy Carolinas filed its application and initial direct testimony and exhibits, seeking an increase of $646,057,000 or 15.2% in its annual electric sales revenues from its North Carolina retail electric operations. On October 7, 2011, the Company filed supplemental direct testimony and exhibits updating its cost of service and filed second supplemental direct testimony and exhibits further updating its cost of service on October 14, 2011. The Company filed rebuttal testimony on November 16 and 17, 2011, further updating its cost of service by accepting or choosing not to contest a number of adjustments recommended by the Public Staff. On November 28, 2011, the Company and Public Staff filed the Stipulation, comprehensively resolving all issues in this proceeding between themselves. On December 1, 2011, the Public Staff filed a correction to the Stipulation, with which the Company agreed. On December 2, 2011, Duke Energy Carolinas, Time Warner, and the Public Staff filed an Amendment to Agreement and Stipulation of Settlement adding Time Warner as a Stipulating Party. Further, on January 4, 2012, the Stipulating Parties filed a second amendment to the Stipulation.

The Stipulation provides for a net increase of $309,033,000 or 7.21% in Duke Energy Carolinas' annual revenues from kWh sales from its North Carolina retail electric operations. Duke Energy Carolinas submitted evidence in this case with respect to revenues, expenses, and rate base using a test period consisting of the 12 months ended December 31, 2010, updated for certain known and actual changes. The Stipulation is based upon the same test period.

Need for Rate Increase

Company witness Carter provided testimony explaining the Company's reasons for seeking a rate increase at this time. He testified that this case is driven by the $4.8 billion of capital invested in the "bricks and mortar" projects of the Company, including its modernization program that consists of retiring, replacing, and upgrading generation plants and transmission and distribution systems. Witness Carter explained that the need for the requested rate increase is largely due to continuation of the modernization strategy that underpinned the Company's last rate case (Docket No. E-7, Sub 909), and that, like many utilities, the Company is taking steps to replace aging power plants, the average age of which is 40 years old across the United States. The approximate average ages of Duke Energy Carolinas' coal and hydroelectric plants are 61 and 79 years, respectively, and the average age of the Company's nuclear fleet is 30 years. Witness Carter also testified that Duke Energy Carolinas' modernization strategy included modernizing the Company's transmission and distribution systems, of which major components range in age between 30 and 40 years. He explained that the Company's need to modernize its system is driven by ever-increasing environmental compliance requirements, such as the need for emission controls to comply with increasingly stringent state and federal emission regulations. Witness Carter stated that the Company's modernization program is necessary to enable it to continue to safely provide reliable and environmentally compliant electricity at reasonable costs for Duke Energy Carolinas' customers.

Witness Carter observed that the capital investments for which the Company seeks recovery include the following major projects or categories: (1) Cliffside Unit 5 Scrubber ($565 million); (2) Cliffside Unit 6 (financing costs associated with $641 million additional investment); (3) Tornado/High Energy Line Break work at Oconee Nuclear Station ($135 million); (4) Buck Combined Cycle Project ($700 million); (5) Bridgewater Powerhouse Replacement Project ($180 million); (6) Transmission and Distribution (approximately $1.0 billion); and (7) Nuclear Fuel ($207 million).

Further, witness Carter stated that the Company has also spent approximately $1.4 billion on hundreds of other capital maintenance, generation, and general projects. These projects were explained in the testimony of Company witnesses Jamil and Stanley.

Witness Jamil testified that the Company has made significant investments for capital additions since the Company's 2009 rate case within its nuclear, fossil/hydro, and renewable generation fleets. He explained that these capital additions are part of the Company's efforts to add new generation assets, maintain reliability, modernize existing assets for greater efficiency and to address obsolescence, continue with life extension efforts of nuclear units, and carry on with relicensing ventures, as well as to comply with new or updated regulatory requirements.

Witness Jamil testified about several capital projects at the Company's nuclear sites. In particular, at the Catawba Nuclear Station, the Company has replaced and upgraded a service water system and installed digital process systems (DCS) in the control room. DCS and an upgraded fire detection system were also installed at the McGuire Nuclear Station. In addition, at the Oconee Nuclear Station, preparations were made for the installation of a new safety-related digital reactor protection system, as well as multiple equipment and system upgrades to the facility. Updated security measures and a safety-related protected service water system were also implemented at Oconee, in compliance with regulatory requirements.

Further, witness Jamil testified about the major capital projects for the Company's fossil/hydro and renewable fleets. He observed that investments to the Company's coal-fired fleet included (1) installation of Flue Gas Desulfurization (FGD) equipment (scrubber) at Cliffside Unit 5; (2) coal blending expansion at Marshall; (3) upgrades at Belews Creek; and (4) dry ash conversion at Allen. The Company also added a combined cycle combustion turbine at the Buck Steam Station site, which provides an additional 620 megawatts (MW) of generation. Witness Jamil testified that the Company made investments in its hydro fleet as well, including construction of a new powerhouse downstream of the Bridgewater Hydro Station near Morganton, North Carolina. He observed that the new powerhouse will increase generation by

8.5 MW and add dissolved oxygen to improve the downstream aquatic habitat. In addition, Units 1 and 2 at Jocassee Hydro Station were upgraded, resulting in 50 MW of increased generation and an additional 75 MW of pumping capability. In accordance with the FERC's initiative to increase the safety of dams during severe earthquakes, the Company has also made repairs to existing intake structures in its hydro fleet as well as improvements to the three dams that form Lake James. The Company also made investments in renewable generation, completing solar photovoltaic distributed generation projects at eighteen commercial sites and seven residential sites for a total of approximately 10 MW.

Company witness Stanley testified about the Company's capital improvements to its transmission and distribution (T&D) systems. He testified that the Company's Power Delivery systems are upgraded on an ongoing basis through a variety of programs and projects. He explained that through its inspection and maintenance programs the Company regularly identifies system components that require replacement or refurbishment, including poles, transformers, circuit breakers, and conductors. According to witness Stanley, from the time of conclusion of the Company's 2009 rate case through the conclusion of this rate case, the Company will have added approximately $843 million for distribution and $255 million for transmission to electric plant in service. The Company dedicated approximately 18% of its annual T&D capital expenditures in 2009 and 2010 to making reliability improvements to its system. Witness Stanley testified that the Company has many proactive programs for continuous improvement in reliability, including sectionalization[1]; distribution automation; substation control relays; substation animal fences; transmission line equipment; declared circuits; fuse replacements; deteriorated conductor replacements; distribution line infrared circuit backbones; and transformer retrofits. In addition to making strategic investments that were targeted at reliability, the Company also dedicated approximately 17% of its annual T&D capital expenditures in 2009 and 2010 to planned and unplanned infrastructure maintenance activities, including repairing and replacing system components that were nearing the end of their life; replacing capital units of property during routine outage events; relocating lines to accommodate highway projects; and carrying out various compliance activities.

Company witness Carter explained that most of the increase sought was for costs related to the capital projects undertaken by the Company, but that the Company also sought recovery for increases of $28 million in employee benefits and $23 million annually, for the next three years, for costs attributable to the Company's Voluntary Opportunity Program (VOP), which provided the Company a means to reduce labor and labor-related costs through voluntary severance. The Company included the lower headcounts resulting from the VOP when it calculated its labor expense in this case.

Company witness Jamil explained the Company's cost containment efforts. He testified that the Company controls costs for capital projects and operations and maintenance (O&M) utilizing a rigorous cost management program. Witness Jamil stated that costs are sustainably controlled through routine executive oversight of project budget and activity reporting with new projects requiring approval by progressively higher levels of management depending on total project costs. Ongoing project and O&M costs are controlled through strategic planning and

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[1] This involves the installation of automatic devices to limit the number of customers impacted by individual outage events.

procurement; efficient execution or oversight of contractors by a trained and experienced workforce; rigorous monitoring of work quality; thorough critiques to reveal process improvement; and industry benchmarking to ensure best practices are being utilized.

The Company also focuses on cost-effective operation. In 2010, the Company's nuclear fleet had the lowest total operating cost for the industry, as compared to all other United States nuclear fleet operators, based on Electric Utility Cost Group cost and performance results. The Company's 2010 average total operating cost for its nuclear fleet, which includes operating and maintenance, administration, and fuel costs, was $19.61/megawatt-hour. Witness Jamil explained how the Company's fossil/hydro Generation Excellence Program provides each station with a structured process for identifying, evaluating, sharing, and implementing cost-saving and process improvement ideas. Additionally, witness Jamil described various strategies employed by the Company to manage increasing fuel costs, including staggering its contracts for nuclear fuel and coal in order to limit its exposure to price volatility.

Witness Carter explained that as a result of these efforts the Company has kept core operation and maintenance expenses essentially flat since rates were last established and that the Company is still performing well. Furthermore, witness Carter observed that the Company's modernization program has not concluded and that the Company plans to spend $7.0 billion in capital expenditures that include costs for the Cliffside Unit 6 project and for new gas-fired generation projects, in addition to ongoing environmental and Nuclear Regulatory Commission compliance costs and numerous other capital projects. Additionally, witness Carter opined that the Company, like many other utilities, is facing challenges such as the cost uncertainties associated with rising health care costs, compliance costs for North American Electric Reliability Corporation (NERC) requirements, cyber security concerns, and other pressures. Both witness Carter and Company witness De May testified that the Company must remain attractive to the financial community in order to access the capital it needs on reasonable terms for the benefit of the Company's customers.

As a result of its investigation into the Company's application, the Public Staff filed testimony recommending an increase of $211,119,000, with much of its proposed reduction from the Company's request due to Public Staff witness Johnson's recommendations regarding the cost of capital. The Public Staff did not contest the reasonableness or prudence of the capital investments made by the Company for plant modernization.

<u>The Stipulation</u>

Witness Carter testified that the Company worked diligently to reach a compromise with the Public Staff in this case, which he believes strikes a balance between today's challenging economic times and the need to recover the investments the Company has made in its electric system. He then described the four main provisions of the Stipulation.

First, pursuant to the Stipulation, the Company's rates would increase 7.2%[1] across-the-board for all customer classes. He explained that the Stipulating Parties ultimately got to this number by extensive give-and-take negotiations between the Company and the Public Staff on

[1] This is a rounded number, as Settlement Exhibit 2 and other testimony indicate a 7.21% increase.

various line items discussed in the testimony of Public Staff witness Peedin and the rebuttal testimony of Company witness Shrum. The stipulated 7.2% increase is less than half of the increase Duke Energy Carolinas originally requested.

Second, under the Stipulation, the Company would waive its statutory right to increase the present amount of Cliffside Unit 6 CWIP in rate base and defer collection of the associated \$51 million in revenue requirement. Witness Carter cited this provision of the Stipulation as an example of how, by settling with Public Staff, the Company was able to come up with some solutions not readily available in a fully litigated case.

Third, the Stipulation provides the Company with an opportunity to earn an ROE of 10.5%. Witness Carter explained that while Company witness Hevert recommended an ROE of 11.25%, in light of the entire Stipulation and in consideration of the difficult times customers are facing in North Carolina, the Company is willing to accept a 10.5% ROE.

Finally, witness Carter testified that the Company realizes that its low-income customers in particular are having a hard time managing through these difficult economic times. Accordingly, Duke Energy Carolinas agrees in the Stipulation to contribute \$11 million of shareholder funds for assistance to low-income residential customers in North Carolina.

The Stipulation also provides for a number of time extensions for amortization and depreciation expenses, relative to the Company's position in pre-filed testimony. The extensions mitigate the rate impact to customers, according to witness Carter. He explained that the Stipulation is a compromise which reflects the Company's effort to respond to its customers' concerns and to maintain Duke Energy Carolinas' strong balance sheet and access to capital.

Company witness Shrum testified that Settlement Exhibit 1 shows the Company's original requested increase, provides detail on the adjustments made by the Public Staff, and shows the Company's acceptance, for the purposes of settlement, of most of those adjustments in whole or in part. The resolution of those adjustments as a result of the compromise between the Company and Public Staff brings the Company's total increase request of \$646 million of required revenue down to \$309 million. Witness Shrum explained that many of the adjustments not contested by the Company are described in her rebuttal testimony and that the remaining adjustments were resolved by negotiations and a desire to mitigate customer rate impacts.

Company witness Yarbrough testified that the Stipulation includes provisions outlining the Stipulating Parties' agreement with respect to the Company's response to stopped meters and the Company's vegetation management policy. With respect to stopped meters, the Company agrees to send a letter to all customers after four months of no usage, except customers that are utilizing the annual minimum billing options and customers the Company identifies as seasonal. Once this new procedure is implemented, the Company will meet with the Public Staff within six months and file a formal report within a year of implementation containing the following: the number of stopped meter customer letters mailed, the number of customer responses received, the number of stopped meters discovered as a result of the customer contact, the number of months back billed for each stopped meter discovered, and the amount of the back billing for each meter.

With respect to the Company's vegetation management policies, Duke Energy Carolinas has agreed that, within 90 days of the Commission's Order in this matter, the Company will review its vegetation management policies and procedures, develop a clear, comprehensive, consistent, and publicly-available policy description, file it with the Commission, and publish it on its website in a publicly available manner. The Stipulating Parties agree to further discussions to effectuate these commitments.

Company witness Bailey explained that for the purposes of settlement, the Company and the Public Staff agreed to various rate design changes to effectuate the recommended 7.21% increase to all rate classes. He testified that he believes that the agreed-upon provisions represent a reasonable compromise of the issues in the context of the settlement. In summary, the rate design provisions of the Stipulation are as follows:

- Each rate component for each rate, including the Basic Facility Charges, shall be modified by an equal percentage to arrive at the average increase depicted in Settlement Exhibit 2. An exception is allowed for cable television power supplies.

- The Extra Facilities Rate shall be adjusted prospectively consistent with the cost of capital and capital structure described in Paragraph 2.A. of the Stipulation and associated income tax effects. The Company and the Public Staff have agreed to further discussions to effectuate this commitment.

- The wording of Schedule HP shall be revised as recommended in Lowdermilk Exhibit 2. Other changes to Rate HP recommended by witness Bailey are agreed upon by the Public Staff and the Company.

- The Public Staff and the Company agree to the implementation of a Transformation Discount Pilot with various reporting requirements as outlined in Paragraph 5.D.

- Rate Schedules OPT-G and OPT-I shall not be consolidated at this time. The Company and the Public Staff agree to consider a three step phase-in of the consolidation to be presented in the Company's next general rate proceeding.

- The Company will develop a plan to transition customers served on Rate Schedules YL and FL-N to Rate Schedules OL and FL, respectively, and to present the transition plan in the Company's next general rate case.

- The Stipulating Parties agree that further investigation is needed to develop a proposal for low use, high load factor non-residential loads, including cable television power supplies, and agree to work together with the intent that the Company will file such a proposal in its next rate case. This provision was amended as discussed in the next paragraph.

- The Stipulating Parties recognize that as a result of changes to rate schedules, it is anticipated that customers will migrate to different rate schedules. The Stipulation provides that in the development of final rates, Duke Energy Carolinas shall calculate the expected lost revenue due to migrations and recover 50% of this amount from the classes of customers in which migration occurs. Duke Energy Carolinas shall provide the Public Staff with a copy of the calculations and supporting data on or before December 16, 2011. The Public Staff retains the right to contest the reasonableness of the adjustment that the Company proposes to incorporate for expected lost revenue due to migrations and to request an evidentiary hearing for the purpose of resolving any such dispute.[1]

- The Stipulating Parties agree to continue to investigate how rate design can effectively and fairly promote greater energy efficiency.

- The Stipulating Parties agree to continue to investigate the feasibility of dynamic pricing rate structures, including but not limited to critical peak pricing and time-of-use rate structures for both residential and non-residential customers, with the intent to include such dynamic pricing rate structures as a pilot program in the Company's next general rate case proceeding.

After the close of the evidentiary hearing, Time Warner joined as a Stipulating Party and Paragraph 5.G. of the Stipulation was amended to state:

> The Stipulating Parties agree that Duke Energy Carolinas shall create a provision within Rate Schedule SGS for cable television power supplies as a pilot to be in effect until new rates go into effect as a result of the Company's next general rate case. The provision will provide for an energy rate of 5.5 cents/kWh applicable to all energy consumed by cable television power supplies, plus the basic facilities charges established for Rate Schedule SGS in this proceeding. Information from the pilot period will be used to study the cost justification and feasibility of an appropriate on-going provision for all low use, high load factor non-residential loads, including cable television power supplies. Such information will be the basis for a recommendation to be included in the next general rate case application of Duke Energy Carolinas, and the Stipulating Parties may provide updated information, if appropriate, as the study continues through the close of hearing. The Company will share the results of its study with interested parties, with the intent that an on-going provision or separate rate for low use, high load factor non-residential customers may be proposed in the next general rate case following completion of the study.

The Commission finds and concludes that the Stipulation appropriately balances the Company's need for rate relief with the impact of such rate relief on customers. The Commission is very cognizant of the fact that many people continue to suffer from the effects of the recession and that a rate increase will be difficult for customers to absorb. At the same time, the Company has made and continues to make substantial investments in order to comply with regulatory

[1] In the Joint Proposed Order of Duke Energy Carolinas and the Public Staff, filed January 9, 2012, the Public Staff indicated it had received and was satisfied with the calculations and supporting data provided by Duke Energy Carolinas. Accordingly, this part of the Stipulation has been fulfilled.

requirements and provide reliable electric utility service to its customers, and under North Carolina law the Company has the right to an adjustment of its rates to reflect the reasonable cost of these investments. In particular, the overall revenue requirement, which is substantially lower than that requested in the Company's Application, along with the Company's agreement to contribute $11 million for low-income energy assistance and the waiver of its right to increase the amount of CWIP in rate base, will mitigate the impact of the rate increase on customers. The Commission concludes that the Stipulation, with the exception of Paragraph 5.E. and modifications to Paragraph 9.F., represents a just and reasonable resolution of the issues for all parties in this proceeding and therefore is in the public interest.

As the Stipulation has not been adopted by all of the parties to this docket, its acceptance by the Commission is governed by the standards set out by the North Carolina Supreme Court in State ex rel. Utilities Comm'n v. Carolina Utility Customers Ass'n, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998) (CUCA I) and State ex rel. Utilities Comm'n v. Carolina Utility Customers Ass'n, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000) (CUCA II). In CUCA I, the Supreme Court held 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 not all of the parties have entered into a settlement did 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." 351 N.C. at 231-32, 524 S.E.2d at 17.

There is sufficient evidence in the record to support all of the provisions of the Stipulation, with the exceptions discussed herein, including those which have been contested by some intervenors other than the Stipulating Parties. Accordingly, the Commission is justified in finding and concluding through the exercise of its own independent judgment that the Stipulation "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. The Commission therefore adopts the Stipulation , with the exceptions discussed herein, and sets forth its conclusions as to the individual provisions of the Stipulation more fully below.

EVIDENCE SUPPORTING FINDINGS OF FACT AND CONCLUSIONS NOS. 9-11

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, Duke Energy Carolinas' verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

The Stipulation provides for a net increase of $309,033,000 with respect to Duke Energy Carolinas' annual jurisdictional revenues, based upon the adjusted test-period level of operations. To achieve this increase, Duke Energy Carolinas will adjust its North Carolina retail base rates to produce annual sales revenues of $4,718,979,000. The Stipulating Parties agree that these revenues are intended to provide Duke Energy Carolinas, through sound management, the opportunity to earn an overall rate of return of 8.11% on a jurisdictional rate base of $10,673,442,000. Such overall rate of return is based upon a capital structure consisting of 47% long-term debt and 53% common equity, Duke Energy Carolinas' long-term debt cost rate of 5.41%, and an ROE of 10.5%.

Capital Structure

Duke Energy Carolinas originally proposed, and the Stipulation provides for, a capital structure of 47% long-term debt and 53% common equity

Company witness De May addressed Duke Energy Carolinas' credit quality, capital structure, and cost of capital, and the importance that each of these has in supporting the Company's current "A-level" credit ratings and financial objectives. He explained that strong credit ratings, such as those held by Duke Energy Carolinas today, result from a favorable assessment by the credit rating agencies and debt investors of the Company's financial strength, including its ability to raise capital, meet its future financial obligations, and withstand changes in its business environment.

Witness De May testified that Duke Energy Carolinas relies on third-party capital in order to make the significant investments required to build, maintain, and operate the infrastructure necessary to deliver cost effective and reliable electric service to its customers. According to witness De May, strong credit ratings and a fair and reasonable return to the Company's equity investors are vitally important factors that contribute to the Company's ability to attract capital on reasonable terms. He explained that the rating agencies consider many factors in assessing the credit quality of a utility company like Duke Energy Carolinas, but foremost among them are the adequacy of certain financial measures and the constructiveness of the regulatory jurisdictions within which the company operates. Witness De May testified that, according to the rating agencies' most recent reports, the Company's financial measures are generally within their A-category guidelines, and both agencies consider the North Carolina regulatory jurisdiction as being supportive of credit quality.

Witness De May further testified that approval of the proposed capital structure comprised of 47% debt and 53% equity would support the Company's financial objectives by providing sufficient cash flows to maintain its necessary capital expenditure program and service debt. Witness De May explained that the greater the equity component of capitalization, the safer the returns are to debt investors, which translates into higher credit quality. According to witness De May, high credit quality creates financial flexibility by providing greater assurance of access to the capital markets on reasonable terms, and ultimately lower debt financing costs. During the evidentiary hearing, witness De May explained that the introduction of more debt and less equity into the capital structure is contrary to maintaining the current level of creditworthiness of Duke Energy Carolinas.

Upon questioning by the Attorney General, Company witnesses Hevert, Fetter, and De May provided testimony as to the effect a downgrade of Duke Energy Carolinas' credit rating would have on the Company's ability to obtain access to capital on reasonable terms. Witness Hevert testified that as markets become "constrained and volatile … the higher credit ratings are what enable access to the capital in … the more difficult market environment at, of course, reasonable terms." Similarly, Witness De May testified that

> The question though then becomes is it necessary to have an A minus rating versus a BBB level rating …. I'm here to tell you that I don't think being investment grade is good enough anymore and I think the financial crisis of 2008/2009 taught me as treasurer of the Company a couple of things: Credit ratings and balance sheet strength matter and the other thing it taught me is that Duke Energy Corporation … relies on the global markets for its capital and so when bad things do happen in the capital markets, it does affect Duke Energy Carolinas. … And so having a rating of A- enabled Duke Energy Carolinas to get through the financial crisis; not without difficulty but we were able to access capital at all times…
>
> (T Vol. 4, pp. 27-28).

Witness Fetter further testified that the capital structure of 47% debt and 53% equity, as reflected in the Settlement, represents the Company's actual capital structure, which matches the capital structure guidance that Standard & Poor's (S&P) publicly provides for a utility with Duke Energy Carolinas' financial risk and business risk characteristics. According to witness Fetter, the 47.5% debt, 52.5% equity capital structure approved by the Commission in Docket No. E-7, Sub 909, coupled with an authorized ROE level of 10.7%, has allowed the Company to maintain a strong credit profile. He believes that an authorized ROE of 10.5% coupled with the Company's actual capital structure as provided for in the Stipulation will allow Duke Energy Carolinas to maintain its current A-category credit rating status.

Public Staff witness Johnson recommended that the Commission use a capital structure composed of 50% long-term debt and 50% common equity in his pre-settlement direct testimony. He testified that his recommended equity ratio is less than the actual equity ratio of Duke Energy. However, since the unregulated and overseas operations of Duke Energy are riskier than Duke Energy Carolinas' regulated operations in North Carolina, it is reasonable to assume the optimal equity ratio of North Carolina regulated operations is lower than the overall consolidated enterprise.

Witness Johnson testified that his analysis of 41 firms included in Value Line's electric group as shown in Schedule 1 of his testimony, excluding short-term debt and preferred stock financing, resulted in an overall average equity ratio of 47.4%. He testified that his 50% recommended common equity ratio is less costly than the 53% ratio requested by the Company, but is more conservative and somewhat more costly than the overall average 47.4% equity ratio for the 41 electric company comparable group.

CUCA witness O'Donnell agreed with the use of the capital structure proposed by Duke Energy Carolinas for purposes of this proceeding. Additionally, CUCA indicated, on the record, that it does not oppose the Stipulation.

The Attorney General argued that Duke Energy Carolinas' customers should not be required to pay higher rates simply because the Company prefers to maintain a higher level of equity, as opposed to debt, on its books. The Attorney General averred that while 0.5% may seem trivial on its face the testimony in the record shows that "for each half a percentage point of equity within the capital structure the impact is approximately $7.6 million on what Duke Energy Carolinas' customers will be required to pay in rates." According to the Attorney General, a capital structure composed of 50% debt and 50% equity is more conservative and more costly to ratepayers than the industry average, but it is considerably more equitable to ratepayers than the capital structure proposed by Duke Energy Carolinas.

The Attorney General is of the opinion that in no event should an equity ratio higher than 52.5% (the ratio allowed Duke Energy Carolinas in its last general rate case proceeding) be used to establish rates in this case. According to the Attorney General, Duke Energy Carolinas presented no evidence as to why its equity capitalization ratio should be increased by an additional 50 basis points.

The Attorney General commented that Duke Energy Carolinas' actual capital structure had varied over time from that previously employed by the Commission and that if Duke Energy Carolinas believed that a capital structure composed of 47% debt and 53% equity remains preferable going forward it can continue to maintain those ratios on its books. However, the Attorney General is of the opinion that Duke Energy Carolinas' ratepayers should not be required to pay an additional $7.6 million in rates, per 50 basis points increase in the Company's equity capitalization ratio, because of Duke Energy Carolinas' preference, without any evidence in the record, according to the Attorney General, that such an increase in equity capitalization is necessary or appropriate.

Based upon the foregoing testimony and the entire record in this proceeding, the Commission finds and concludes that the capital structure set forth in the Stipulation, 47% long-term debt and 53% common equity, should be adopted for purposes of this proceeding. The Commission concludes that this capital structure is reasonable and in the public interest based on several factors, including the Stipulation's resolution of numerous highly contested issues. All expert witnesses presenting testimony in this proceeding consider the aforesaid capital structure to be appropriate and within the bounds of reasonableness. Further, no intervenor not a party to the Stipulation presented evidence suggesting that a different capital structure would be more appropriate than that provided in the Stipulation. In addition, in his testimony supporting the Stipulation, Public Staff witness Johnson testified that the capital structure contained in the Stipulation is acceptable in the context of the total Stipulation provisions, even though it departed from the 50% debt, 50% equity capital structure he recommended in his direct testimony.

Therefore, the Commission finds and concludes that a capital structure of 47% long-term debt and 53% common equity for Duke Energy Carolinas is just and reasonable to all parties in light of all the evidence presented.

Return on Equity

The Company requested approval for its rates to be set using an ROE of 11.5% in its Application, which was adjusted to 11.25% by Company witness Hevert in his rebuttal testimony. Public Staff witness Johnson recommended an ROE of 9.25%. CUCA witness O'Donnell recommended a 9.5% ROE. The Stipulation provides for an ROE of 10.5%.

Company witness Hevert testified in support of the Company's original request as stated in the Application. In his direct testimony, he recommended an ROE of 11.5%, which was slightly above the midpoint of his recommended range of 11% to 11.75%. Based on the updated data and analyses contained in his rebuttal testimony, he decreased his ROE range to 10.75% to 11.5%, and revised his recommended ROE to 11.25%.

Witness Hevert testified that the ROE, or cost of equity, is the return that investors require in order to be compensated for the risks associated with owning common equity. Unlike the cost of debt, the cost of equity is neither contractual nor observable, and must be estimated based on market data. Witness Hevert relied on both the Discounted Cash Flow (DCF) and the Capital Asset Pricing Model (CAPM) to estimate the cost of equity, although he placed greater weight upon the results of the DCF approach. He explained that since both financial models produce a range of quantitative results, the question becomes one of where the Company's cost of equity lies within that range. To inform that decision, witness Hevert considered both capital market and company-specific risks in determining the Company's ROE. In his direct testimony, witness Hevert concluded those factors suggested an ROE slightly above the midpoint of his range.

Witness Hevert's rebuttal testimony updated the analyses contained in his direct testimony. As with his direct testimony, the updated analyses included several observable measures of market risk and volatility. His rebuttal testimony applied his analyses to all of the proxy groups proposed by each of the ROE witnesses and included a multi-stage form of the DCF model, which, according to witness Hevert, is a more refined version of the constant growth DCF model used in his direct testimony. Witness Hevert explained that those updated analyses, in particular the DCF-based analyses, led him to reduce his ROE range and recommendation by 25 basis points.

Public Staff witness Johnson also provided testimony regarding the Company's cost of equity. Witness Johnson utilized both a comparable earnings approach and a market approach to determine his recommended ROE. With respect to his comparable earnings approach, witness Johnson testified that he believes the equity risks facing the Company in its North Carolina electric operations are a bit lower than typical utilities, taking into consideration the Company's large and diverse service territory, its supportive regulatory climate, and the conservative capital structure he is using for ratemaking purposes. He testified he also took into account the large size of Duke Energy Carolinas' ongoing construction program; noting that while the regulatory environment provides a supportive context for this program, it does not completely eliminate the associated risks. Witness Johnson testified that balancing all of these factors, the Company's cost of equity under the comparable earnings approach is in the range of 9.75% to 10.75%.

With respect to the market approach to estimating the Company's cost of equity, witness Johnson testified that he developed three sets of distinct calculations. First, he used actual market returns adjusted for differences in risk, which, according to witness Johnson, suggested the Company's cost of equity is currently in the vicinity of 8.5% to 9.5%. Second, witness Johnson testified that he prepared a DCF analysis for a comparable group of 41 electric utilities, which suggested a cost of equity of about 7.5% to 9% for the Company's North Carolina operations. Third, witness Johnson developed a CAPM analysis, which suggested a cost of equity of 6.92% to 7.82%.

Witness Johnson noted that the results of these different methods cover a wide range, so the final conclusion one reaches concerning the cost of equity depends on how much weight is given to each method. While this is clearly a matter of discretion for the Commission, he generally recommends focusing on the central portion of the data, rather than the extreme values. He testified that if the Commission were to focus on the midpoints of his comparable earnings and market results, and give approximately equal weight to each of these methods, the estimated cost of equity would be approximately 9.25%.

CUCA witness O'Donnell provided testimony regarding the Company's cost of equity. Witness O'Donnell used both the DCF method and a comparable earnings method. His DCF results yielded a cost of equity range of 8.75% to 9.75% for Duke Energy Carolinas. His comparable earnings analysis yielded an ROE ranging from 8.5% to 9.5%. Witness O'Donnell recommended an ROE of 9.5%, as the middle of the range of the DCF results for the comparable group and Duke Energy Carolinas and the high end of the range for the comparable earnings analysis. Though witness O'Donnell did not present oral testimony at the evidentiary hearing, counsel for CUCA read into the record a portion of the prepared summary of witness O'Donnell's pre-filed testimony which counsel for CUCA characterized as a summary of CUCA's position in this case. In the summary, witness O'Donnell concluded, "I have been informed that CUCA has changed its position and now agreed not to oppose the settlement reached between Duke and the Public Staff so while I am not withdrawing or changing my prefiled testimony, my official position is to support the decision my client has made."

Commercial Group witness Chriss does not recommend a specific ROE. Rather, he observed that the 11.5% recommendation contained in Company witness Hevert's direct testimony exceeds the Company's currently authorized return of 10.7% and recently authorized ROEs across the country which, he suggests, have been in the range of 10.25% to 10.42%, with an average authorized return of 10.32%. Witness Chriss also suggests that although the Company's proposed merger with Progress Energy Carolinas, Inc. (PEC) did not close during the test year, the rates in effect as a result of this docket "likely will be in effect after the companies have been combined."

Company witness Hevert noted that Commercial Group witness Chriss has not suggested that the Commission make an adjustment for the Company's proposed merger with PEC, a transaction that has not yet closed. He testified that he agrees that it is appropriate to view Duke

Energy Carolinas without respect to the proposed merger and does not believe that any adjustment to the Company's ROE relating to the combined companies is appropriate.

Witness Johnson observed that in Section 2 of the Stipulation, the Stipulating Parties agree to a total increase in annual sales revenues of $309,033,000 from Duke Energy Carolinas' North Carolina retail electric operations, and they state that these revenues "are intended to provide Duke Energy Carolinas, through sound management, the opportunity to earn a return on equity of 10.5%." He testified the Stipulating Parties also agreed to an embedded cost of debt of 5.41%, and agreed to use an 8.11% overall rate of return to develop the $309,033,000 rate increase.

Witness Johnson testified that the allowed return set forth in the Stipulation is not unreasonable, particularly in the context of a settlement that resolves numerous other highly contested issues without the expenses and delays of continued litigation. He testified that providing Duke Energy Carolinas with a $309,033,000 rate increase and an opportunity to earn a return that exceeds his determination of its actual cost of capital is reasonable and consistent with the public interest.

Company witness Hevert testified that while he recognizes that the 10.5% ROE included in the Stipulation is 25 basis points below the low end of his recommended range and 75 basis points below his specific recommendation, it is within the range of the mean analytical results presented in his rebuttal, in particular his DCF-based models. In addition, according to witness Hevert, the consistency of regulation and the extent to which regulatory decisions support utilities' financial integrity are important considerations from the perspective of investors and are goals the Stipulation seeks to achieve.

Duke Energy Carolinas witness De May testified that he believes that the financial strength and flexibility afforded by the Company's current credit ratings and balance sheet strength are in the best interest of customers because they help the Company maintain access to capital on reasonable terms, even in challenging market conditions, and allow the Company to better deal with unforeseen events, while still meeting its obligation to serve. He added that, taken as a whole, the Stipulation represents a constructive outcome that should not have an adverse impact to the Company's credit ratings and financial position. Similarly, Company witness Fetter testified that he believes that an authorized ROE of 10.5% coupled with the Company's actual capital structure as provided in the Stipulation will allow the Company to maintain its current A-category credit rating status.

In his brief, the Attorney General first argued that there is insufficient evidence in the record to allow the Commission to establish a reasonable return pursuant to G.S. 62-133 because the expert witnesses failed to consider the impact of changing economic conditions on consumers when making the ROE analyses and recommendations. However, the Commission does not find this argument persuasive. Duke witness Hevert and Public Staff witness Johnson testified that it is not necessary to consider the impact of changing economic conditions on consumers in the context of an ROE economic analysis, other than in a broader macroeconomic sense, when analyzing changing market conditions for the purpose of making ROE recommendations. However, the Commission is required to consider the economic effects of its

ROE decision on a public utility's customers pursuant to G.S. 62-133(b)(4). In particular, G.S. 62-133(b)(4) states, in pertinent part, that in fixing rates the Commission must fix a rate of return on the utility's investment that "will enable the public utility by sound management to produce a fair return for its shareholders, considering changing economic conditions and other factors, including, but not limited to…to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and to its existing investors." One of the "terms" on which a public utility competes in the market for capital funds is the utility's authorized ROE. Thus, the Commission must consider whether that term is reasonable and fair to the utility's customers. Public Staff witness Johnson testified in depth concerning the economic downturn, including the unemployment rate. In addition, the Commission received extensive testimony from public witnesses concerning the impact of current economic conditions on Duke's customers. Therefore, the Commission has ample evidence to consider in determining whether the proposed ROE of 10.5% is fair to Duke's customers.

Alternatively, the Attorney General argued that should the Commission decide there is sufficient evidence in the record to determine an appropriate ROE, the Commission should adopt an ROE below the 10.5% proposed in the Stipulation. In support of this argument, the Attorney General states that North Carolinians face economic challenges and a rate increase will have a detrimental impact on consumers who are finding it hard to make ends meet. In addition, the Attorney General proffers that the expert testimony largely consisted of educated guesses as to investor requirements, and, in the unlikely event that there is an adverse market reaction to an ROE below 10.5%, the Commission will be in a position to make adjustments, if deemed appropriate, in the context of the rate increases that Duke has indicated it will seek later this year. Further, the Attorney General stated that none of the expert testimony specifically supported the 10.5% ROE set forth in the Stipulation, and the expert testimony in the record does not support the 10.5% ROE in the Stipulation.

However, the Commission notes that Public Staff witness Johnson, who performed extensive analyses and presented his recommendation with respect to the specific cost of equity capital, testified that an ROE of 10.5% was not unreasonable when considered in the context of the overall Stipulation provisions. He also testified that providing Duke with an opportunity to earn a return that exceeded his 9.25% determination of the Company's actual cost of equity was reasonable and consistent with the public interest in the context of the Stipulation. Further, CUCA, also having presented an expert cost of capital witness, who performed extensive analyses and who concluded that Duke's cost of equity was 9.75%, does not oppose the Stipulation, including the 10.5% ROE provided therein.

Finally, the 10.5% ROE provided for in the Stipulation is within the range between the Public Staff's initial position (9.25%) and the Company's requested ROE (11.25%). A 10.5% ROE is also within the range of ROE levels produced by the quantitative analyses conducted by the ROE witnesses who conducted such analyses in this case. The 10.5% level is supported, in the context of the overall settlement documented by the Stipulation, by all of those witnesses as well. In the context of the Stipulation and consistent with the testimony of the Public Staff's and Company's cost of capital witnesses at hearing, the Commission finds and concludes that the Stipulating Parties' recommended return on common equity of 10.5% is just and reasonable to all parties in light of all the evidence presented.

Cost of Debt

The Company proposed a long-term debt cost of 5.41%. The Stipulation also provides for a long-term debt cost of 5.41%.

Public Staff witness Johnson testified that he was not necessarily endorsing every detail of the calculations used in developing the Company's proposed debt costs. However, he testified the basic approach is a sound one, and the resulting cost rates appear to be reasonable and consistent with the Commission's past practice. Witness Johnson recommended the acceptance of the embedded cost of long-term debt of 5.41%.

No party provided any evidence to dispute the use of 5.41% as the cost of long-term debt. The Commission finds and concludes that the use of a long-term debt cost of 5.41% is just and reasonable to all parties in light of all the evidence presented.

Revenue Increase

Duke Energy Carolinas, by its application and initial direct testimony and exhibits, originally sought an increase of $646,057,000 or 15.2% in its annual non-fuel revenues from its North Carolina retail electric operations. On October 7, 2011, the Company filed supplemental direct testimony and exhibits updating its cost of service in a manner that supported a base rate increase of $622,473,000. On October 14, 2011, the Company filed second supplemental direct testimony and exhibits supporting a base rate increase of approximately $637,969,000. This filing included the following amounts of test year pro forma operating revenues, operating revenue deductions, and original cost rate base (under present rates): $4,332,984,000 of operating revenues; $3,745,184,000 of operating revenue deductions; and $11,147,708,000 of original cost rate base.

On November 1, 2011, the Public Staff filed direct testimony recommending several adjustments to the Company's proposed increase of $637,969,000; as a result, the Public Staff concluded that a base rate increase of $211,119,000 was appropriate, with much of the reduction from the Company's request resulting from the Public Staff's recommendation regarding cost of capital, *i.e.*, the Public Staff's adjustment to lower the ROE to 9.25%, reduced the revenue requirement by $213,299,000. The Public Staff's recommendation included $4,388,564,000 of operating revenues, $3,701,027,000 of operating revenue deductions, and $11,073,247,000 of original cost rate base. The Public Staff witnesses provided testimony summarizing their recommended accounting and ratemaking adjustments to the Company's proposed rate base and cost of service. For example, Public Staff witness Peedin recommended 16 adjustments, including reductions to the Company's lobbying expenses, property taxes, and officers' compensation. Public Staff witness Crean proposed adjustments to the Company's lead-lag study, benefits expense, and adjustments relating to coal inventory, among other things. Public Staff witnesses Johnson, Floyd, Lucas, and Hinton also recommended specific adjustments. The Public Staff's pre-Stipulation recommended adjustments were summarized in Peedin Exhibit I, Schedule 1.

No other party filed testimony challenging Duke Energy Carolinas' accounting and pro forma adjustments, with the exception that certain intervenors, as previously discussed, opposed Duke's proposals regarding capital structure and ROE.

The Company filed rebuttal testimony on November 16 and 17, 2011, further updating its cost of service by accepting or choosing not to contest a number of the adjustments recommended by the Public Staff and reducing its requested ROE to 11.25%. As a result, the Company updated its proposed increase in its annual North Carolina retail electric revenues to a requested increase of $525,003,000.

On November 28, 2011, Duke Energy Carolinas and the Public Staff filed a Stipulation, comprehensively resolving all issues in this proceeding between themselves. On December 1, 2011, the Public Staff filed a correction to the Stipulation, with which the Company agreed. On December 2, 2011, Duke Energy Carolinas, Time Warner, and the Public Staff filed an Amendment to Agreement and Stipulation of Settlement adding Time Warner as a Stipulating Party. Further, on January 4, 2012, the Stipulating Parties filed a second amendment to the Stipulation.

The Stipulation provides for a net increase of $309,033,000 or 7.21% in Duke Energy Carolinas' annual revenues from kWh sales from its North Carolina retail electric operations. Duke Energy Carolinas submitted evidence in this case with respect to revenues, expenses, and rate base using a test period consisting of the 12 months ended December 31, 2010, updated for certain known and actual changes. The Stipulation is based upon the same test period.

Pursuant to the Stipulation, the Stipulating Parties have agreed upon the following amounts of test year pro forma operating revenues, operating revenue deductions, and original cost rate base (under present rates) to be used as the basis for setting rates in this proceeding: $4,409,946,000 of operating revenues; $3,726,277,000 of operating revenue deductions; and $10,673,442,000 of original cost rate base. The Stipulating Parties provided a detailed breakdown of these amounts in Settlement Exhibit 3 to the Stipulation.

Prior to entering into the Stipulation, Company witnesses provided rebuttal testimony challenging the propriety of some of the Public Staff's adjustments, but agreeing with others. For example, the Company accepted the Public Staff's adjustments for present revenues related to BPM sales, aviation expenses, officers' compensation, and lobbying expenses, among others. These items were specifically included as line item adjustments in deriving the stipulated revenue increase, as provided in Settlement Exhibit 1 to the Stipulation. Further, the Stipulation itself addresses many of the other adjustments recommended by the Public Staff (e.g., vegetation management policy and procedures, and the stopped meter issue).

Settlement Exhibit 1 to the Stipulation details the revenue requirement impact of adjustments to the Company's position to reach settlement, including: adjusting the ROE from 11.25% to 10.5% ($100,486,000); removing VOP costs associated with the Midwest office consolidation and adjusting the VOP amortization period ($11,351,000); adjusting property taxes ($5,092,000); and adjusting pension settlement costs and the amortization period ($4,781,000).

The Commission recognizes that a settlement necessarily involves negotiation and compromise. The Stipulating Parties need not show line-by-line how they arrived at the stipulated revenue increase provided they show by substantial evidence, in light of the record as a whole, that the revenue increase should allow the Company to recover its estimated cost of capital and expenses, but not burden ratepayers with a revenue requirement above a reasonable estimate of the cost of capital and expenses. The Commission is of the opinion that the Stipulating Parties have made such a showing. Consequently, the Commission finds and concludes that the following amounts under the Stipulation are appropriate and reasonable for purposes of setting rates in this proceeding: $4,718,979,000 of operating revenues; $3,853,608,000 of operating revenue deductions; and $10,673,442,000 of original cost rate base.

Based upon its conclusions as set forth in this Order, the Commission has reviewed the Stipulation's provision for an annual non-fuel revenue increase of $309,033,000 and finds and concludes that this increase in the level of base rates to be paid by Duke Energy Carolinas' North Carolina retail customers, resulting in an overall rate of return of 8.11% on jurisdictional rate base and an ROE of 10.5% using a capital structure comprised of 47% long-term debt and 53% common equity, is just and reasonable to all parties in consideration of all the evidence presented in this proceeding. The following schedules summarize the gross revenues and the rate of return that the Company should have a reasonable opportunity to achieve based upon the determinations made herein. These schedules, illustrating the Company's gross revenue requirement, incorporate the findings and conclusions made by the Commission in this Order. As reflected below in Schedule I, and as impacted by the other findings in this Order, Duke Energy Carolinas is authorized to increase its annual level of operating revenues by $309,033,000, based upon the adjusted test year level of operations:

SCHEDULE I

DUKE ENERGY CAROLINAS, LLC

North Carolina Retail Operations
Docket No. E-7, Sub 989
STATEMENT OF OPERATING INCOME
Twelve Months Ended December 31, 2010, as Adjusted
(000s Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Electric operating revenues	$4,409,946	$309,033	$4,718,979
Operating revenue deductions:			
Operations and maintenance expenses:			
Fuel used in electric generation	1,203,925	-	1,203,925
Purchased power and net interchange	166,579	-	166,579
Wages, benefits, materials, etc.	1,171,975	371	1,172,346
Depreciation and amortization	624,682	-	624,682

General taxes	279,226	9,951	289,177
Interest on customer deposits	4,735	-	4,735
Income taxes	280,344	117,009	397,353
Amortization of investment tax credit	(5,189)	-	(5,189)
Total operating revenue deductions	3,726,277	127,331	3,853,608
Net operating income for return	$ 683,669	$181,702	$ 865,371

SCHEDULE II

DUKE ENERGY CAROLINAS, LLC

North Carolina Retail Operations
Docket No. E-7, Sub 989
STATEMENT OF RATE BASE AND RATE OF RETURN
December 31, 2010, as Adjusted
(000s Omitted)

Item	Amount
Electric plant in service	$20,620,597
Accumulated depreciation and amortization	(9,040,838)
Net electric plant in service	11,579,759
Materials and supplies	523,173
Working capital allowance	622,563
Operating reserves	(232,185)
Accumulated deferred income taxes	(2,535,592)
Construction work in progress	715,724
Total original cost rate base	$10,673,442
Overall rates of return:	
Present rates	6.41%
Approved rates	8.11%

SCHEDULE III

DUKE ENERGY CAROLINAS, LLC

North Carolina Retail Operations
Docket No. E-7, Sub 989
STATEMENT OF CAPITALIZATION AND RELATED COSTS
Twelve Months Ended December 31, 2010, as Adjusted
(000s Omitted)

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost Rates	Net Operating Income
		Present Rates – Original Cost Rate Base		
Long-term debt	47.00%	$ 5,016,518	5.41%	$271,394
Common equity	53.00%	5,656,924	7.29%	412,275
Total	100.00%	$10,673,442	-	$683,669
		Approved Rates – Original Cost Rate Base		
Long-term debt	47.00%	$ 5,016,518	5.41%	$271,394
Common equity	53.00%	5,656,924	10.50%	593,977
Total	100.00%	$10,673,442	-	$865,371

EVIDENCE SUPPORTING FINDING OF FACT AND CONCLUSION NO. 12

The evidence supporting this finding of fact and conclusion is contained in the Stipulation, Duke Energy Carolinas' verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

As part of the Stipulation, the Company agreed to waive its right to increase the amount of CWIP in rate base for any expenditures associated with Cliffside Unit 6 above the North Carolina retail portion of the $1,023,521,000 system amount included in the Company's rate base in Docket No. E-7, Sub 909. Instead, the Company will continue to capitalize AFUDC on all expenditures associated with Cliffside Unit 6 not included in rate base since the Commission's Order in Docket No. E-7, Sub 909.

Company witness Carter testified that the Company is waiving its statutory right to increase the amount of CWIP to mitigate the impact of the rate increase. In response to an inquiry from Commissioner Culpepper, witness Carter confirmed that the Company and Public Staff are in agreement that $51,195,000 is the correct amount.[1]

Because the Company will continue to accrue AFUDC on the Cliffside Unit 6 CWIP that is not included in rate base in this proceeding, the Company will recover its full costs. However, this recovery is postponed to a future period. No party has opposed this proposal. The Commission concludes that this is a reasonable approach for mitigation of the impact of the rate increase on customers during the current difficult economic circumstances. This provision of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

[1] This amount represents the revenue impact of not including all of the eligible Cliffside Unit 6 CWIP in rate base in this proceeding.

EVIDENCE SUPPORTING FINDING OF FACT AND CONCLUSION NO. 13

The evidence supporting this finding of fact and conclusion is contained in the Stipulation, Duke Energy Carolinas' verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

The Clean Air Act Amendments enacted in the early 1990s created the concept of emission allowances. The EPA allotted a certain number of emission allowances to the various utilities. In order to create a future market for those emission allowances the EPA withheld 2.8% of the allowances that were allotted to the various utilities to be auctioned on an annual basis. The EPA auctions began in 1993. The proceeds from the auction of the emission allowances are returned or sent to the utilities from which the EPA had withheld the allowances.

Company witness Shrum testified that Duke Energy Carolinas became a Phase II Clean Air compliant company participant in 2000, resulting in return of proceeds from that EPA auction. She explained that, in accordance with FERC guidance at that time, because there was no regulatory certainty as to how to handle those auction proceeds, they were included in a regulatory liability account, Account 254. The Company has continued to include the annual proceeds from those auctions in that account. There is approximately $8.1 million of EPA auction proceeds currently in the account allocable to North Carolina on a North Carolina retail basis. The Stipulating Parties seek approval in this rate case to allow these funds to be returned to customers.

No party has opposed the use of the EPA auction proceeds for the benefit of ratepayers in this proceeding. The Commission finds and concludes, that pursuant to the Stipulation, the Company shall, as part of this proceeding, flow through to customers the North Carolina retail allocated share of its September 30, 2011, balance of the accumulated EPA sulfur dioxide auction proceeds maintained to date as a regulatory liability in the Company's books and records.

EVIDENCE SUPPORTING FINDING OF FACT AND CONCLUSION NO. 14

The evidence supporting this finding of fact and conclusion is contained in Duke Energy Carolinas' verified Application and Form E-1, the testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

Duke Energy Carolinas based its filing in this case on the SCP methodology for allocating its cost of service among jurisdictions and among customer classes. Public Staff witness Floyd filed testimony setting forth the Public Staff's position that the SWPA allocation methodology is preferable. CUCA witness O'Donnell, CIGFUR III witness Phillips, and Kroger witness Higgins filed testimony supporting the use of the SCP methodology in the cost of service study in this case. In its Brief, the Advocacy Group requested that the Commission use the SWPA methodology.

Company witness Stillman provided testimony in support of the SCP methodology for allocation among jurisdictions and among customer classes. He explained that the coincident peak allocator is developed based on the contribution that each jurisdiction and the customer classes within the jurisdiction made to the system's peak demand experienced during the test year. The peak generation demand used in the Company's cost-of-service study for the test year occurred on August 11, 2010, at 5:00 p.m. The peak transmission demand used in this study occurred on July 23, 2010, at 4:00 p.m.

Witness Stillman explained that a coincident peak allocator based on peak responsibility means certain production and transmission plant and plant-related costs that are incurred to meet the maximum hourly demand on the system will be assigned to those customer groups, and as a result the appropriate jurisdiction, that caused the system's maximum hourly demand. Each jurisdiction's and customer class' cost responsibility is equal to the ratio of their demand in relation to the total demand placed on the system. Witness Stillman testified that the cost of service study that supports the Company's proposed rate design in this proceeding allocates production and transmission demand-related costs based upon the coincident peak responsibility occurring during the summer.

Witness Stillman testified that SCP is still the appropriate allocator for use in allocating production plant costs in this proceeding. According to witness Stillman, the Company's historical load profile reflects a predominant summer peak. Over the last 25 years, the Company has experienced only two winter peaks, occurring in 1986 and 1994. Over that same period, the summer peak has exceeded the winter peak by an average of 11%, and has been as great as 26% higher than the corresponding winter peak. Over the past five years, the Company's summer peak has exceeded its corresponding winter peak, on average, by 11%. Witness Stillman explained that even during 2009 and 2010, when the economic downturn greatly influenced the Company's summer peak and extreme weather influenced both the summer and winter months, the Company's summer peak still exceeded the winter peak.

Witness Stillman also testified that through its integrated resource planning process the Company continues to plan to meet its future resource needs in order to meet its projected maximum summer load obligation (plus a reserve margin). Over the 20-year planning horizon of the Company's 2010 Integrated Resource Plan (IRP), the average winter reserve margin is greater than the average summer reserve margin by more than 25%. The 2010 IRP and its load forecasting data support the position that the Company's summer peak will continue to be the predominant peak experienced by the Company and will continue to drive the Company's resource planning process. Witness Stillman concluded that it is appropriate to assign fixed demand-related costs on the basis of the SCP methodology, as an allocation methodology that does not adequately account for the Company's dominant SCP would both fail to reflect the actual load characteristics of the Company's system that give rise to the costs and fail to accurately reflect cost-causation principles.

Public Staff witness Floyd testified in support of the SWPA methodology for allocation of certain costs among jurisdictions and among customer classes. He explained that under the SWPA methodology the fixed costs of production plant are allocated among jurisdictions and customer classes on the basis of a formula that contains two components. The first component, the "summer/winter peak" component, is based on the actual demand of the jurisdiction or customer class in question at the time of the utility's summer and winter peaks during the test year. The second component, the "average" component, is based on the average demand of the jurisdiction or customer class, *i.e.*, total kilowatt-hour (kWh) sales for the test year divided by the total number of hours in the test year. In other words, the first component is based on jurisdictional or customer demand at particular points in time, *i.e.*, the annual summer and winter one-hour peaks, and the second component is based on the average jurisdictional or customer demand over the entire year.

Witness Floyd asserted that the SWPA methodology recognizes that some production plant costs are incurred because of the need to provide sufficient capacity during peak periods, while other production plant costs are incurred because of the need to provide low-cost energy during all hours. Witness Floyd explained that when there is a need for new capacity there are generally three types of generation resources to consider: peaking units, intermediate or cycling units, and baseload units. While a utility must always plan its system to meet the annual peak load(s), the ultimate selection of the "type" of unit to build is an economic decision based on the energy (kWh) requirement or the number of hours a unit must operate each year. Witness Floyd asserted that if little energy is required, peaking units are cost-justified due to their lower capital cost as compared to large baseload units. However, if much energy is needed, the lower energy cost (in cents/kWh) of capital-intensive baseload units makes them more desirable. Therefore, according to witness Floyd, it is logical to conclude that, while some production plant costs are incurred because of the one-hour summer and winter peaks, some plant costs are also incurred because of the energy or hours-of-use requirement of the plant. The SWPA methodology recognizes that a portion of production plant costs, particularly for baseload generation, is incurred to meet annual energy requirements and not solely to meet peak demand.

Further, witness Floyd offered the following in support of the use of the SWPA methodology: (1) the Company's summer and winter peaks were not substantially different from one another because the seasonal peaks have become more closely aligned such that the test period summer peak was only 1.6% greater than the winter peak; (2) the Company's system load factors were not substantially different from those of Progress Energy Carolinas (PEC) or Dominion North Carolina Power (DNCP) over the last 10 years (both of which utilize the SWPA methodology); and (3) the Company's recent IRP included a mix of new capacity and energy resources over the planning horizon, including significant amounts of new baseload capacity.

In rebuttal testimony, Duke Energy Carolinas witness Stillman asserted that witness Floyd's stance that "Duke's summer and winter peaks are not substantially different from one another" is based solely upon the Company's reported 2009 and 2010 peaking statistics. Witness Stillman asserted that Stillman Rebuttal Exhibit 1, which presented the summer and winter peaks from the last 10 years as reported in Floyd Exhibit 1, showed that when taking a longer term view of Duke Energy Carolinas' system peaking characteristics, on average, the summer peak is 13% greater than the winter peak. Witness Stillman testified that when relying on the peaking statistics of 2009 and 2010, it is necessary to consider the influence the economic downturn has had on the Company's summer peak during that period. He explained that if 2009 and 2010 are excluded from the sample range, Duke Energy Carolinas' average summer peak exceeds it average winter peak by 16%. Witness Stillman opined that a significant change to the Company's long standing cost allocation methodology should not be based upon such a short term view of the Company's peaking characteristics.

With respect to witness Floyd's assertion that Duke Energy Carolinas' system load factors were not substantially different from those of PEC or DNCP over the last 10 years, witness Stillman testified that the similarities that witness Floyd attempts to demonstrate are either not evident or are at far too high a level to be useful in determining if similar cost of service allocation methodologies should be considered by the three companies. Witness Stillman explained that Stillman Rebuttal Exhibit 1, which presents the summer and winter peaks for the last 10 years for the Company, PEC and DNCP, showed that Duke Energy Carolinas has not experienced a winter peak over such time period, whereas both PEC and DNCP have peaked during the winter. Witness Stillman further explained that Stillman Rebuttal Exhibit 1 also demonstrates that the respective differential between the summer and winter peaks of the three companies is far greater for Duke Energy Carolinas (13% difference) than it is for PEC or DNCP (4% and 8%, respectively).

CUCA witness O'Donnell testified that the SCP methodology is the proper allocation method to model the Duke Energy Carolinas system since the utility builds generating plant to meet the peak demand on its system and, as a result, it makes sense to allocate generation investment by the coincident peak ratio. Witness O'Donnell stated that the residential customer class is the most temperature-sensitive and time-sensitive customer class served by Duke Energy Carolinas. Witness O'Donnell explained that as temperatures rise, residential consumers respond by running their air conditioners more frequently. The time at which residential consumers use the most electricity is typically the late afternoon hours of a hot summer day when workers return home from work. Witness O'Donnell opined that to accommodate the need for electricity the Company must ramp up its more expensive generating plants to meet this summer peak demand. Witness O'Donnell stated that, in contrast, industrial consumers keep their energy consumption relatively level since these customers are much less sensitive to temperature fluctuations than are residential customers.

CIGFUR III witness Phillips and Kroger witness Higgins supported the use of the SCP methodology as proposed by the Company.

NC WARN, et al., witness Cook testified regarding his concerns about the electricity demand of data centers, the rates and incentives being offered by Duke Energy Carolinas to secure data center investment, and the subsidies to the data center rates by residential customers. Witness Cook explained that the data centers are used to house virtual information, part of the cloud infrastructure, and that such data centers are actively being sought by Duke Energy Carolinas as they represent some of the largest consumers of electricity that can be found, with consumption varying little by season or from economic downturn. Witness Cook described the current data centers in North Carolina, including Apple Computer in Maiden, Google in Lenoir, Facebook in Forest City, and IBM in the Research Triangle Park. Witness Cook opined that if Duke Energy Carolinas sets its rates based upon the SCP methodology, a greater overall percentage of the costs of new generating facilities would be borne by the residential customers who consume power at the summer peak. Witness Cook asserted that the data centers, which require the new baseload capacity all year long, would only pay for the percentage they use on the summer peak. According to witness Cook, the data centers are billed under the Company's OPT-H tariff and approximately 78% of the electricity used by those customers is off-peak.

In its Brief, NC WARN, et al., observed that, according to the Stipulation, all customer classes would receive an identical 7.21% increase and that since the proposed rates in the Stipulation were based upon the rates established in Duke Energy Carolinas' 2009 rate case, which used the SCP methodology, any inequities between the various customer classes resulting from the reliance on the SCP methodology would continue. NC WARN, et al., recommended that the Commission approve rates in this proceeding based upon the SWPA allocation methodology because such methodology more fairly allocates costs by considering both the energy component as well as peak demand.

In rebuttal testimony, Duke Energy Carolinas witness Bailey testified that witness Cook's assertion that residential customers are subsidizing data centers is baseless because "the level of service, load factors, and rate designs of these incredibly disparate customer classes simply defy any direct comparison." On cross-examination, witness Bailey testified that if the Company did change its allocation methodology, "…there would not be an appreciable change in terms of how one class relates to another; some minor shift, yes; major? Very unlikely."

In the Stipulation at Paragraph 4.B., the Stipulating Parties agreed that the SCP methodology may be used in the current proceeding, but that such use of the SCP methodology shall not be a precedent for and may be contested in future general rate case proceedings, and that Duke Energy Carolinas will continue to file annual cost of service studies based on both the SCP and SWPA methodologies. The Company also agreed that it will not cite Commission approval of the Stipulation as support for approval of the SCP methodology in future proceedings.

The Commission finds and concludes that while the parties have disagreed as to the appropriate allocation methodology the Company should use to allocate the costs of production plant, it is not unreasonable for the Stipulating Parties to have agreed, as part of their overall settlement of all contested issues, that the allocation of production plant costs based on the SCP methodology is reasonable for purposes of this proceeding. Therefore, the Commission accepts the Stipulating Parties' settlement to use the SCP methodology. However, the Commission's acceptance of the SCP methodology for cost allocation among jurisdictions and among customer classes in this proceeding shall not be a precedent for and may be contested in future general rate case proceedings. Furthermore, the Company shall continue to file annual cost of service studies based on both the SCP and SWPA methodologies. In addition, as provided in the Stipulation at Paragraph 4.B., the Company shall not cite Commission approval of the Stipulation as support for approval of the SCP methodology in future proceedings.

EVIDENCE SUPPORTING FINDING OF FACT AND CONCLUSION NO. 15

The evidence supporting this finding of fact and conclusion is contained in the Stipulation, Duke Energy Carolinas' verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

The Stipulating Parties agree to a base fuel and fuel-related cost factor of 2.3935 cents per kWh, excluding gross receipts tax and regulatory fee, which constitutes a composite of the fuel and fuel-related cost factors approved by the Commission in Docket No. E-7, Sub 982, for the residential, commercial, and industrial classes.

Witness McManeus provided testimony supporting a base fuel and fuel-related costs factor (excluding gross receipts tax and regulatory fee) of 2.3935 cents per kWh, which was the composite of the residential, commercial, and industrial fuel and fuel-related costs factors, excluding the Experience Modification Factors, as approved by the Commission in Docket No. E-7, Sub 982. She explained that this fuel factor was based upon the 12 month period ending December 31, 2010, and took into consideration known and measurable changes for 2011 and 2012.

The fuel factors approved by the Commission in its August 9, 2011, Order in Docket No. E-7, Sub 982, effective for service rendered on or after September 1, 2011, through August 31, 2012, are as follows:

	Residential	Commercial	Industrial
Fuel and Fuel-Related Costs ¢/kWh	2.3941	2.3931	2.3926
Experience Modification Factor (EMF) ¢/kWh	(0.0093)	(0.0215)	(0.0303)
EMF Interest Decrement ¢/kWh	(0.0012)	(0.0029)	(0.0040)
Total Fuel and Fuel-Related Costs Factor ¢/kWh	2.3836	2.3687	2.3583

The Stipulating Parties agree that the differential between the composite rate and rates by customer class shall be included in the rider components of the total fuel and fuel-related cost rate consistent with witness McManeus' supplemental testimony.

No party offered evidence opposing this provision of the Stipulation. The Commission finds and concludes that a base fuel and fuel-related factor of 2.3935 cents per kWh, excluding gross receipts tax and regulatory fee, is just and reasonable to all parties in light of all the evidence presented, for purposes of this proceeding. This factor, including the EMFs, results in the following fuel and fuel-related cost factors approved by the Commission in Docket No. E-7, Sub 982: 2.3836 cents per kWh for the Residential class; 2.3687 cents per kWh for the Commercial class; and 2.3583 cents per kWh for the Industrial class.

EVIDENCE SUPPORTING FINDINGS OF FACT AND CONCLUSIONS NOS. 16-17

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, Duke Energy Carolinas' verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Under the Stipulation, the terminating DSM deferral account balance rider of 0.0140 cents per kWh, excluding gross receipts tax and regulatory fee, which is scheduled to expire on December 31, 2012, will remain in effect as previously approved in Docket No. E-7, Sub 828, effective January 1, 2008. In addition, the Stipulation provides that the base rates approved in this proceeding will include (1) an increment amount for use in the annual proceeding to adjust the EDPR as approved in Docket No. E-7, Sub 828, effective January 1, 2008; and (2) decrement amounts of 0.0642 cents per kWh and 0.0067 cents per kWh (both excluding gross receipts tax and regulatory fee), for flowback of BPM Net Revenues and Non-Firm Point-to-Point Transmission Revenues, respectively, for purposes of measuring the continuing annual adjustment to the BPM True-Up Rider as previously approved in Docket

No. E-7, Sub 828, effective January 1, 2008. The Commission finds and concludes that these provisions of the Stipulation are just and reasonable to all parties in light of all the evidence presented. The Commission also finds that the increment amount related to the EDPR should be provided at the time the Company makes its compliance filing in this docket.

EVIDENCE SUPPORTING FINDINGS OF FACT AND CONCLUSIONS NOS. 18-19

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, Duke Energy Carolinas' verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

The Stipulation provides that each rate component for each rate schedule, including the Basic Facility Charges, shall be modified by an equal percentage to arrive at a 7.21% increase.

Company witness Bailey testified that the Company and the Public Staff have agreed to various rate design changes to effectuate the recommended 7.21% increase to all rate classes.[1] Witnesses at the public hearings testified regarding their severe distress at the prospect of a rate increase during the current time of widespread economic hardship. An equal percentage rate increase for all customer classes provides greater mitigation to the most vulnerable customers than would a strict cost of service-based rate design, and thus is justified in the present economic circumstances. Based on the testimony of witness Bailey, the concerns expressed by many of the public witnesses, and the agreement of the Stipulating Parties, the Commission finds and concludes that this allocation of the revenue increase among the rate classes as set forth in Paragraph 2.D. of the Stipulation is just and reasonable to all parties in light of all the evidence presented.[2]

Company witness Bailey testified that he believes that the agreed-upon rate design provisions contained in Paragraph 5 of the Stipulation represent a reasonable compromise of the issues in the context of the settlement. Witness Bailey and Public Staff witnesses Floyd and Lowdermilk testified in support of these rate design provisions.

In his pre-filed direct testimony, witness Bailey described the Company's proposed modifications to its Hourly Pricing Schedule (Schedule HP). Witness Lowdermilk testified in his direct testimony that the language of the revised Schedule HP was unclear and recommended changes, which were accepted by the Company in witness Bailey's rebuttal testimony. The Stipulation provides that the Company may implement its Schedule HP proposal, as set forth in witness Bailey's testimony, to revise the calculation of rationing charges and the criteria associated with adjustments to the Customer Baseline Demand. In addition, this provision of the Stipulation provides that the wording of Schedule HP shall be revised as recommended in Public Staff Witness Lowdermilk's Exhibit 2.

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[1] During cross-examination, witness Bailey explained that the 7.21% increase recommended in the present proceeding was separate from and in addition to the phase-in of charges that were approved in the Company's last general rate case in Docket No. E-7, Sub 909.

[2] The Commission previously has authorized rate changes in an equal amount across all customer classes. *See, e.g.,* Order Approving Fuel Charge Adjustment, issued November 14, 2008 in Docket No. E-2, Sub 929.

Witness Bailey in his direct testimony proposed a new transformation discount available only to new load in a new establishment receiving initial permanent service. The discount would be provided for qualifying customers who own the step-down transformation and all other facilities beyond the transformation which the Company would normally own. The Company proposes to make this discount available as a pilot program for a two-year period so that it can study customer preferences, how the discount may best be applied, and any potential system impacts. CUCA witness O'Donnell argued that not offering the discount to all customers would be discriminatory. Witness Bailey explained in his rebuttal that not offering the discount to all customers was not discriminatory as the Company has structured the offer as a pilot, which does not preclude a general progression toward more voltage differentiated rates that can be offered to more customers based on the Company's experience in the pilot.

Paragraph 5.D. of the Stipulation provides that the Company may implement its proposed Transformation Discount Pilot for a period of two years, as provided in the direct testimony of Company witness Bailey. The Stipulating Parties further agree that the Company should provide an annual report on the number of customers participating in the pilot, the rate schedule under which the customers are being served, and the aggregate demand served (kilowatts) associated with this pilot. Six months prior to the end of the pilot, the Company shall file a request to either continue and expand the pilot to all non-residential customers with qualifying loads, or to cancel the pilot.

With respect to the transitioning of customers served on Rate Schedule YL to Rate Schedule OL, Public Staff witness Lowdermilk testified that greater attention should be given to bringing Schedules YL and OL together. In his rebuttal testimony, witness Bailey testified that the Company is committed to developing a transition plan for these customers and presenting this plan in its next general rate case. Paragraph 5.F. of the Stipulation reflects this commitment by the Company.

In regard to cable television (CATV) power supply equipment, Time Warner witness Coughlin explained that cable television companies require thousands of small amplifier devices along the length of the cable system. These devices have the unusual characteristic of a 100% load factor, drawing the same power requirement at all times. Currently, these CATV power supplies are served by the Company under the Small General Service (SGS) rate. Witness Coughlin asserted that these devices are being billed unfairly under existing rates because they are paying for all energy at the highest possible level, even though they cost less to serve. In his rebuttal testimony, Company witness Bailey acknowledged that a rate recognizing the load factor characteristics of CATV power supplies was reasonable. He proposed a separate rate provision under Rate SGS that would apply to CATV power supply equipment. Service under the rate would be charged the SGS Basic Facilities Charge, but billed a flat rate for all usage of approximately 5.5 cents/kWh. The amendment to Paragraph 5.G. of the Stipulation, agreed to by Time Warner, adopts this proposal on a pilot basis.

Paragraph 5.H. provides that the Stipulating Parties recognize that as a result of changes to rate schedules, it is anticipated that customers will migrate to different rate schedules. The Stipulation provides that in the development of final rates, Duke Energy Carolinas shall calculate the expected lost revenue due to migrations and recover 50% of this amount from the classes of customers in which migration occurs. Pursuant to the Stipulation, the Public Staff retains the right to contest the reasonableness of the adjustment that the Company proposes to incorporate for expected lost revenue due to migrations and to request an evidentiary hearing for the purpose of resolving any such dispute.

Public Staff witness Floyd testified concerning the ongoing efforts by the Company, the Public Staff, and other interested parties to investigate how rate design can effectively and fairly promote greater energy efficiency. He stated that he has participated in several discussions and meetings regarding the development of new time-of-use rate structures and the design of those structures to send strong price signals to customers to reduce peak and energy consumption, particularly in the residential class. Witness Floyd noted that these discussions are ongoing. Paragraph 5.I. of the Stipulation requires continued work on this issue and reflects a commitment by the Stipulating Parties to find ways to promote energy efficiency through rate design.

Paragraph 5.J. of the Stipulation provides that the Stipulating Parties will continue to investigate the feasibility of dynamic pricing rate structures, including but not limited to critical peak pricing and time-of-use rate structures for both residential and non-residential customers, with the intent to include such dynamic pricing rate structures as a pilot program in the Company's next general rate case proceeding.

Based on the testimony of witnesses Bailey, O'Donnell, Coughlin, Lowdermilk, and Floyd, as well as the agreement of the Stipulating Parties, the Commission finds and concludes that the resolution of the rate design issues agreed upon in Paragraph 5 of the Stipulation, with the exception of the issue of OPT rates as discussed below, are just and reasonable to all parties in light of all the evidence presented.

EVIDENCE SUPPORTING FINDING OF FACT AND CONCLUSION NO. 20

The evidence supporting this finding of fact and conclusion is contained in the Stipulation, Duke Energy Carolinas' verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

With respect to the recombination of the OPT rate class, the Stipulating Parties agreed to delay the recombination of Rate Schedule OPT. Company witness Bailey testified that combining OPT-G and OPT-I during this proceeding would have significant impacts to OPT-I customers. He testified that rather than classify OPT customers by Standard Industrial Classification (SIC) code, it may be more appropriate to establish eligibility by the voltage level served. He stated that while the current structure of OPT should not continue in the long-term, all of the parties needed to work together to come up with some alternative. A phase-in would be preferable to mitigate the adverse impact on customers.

Public Staff witness Floyd testified that OPT-G and OPT-I do have some dissimilar characteristics. He stated that while there might be merit to combining Rate Schedule OPT, the Public Staff did not recommend doing so in this case. He stated that the Company has agreed to work with the Public Staff and other parties to reach a consensus on the issue.

CIGFUR III witness Phillips, representing industrial clients, argued that these rates should continue to remain separate. He contended that cost of service results indicate that there is a meaningful difference in the two schedules. Witness Phillips testified that Duke performed a Demand, Energy and Customer Cost Study that clearly shows that the unit costs for OPT-I customers are lower than the unit costs for OPT-G customers and that the peak and average method shows similar results.

Witnesses Higgins, Chriss, and Rosa, representing commercial clients, supported the recombination of Rates OPT-I and OPT-G. Kroger witness Higgins testified that differentiating customer rates based solely on whether the customer is classified as industrial or commercial is rate discrimination with no reasonable basis. He suggested "closing the gap" in reasonably-sized steps. His recommendation is to reduce the differential between OPT-I/OPT-H[1] and OPT-G by one-third in this proceeding as a first step toward combining these rates. Commercial Group witnesses Chriss and Rosa testified that OPT-G provides a cross-subsidy of approximately $25.7 million to OPT-I and that keeping the OPT-G and OPT-I rate schedules separate is inequitable because it would continue a discriminatory rate differential that has no cost basis.

While affirming his direct testimony, witness Bailey testified in his rebuttal testimony in response to these witnesses:

> In this case, however, I contend that significant impacts to industrial customers in recombining these rates would not be reasonable at this time. This is particularly true when considering the economic climate for industry and manufacturing in the country generally and in the Carolinas in particular. However, I believe the Company's previous stated positions and the arguments of the commercial groups should not be ignored, and meaningful, gradual progress should be made toward recombining the rates.
>
> I believe the reasonable guidepost of gradualism should be considered and I agree with Witness Higgins' recommendation that a phase-in of this recombination is reasonable and should be adopted by the Commission. In deference to the current economic climate, however, I recommend that this transition begin with the Company's next general rate proceeding.

(T. Vol. 4, pp. 245-46.)

Consistent with witness Bailey's recommendation, the Stipulation provides that OPT-G and OPT-I shall not be consolidated at this time, but that the Stipulating Parties agree to consider a three-step phase-in of the consolidation to be presented in the Company's next general rate case proceeding. That rate case proceeding is anticipated to commence later this year.

[1] The rates in Rate Schedule OPT-H are identical to those in Rate Schedule OPT-I.

The concept of "gradualism" in rate design has been applied repeatedly by this Commission and endorsed by the North Carolina Supreme Court. For example, in State ex rel. Utilities Comm'n. v. Carolina Utility Customers Ass'n, Inc., 314 N.C. 171, 195-96, 333 S.E.2d 259, 274-75 (1985), the North Carolina Supreme Court affirmed the Commission's order entered in the Company's 1984 general rate case, holding that it was appropriate for Duke Power to make a rate change gradually in order to avoid subjecting its customers to "rate shock." Similarly, in State ex rel. Utilities Comm'n. v. Eddleman, 320 N.C. 344, 358 S.E.2d 339 (1987), the Supreme Court affirmed the Commission's adoption of a Company proposal for phasing in a narrowing of the differential between rates of return among classes. Further, in its Order dated October 10, 1998, in Docket No. G-5, Sub 386, the Commission found that factors that must be considered in rate design in addition to cost of service include, among others, "the economic and political factors that are inherent in the ratemaking process, including the encouragement of expansion." 189 P.U.R. 4th 251, 259 (1998).[1]

The Commercial Group, in its Post-Hearing Brief, stated that the Commission should give no weight to the attempt to resolve the OPT dispute by stipulation. It is long-standing law in North Carolina that an agreement between two parties is not binding on non-parties and is unenforceable. Further, neither Duke nor the Public Staff take service under the OPT rate schedule and, therefore, neither has a material stake in resolving the OPT dispute.

In its Post-Hearing Brief, Kroger stated that Duke's practice of differentiating between certain customer rates based solely on whether or not the customer is classified as industrial or commercial is an unduly discriminatory basis for differentiating rates among customers. This practice violates G.S. 62-140 and state policy outlined in G.S. 62-2(a)(4), prohibiting discrimination. The Commission should begin to phase-in the consolidations of rate schedules OPT-I and OPT-G in this proceeding.

The Kroger Brief noted that the segregation of the OPT rates was first introduced in Docket No. E-7, Sub 828.[2] This was a departure from past Commission practice, which maintained a single rate for OPT customers. Duke's OPT-I rate schedule is now only available to customers whose establishments are classified as "Manufacturing Industries." Thus, commercial customers that are similarly situated to industrial customers taking service under OPT-I are precluded from rate schedule OPT-I merely because of their SIC code.

In its Post-Hearing Brief, the City of Durham argues that OPT-I should be revised to define the rate by electricity use characteristics and actual cost of service, rather than by SIC code. Local government facilities with a significant portion of off-peak load, including water and sewer treatment plants, should be able to access the OPT-I rate, which is lower than the OPT-G rate they now use. Such facilities would likely currently qualify for the OPT-I rate, except for the arbitrary use of SIC codes to define the rate's applicability.

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[1] The Commission's decision in this case was affirmed by the Supreme Court in State ex rel Utilities Comm'n. v. Carolina Utility Customers Ass'n, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000).

[2] Stipulation (Oct. 5, 2007).

The Commission has carefully considered the testimony of witnesses Bailey, Floyd, Phillips, Higgins, Chriss, and Rosa, as well as the post-hearing briefs of the parties. The Commission is concerned with the impact of increasing Schedule OPT-I and OPT-H rates. However, the Commission is also concerned with the reasonableness and fairness of maintaining a differential between Schedules OPT-I/OPT-H and Schedule OPT-G based largely on labels such as the SIC codes. Thus, the Commission concludes that steps toward potentially recombining the OPT-I, OPT-H and OPT-G rates in an equitable manner should begin now, and not be delayed for consideration at a later time, as proposed in the Stipulation. Therefore, the Commission finds and concludes that it is appropriate that the Company reduce the rate differential between the OPT-I/OPT-H and OPT-G rate schedules by one-third as part of this proceeding.

EVIDENCE SUPPORTING FINDING OF FACT AND CONCLUSION NO. 21

The evidence supporting this finding of fact and conclusion is contained in the Stipulation, Duke Energy Carolinas' verified Application and Form E-1, the testimony and exhibits of the witnesses. In its conclusion, the Commission also has relied on the arguments in the Post-Hearing Brief by City of Durham and the entire record in this proceeding.

According to the City of Durham in its Post-Hearing Brief, Schedule PL (public lighting) should be reopened, or the rates in Schedule GL (government lighting) should be the same as those in Schedule PL, and not be aligned with the private use rates of Schedule OL (outdoor lighting). Duke Energy Carolinas instituted rate GL in January 2010, and closed the existing rate PL to any new poles or lights. Durham maintained that Schedule GL will be an accelerating burden if the rate increases proposed are allowed. Durham argued that it joined with the Public Staff two years ago to oppose the closing of Schedule PL and creation of the new Schedule GL. Durham maintained that, as new poles and lights are added, the impact of the new GL rates becomes more burdensome. Duke Energy Carolinas has stated its intention to keep increasing street lighting's rates under Schedule GL until they are the same as the private party OL rates. Durham maintains this is inappropriate and does not account for important cost factors that differentiate public street lighting from private outdoor lighting.

Further, Durham asserts that Duke Energy Carolinas' rate schedules should show the up-front capital cost of poles and wiring. The Commission ordered Duke Energy Carolinas two years ago to allow public lighting customers to pay the capital costs of poles and wiring up front, rather than paying a continuing monthly fee for these capital costs for the entire life of the light. Durham noted, however, that the PL and GL rate schedules continue to only list per month costs for poles and wiring. For a locality to budget project costs effectively or charge developers of new streets for the lighting costs, the locality needs to know the costs of street lighting poles and wiring.

In addition, Durham submits that Duke Energy Carolinas should charge only for street lighting that is actually providing light. Durham continues its request that Duke Energy Carolinas be required to perform regular inspection and maintenance of street lighting as a part of the service, without requiring outage reporting by the customer or additional charges for such service. Durham maintains that localities which buy street lighting from Duke Energy Carolinas pay monthly fees for a significant percentage of street lighting which is out of service and from which the public receives no benefit.

Further, Durham submitted that Duke Energy Carolinas should be required to make it easier to report outages. According to Durham, at this time Duke Energy Carolinas requires telephone, fax or computer reporting and tying a ribbon around the pole. The ribbon tying requirement is time-consuming and problematic. At a minimum, Duke Energy Carolinas should accept GIS data electronically, which would simplify the reporting of outages for the locality and is technically very feasible. Although Duke Energy Carolinas offers an outage reporting technology, the charge is expensive, $2.50 per light per month. Durham asserted that with the rate increases Duke Energy Carolinas has received in recent years, identifying and repairing street light outages is a service that should be provided without extra charge.

The Commission's official file also contains letters expressing support for the positions advocated by Durham in this docket from the North Carolina League of Municipalities (specifically supporting two of Durham's issues), Town of Butner, Town of Chapel Hill, City of Conover, Town of Cornelius, Town of Franklin, City of Hickory, City of Marion, Town of Matthews, Town of Mount Pleasant and Town of Wilkesboro (collectively, municipalities).

The Commission notes that current Schedule GL does show that the customer may, at its option, prepay the initial capital cost of poles and underground wiring, in which case the monthly rate per luminaire shall be the Existing Pole Rate as shown. The Commission finds that Duke Energy Carolinas cannot reasonably be expected to list current charges for such capital costs, as these would continually change.

The City of Durham did not file testimony in this proceeding. Therefore, the record is devoid of evidence supporting most of Durham's assertions, such as the number and frequency of street light outages and the magnitude of the cost to Durham of street lights that are not in service. Nevertheless, the Commission is concerned about the matters raised in Durham's Post-hearing Brief and desires to create a means by which Duke, the Public Staff, Durham and other Duke Energy Carolinas' municipal customers can seek to resolve these concerns. Therefore, the Commission finds good cause to order that Duke Energy Carolinas and the Public Staff should meet with the City of Durham, and representatives of other interested Duke Energy Carolinas' municipal customers, to discuss the fairness of the rates in Schedule GL, the Company's procedures for detection, reporting and repair of malfunctioning street lighting, and related issues in an attempt to resolve these issues, if possible, before the Company's next general rate case proceeding.

EVIDENCE SUPPORTING FINDING OF FACT AND CONCLUSION NO. 22

The evidence supporting this finding of fact and conclusion is contained in the Stipulation, Duke Energy Carolinas' verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Company witness Carter provided testimony regarding the Company's performance with regard to customer service. He testified that both the Company's 2009 rate increase and the recession led to increases in customer bill inquiries, payment issues, and communication challenges. As a result, the Company increased its customer service efforts and widened the focus of these efforts. He testified that in 2010, the Company's Southeast call center handled 20% more calls than in 2008, many of them more complex inquiries than the Company has seen in the past. In response, the Company has added approximately 40 employees to respond to the increase in customer calls and has improved the continuous coaching of its customer service representatives to improve their ability to provide information and problem resolution when customers call. The Company also enhanced its ability to communicate timely outage information to customers by increasing call-in reporting capability and launching a web page to indicate the general location of outages, as well as providing this information through Facebook and Twitter. He also testified that the Company is included in the annual residential and midsize business studies of J.D. Power and Associates and continually rates very highly, and also rates very highly in similar surveys for large business customers.

Company witness Jamil provided testimony regarding Duke Energy Carolinas' operational performance during the test year. He testified that the Company's nuclear fleet continued to perform well, ending the test period with especially good performance. The Company's seven nuclear units operated at a system average capacity factor of 95.88% for the test period, which is the highest nuclear capacity factor in Company history. The Oconee nuclear station set the highest capacity factor in station history and other individual units also set records for the period. In addition, Catawba Unit 2 concluded a 517 day breaker-to-breaker run when it began a refueling outage in September 2010. This accomplishment followed breaker-to-breaker runs of 485 days and 497 days at McGuire Unit 1 and Oconee Unit 2, respectively, prior to the spring 2010 refueling outages.

Company witness Jamil also testified that the system average nuclear capacity factor has been above 90% for eleven consecutive years. The achieved test period system nuclear capacity factor of 95.88% reflects four refueling outages and exceeds the average capacity factor of 91.2% for all U.S. nuclear plants in 2010. In particular, shorter refueling outages and improved forced outage rates have contributed to increasing capacity factors achieved by the Company's nuclear fleet. He also testified that the system average capacity factor of 95.88% was more than 2% above the Company's 2010 targeted performance. He stated that the cost impact modeled analysis indicates that a 2% increase in nuclear capacity factor results in annual fuel savings of at least $30 million for the Company's customers.

Witness Jamil also testified that the Company's fossil generating system operated efficiently and reliably during the test period. He stated that two key measures are used to evaluate the operational performance of generating facilities: (1) equivalent availability factor, and (2) capacity factor. Equivalent availability factor refers to the percent of a given time period a facility was available to operate at full power. Capacity factor measures the generation a facility actually produces against the amount of generation that theoretically could be produced, based upon its maximum dependable capacity. The Company's seven base load coal-fired units achieved results of 84.2% equivalent availability factor and 70.5% capacity factor over the test period. During the peak summer season within the test period (May through August), these base load units achieved results of 84.7% equivalent availability factor and 76.8% capacity factor. The Company's thirteen intermediate coal-fired units achieved results of 91.2% equivalent availability factor and 46.6% capacity factor over the test period, and performed similarly during the summer peak months at 92.7% equivalent availability and 60.9% capacity. The ten peaking coal-fired units achieved results of 85.4% equivalent availability factor and 14.7% capacity factor for the test period, and also performed similarly during the summer peak months with 84.5% equivalent availability and 27.3% capacity. The Company's combustion turbines were available as needed in this time period, with a 99.3% starting reliability result for the large combustion turbines at the Lincoln, Mill Creek, and Rockingham stations. Witness Jamil also testified that the Company's hydroelectric fleet had a weighted availability factor of 90.3%, which is higher than the most recently published NERC average of 85.3% for the period 2005-2009 representing more than 1000 North American hydro units.

Company witness Stanley provided testimony regarding the performance of Duke Energy Carolinas' transmission and distribution system. He explained that the System Average Interruption Frequency Index (SAIFI) is a ratio that demonstrates the average number of interruptions greater than five minutes in length per customer during the course of the year. He also explained that the System Average Interruption Duration Index (SAIDI) is the average number of minutes each customer is interrupted per year, and is expressed by the sum of customer interruption durations divided by the total number of customers served. He testified that the overall trend of the Company's SAIFI and SAIDI scores shows a steady improvement in the Company's performance.

Public Staff witness Lowdermilk testified that he reviewed various types of outage data for the most recent calendar year, as well as historical trends, to assess the Company's overall quality of service. In addition, he testified that he meets annually with Duke Energy Carolinas' representatives to review and discuss the Company's efforts in the areas of safety, reliability, and customer service, as well as working closely with the Public Staff's Consumer Services Division on service-related customer complaints. He testified that he believes Duke Energy Carolinas' overall quality of service is adequate.

Witnesses Carter, Jamil, and Stanley demonstrated that Duke Energy Carolinas has performed well in the areas of customer satisfaction and reliability during the test period. No intervenor not a party to the Stipulation offered any evidence contradicting the agreement of the Stipulating Parties that the quality of Duke Energy Carolinas' service is good. The results of the Company's operation of its generation fleet are indicative of solid performance, and good operation and management of the Company's generation fleet during the test period. There were relatively few service-related customer complaints at the public hearings, and the Company is expected to promptly follow up and resolve those complaints. On the whole, consistent with the testimony of the witnesses and Paragraph 8 of the Stipulation, the Commission finds and concludes that the overall quality of electric service provided by Duke Energy Carolinas is good.

EVIDENCE SUPPORTING FINDING OF FACT AND CONCLUSION NO. 23

The evidence supporting this finding of fact and conclusion is contained in the Stipulation, Duke Energy Carolinas' verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Company witness Carter testified that the Company has responded to the national economic crisis by broadening the safety net for some of its most vulnerable customers in the Carolinas whom it knows are struggling to pay their electric bills. As a result, in pre-filed testimony the Company committed to contribute $7 million of additional funding to be paid by the Company's shareholders to help ease the financial burden of the Company's low-income customers in North Carolina. Witness Carter testified that the Company planned to disburse these funds to agencies that can provide help to its North Carolina customers in managing and paying their electric bill, and would work with the Public Staff to determine the appropriate disbursement of those funds.

Company witness Carter testified at the evidentiary hearing that as a result of the Stipulation between the Company and the Public Staff, the Company has committed to a one-time $11 million contribution of shareholder funds to aid its low-income customers. This represents a significant increase over the Company's earlier proposal for $7 million of low-income assistance. Witness Carter explained how the Company intentionally arrived at the $11 million figure in order to mitigate the rate increase for all of its low-income customers who fall below the federal poverty guidelines. He testified that the Company arrived at the decision to aid its low-income customers after listening to the testimony at the public hearings throughout the State. Additionally, NC WARN, et al., witness Colton acknowledged that the Commission does not have the authority to order Duke Energy's shareholders to make such a contribution in the absence of a settlement such as the one the Company has entered into with the Public Staff.

No party offered any evidence opposing the agreement of the Stipulating Parties that Duke Energy Carolinas contribute $11 million of shareholder dollars to assistance for its low-income customers. Therefore, consistent with Paragraph 9.A. of the Stipulation, the Commission finds and concludes that the Company's plan to make a one-time $11 million shareholder contribution to assistance for its low-income customers in connection with its rate increase request is just and reasonable to all parties and an appropriate means to help mitigate the impact of the Company's proposed rate increase on its most vulnerable customers.

EVIDENCE SUPPORTING FINDING OF FACT AND CONCLUSION NO. 24

The evidence supporting this finding of fact and conclusion is contained in the Stipulation, Duke Energy Carolinas' verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

As described in Public Staff witness Lucas' testimony, the General Assembly, in S.L. 2009-451, Sec. 9.14, directed the University of North Carolina (UNC) to contract with a third party to build and operate up to three demonstration wind turbines in the sounds or off the coast of North Carolina (Project). The legislation exempted the Project from a number of permitting requirements, including a certificate of public convenience and necessity under N.C. Gen. Stat. 62-110.1, and authorized any public utility that owned the Project to seek approval from the Commission for a rider to recover its just and reasonable costs upon completion, including a return on the costs. In July 2010, this legislation was amended by S.L. 2010-31, Sec. 9.14 to, among other things, provide for the recovery of related capital costs and the interest on funds used during construction if the utility abandoned construction of the Project. Under the legislation, the utility bears the burden of proving that the decision to abandon construction of the Project was prudent. This legislation is hereafter referred to as the “Coastal Wind Legislation”.

On September 9, 2009, UNC and Duke Energy Carolinas entered into a contract for the Project. The Company acted as the general contractor and had sole responsibility for the Project management, including oversight of the environmental permitting, engineering, legal, and financial aspects of the Project. Duke Energy Carolinas also contracted with third parties to assist with the Project. The Company terminated the Project in August 2010. Duke witness McManeus testified that the Project cost of $3.7 million includes labor and labor-related costs, consulting services and various research studies. In addition, the amount includes $0.5 million in carrying costs.

Duke Energy Carolinas requested a rider of 0.0070¢ per kWh based upon a total cost of $3,733,761 and adjusted North Carolina retail sales of 54,802,422,000 kWh. Public Staff witness Lucas testified that the Company should have terminated the project in March 2010, when it was already apparent that the updated cost estimates substantially exceeded the original estimate of $35 million. Witness Lucas asserted that as Duke Energy Carolinas did not terminate the Project until August 2010, the portion of the costs incurred and paid after March 2010, totaling $2,372,157, should not be recovered from Duke Energy Carolinas’ customers. Company witness Svrcek testified that he disagreed with witness Lucas and submitted that it was reasonable and prudent for the Company to both continue the development of the Project beyond March 2010 and cancel the Project in August 2010.

The Stipulating Parties agree that for purposes of the settlement the Company’s rider should include only the recovery of all costs incurred for work performed prior to the end of March 2010. Company witnesses Svrcek and Shrum testified that based upon the terms of the Stipulation, the requested recovery amount has been adjusted and no further requests will be made for recovery of the costs incurred after March 2010.

NCSEA contends that Duke has not met its burden of proof and should not recover any costs of the Project. NCSEA cites N.C. Sess. Law 2010-31, Sec. 9.9, which states in pertinent part:

> [S]hould the demonstration wind turbines be abandoned prior to completion, the capital costs and AFUDC related to the project, less any salvage value received, shall nonetheless be recoverable provided that the utility shall bear the burden of proving by a preponderance of the evidence that the decision to abandon construction of the project was prudent.

NCSEA submits that Duke did not present evidence of the Project's capital costs and AFUDC. In addition, Duke did not present evidence of salvage value or lack of salvage value. NCSEA asserts that Duke's evidence showed direct purchases in the amount of approximately $250,000, and that Duke incurred over $2.5 million in labor, contract and consulting costs. Therefore, Duke should not recover any amount for the abandoned Project.

CUCA witness O'Donnell proposed that the Project costs should be recovered through a Renewable Energy and Energy Efficiency Portfolio Standard (REPS) rider.

The Coastal Wind Legislation provides for its own rider. The Commission finds and concludes that it is reasonable to establish the Coastal Wind Demonstration Project Rider in the present proceeding for purposes of administrative convenience, even though the Rider is not part of the base rates that are the subject of this general rate case.

The Commission finds and concludes that Duke has met its burden of proof on this issue. The $3.7 million costs incurred by Duke for labor and labor-related costs, consulting services and various research studies are capital costs, and the $0.5 million carrying costs are AFUDC, within the meaning of N.C. Sess. Law 2010-31, Sec. 9.9. In addition, based upon the intrinsic nature of labor and labor-related costs, consulting services, research studies and carrying costs, as well as the fact that the Project was abandoned, these costs did not result in assets or material which has salvage value.

The Commission finds and concludes that pursuant to the Stipulation, the amount to be recovered through the Coastal Wind Demonstration Project Rider will be based on Duke Energy Carolinas' calculation of costs incurred through the end of March 2010, which is $1,191,696, plus a return at the weighted average cost of capital approved in this Order, totaling $1,396,232. All issues with respect to the Coastal Wind Demonstration Project Rider are resolved by the Stipulation and no further requests may be made for recovery of any other costs related to the Project. This rider shall be in effect for the 12-month period beginning the effective date of the base rates approved in this Order.

The Commission finds and concludes that the provisions of the Stipulation pertaining to the Company's recovery of its capital costs and AFUDC for the Project are just and reasonable to all parties in light of the evidence presented

EVIDENCE SUPPORTING FINDING OF FACT AND CONCLUSION NO. 25

The evidence supporting this finding of fact and conclusion is contained in the Stipulation, Duke Energy Carolinas' verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Public Staff witness Lowdermilk testified that the Public Staff has concerns regarding Duke Energy Carolinas' vegetation management practices and procedures. According to witness Lowdermilk, the Public Staff had received complaints about the Company's vegetation management during 2011. These complaints generally concerned: (1) the removal of trees that customers did not want removed within the power line right-of-way (ROW); (2) the failure to remove trees in the ROW that are interfering with power lines and contributing to customer power outages; and (3) the cutting or trimming of trees and leaving debris on the customers' premises. Witness Lowdermilk was also concerned that Duke Energy Carolinas' vegetation management practices and procedures were not well-defined and publicly available. He noted that the Commission had recently found the vegetation management practices of Progress Energy Carolinas (PEC) to be unclear and, as a result, directed PEC to develop and file with the

Commission a comprehensive, consistent, and publicly-available vegetation management policy. He recommended that the Commission direct Duke Energy Carolinas to do the same within 90 days of Commission's order in this proceeding.

In her rebuttal testimony, Company witness Yarbrough addressed witness Lowdermilk's concerns. She noted that the Company employs a vegetation management process that is aimed at cost-effectively minimizing service interruptions. Witness Yarbrough also explained that the Company communicates information about its vegetation management practices and procedures through its website.

In the Stipulation, the Company agrees to the review of its vegetation management policy and procedures and filing of same with the Commission, as recommended by Public Staff witness Lowdermilk. According to the Stipulation, within 90 days of the Order in this proceeding, the Company will review its vegetation management policies and procedures, develop a clear, comprehensive, consistent, and publicly-available policy description, file it with the Commission, and publish it on the website in a publicly-available manner. The Company and the Public Staff agree to hold further discussions to effectuate these commitments.

Based on the testimony of witnesses, as well as the agreement of the Stipulating Parties, the Commission finds and concludes that the provisions found in Paragraph 9.F. of the Stipulation pertaining to the Company's vegetation management policies and procedures are just and reasonable to all parties in light of the evidence presented, subject to the following modifications adopted by the Commission.

The Commission directs that Duke Energy Carolinas shall within 90 days of the date of this Order, and before publishing any changes to its vegetation management policies on the Company's website or in any other manner, provide the Commission with information regarding the Company's vegetation management policies. The information shall be filed by Duke Energy Carolinas in a new docket and shall include the following:

(1) A pleading in compliance with the Commission's requirements identifying with particularity the complete set of documents comprising Duke Energy Carolinas' vegetation management policies and practices, and, if not attached to the pleading, where the documents can be accessed electronically;

(2) A statement or statements providing any justification that Duke Energy Carolinas has developed for the policies and practices that it has adopted to implement vegetation management;

(3) Duke Energy Carolinas' representations and justifications therefore with respect to its conclusions as to whether its vegetation management procedures and practices comprise a comprehensive, consistent and publicly-available vegetation management policy that enables the Commission, landowners and Duke Energy Carolinas' employees and contractors to discern what the Company's transmission and distribution vegetation management policies are, how those policies are implemented, and where landowners or others interested in the Company's

transmission and distribution vegetation management policies and practices should go to discuss them;

(4) A definitive explanation as to whether vegetation growing within transmission and distribution rights-of-way with a height in excess of 15 feet at maturity will be removed and, if so, by whom; or conversely, whether such vegetation can be topped or trimmed and, if so, by whom; and where within the vegetation management documentation this is addressed;

(5) Identification of the Duke Energy Carolinas' personnel responsible for the Company's vegetation management policies and practices, and identification of those Duke Energy Carolinas' personnel responsible for responding to the Commission's Orders in the new vegetation management docket; and

(6) A detailed statement, including the proposed text, of how Duke Energy Carolinas intends to make the information about its vegetation management policies and practices available to the public.

EVIDENCE SUPPORTING FINDINGS OF FACT AND CONCLUSIONS NOS. 26-30

The evidence supporting these findings of fact and conclusions is contained in Duke Energy Carolinas' verified Application and Form E-1, the testimony and exhibits of the witnesses, the Stipulation and the entire record in this proceeding.

Buck and Bridgewater Plants

Public Staff witness Peedin testified that the Public Staff is still evaluating an adjustment to non-fuel variable O&M expenses to reflect the change in Duke Energy Carolinas' generation mix attributable to the addition of the new Buck and Bridgewater facilities. In her prefiled rebuttal testimony, Company witness Shrum testified that the Public Staff and Company have agreed that the parties will address this issue in the Company's deferral petition related to those facilities. In particular, in the event that (1) the Commission ultimately does not allow a deferral and (2) the incremental non-fuel production O&M expense impact of adding the facilities to the generation portfolio (including credits for the non-fuel expenses of other supply resources avoided as a result of the facilities being added to the generation mix) is expected to produce a net benefit to the customers between the time of the current case and Duke Energy Carolinas' next general rate case, the parties have agreed to recommend to the Commission that the return of such net benefit with interest should be effectuated through an alternative vehicle, such as an existing or new rider.

In Paragraph 9.B. of the Stipulation, the Stipulating Parties agreed to the positions set out in the pre-filed rebuttal testimony of Company witness Shrum, as stated above, regarding possible accounting changes for the generating mix of the Buck and Bridgewater Plants. The Public Staff reserves the right to challenge any deferral application the Company files to recover costs for new plant at the Buck and Bridgewater facilities.

Outside Services

Public Staff witness Peedin testified that the Public Staff is concerned that there may be a systematic problem with costs for outside services being improperly charged to Duke Energy Carolinas' North Carolina retail operations. Accordingly, witness Peedin recommended that the Commission order Duke Energy Carolinas to conduct a review of Account 923, outside services, for the 12 months ended December 31, 2011, and file a verified report of its investigation by April 30, 2012.

Company witness Shrum stated in her rebuttal testimony that the Company agrees to conduct such a review, but needs more time than proposed by Public Staff witness Peedin. Accordingly, the Company proposed to have the report available by July 1, 2012.

Paragraph 9.E. of the Stipulation provides that the Company will review outside services for the 2011 calendar year to investigate whether any costs have been improperly charged to North Carolina retail operations and will propose safeguards to prevent the charging of outside services to accounts other than Account 923, per recommendation of Public Staff witness Peedin and agreement by Company witness Shrum. Duke Energy Carolinas stipulated that it will file a verified report on its review by July 1, 2012. In addition, the Company has also agreed, pursuant to Paragraph 9.I. of the Stipulation, to provide the Public Staff with a list of all outside services charges to Duke Energy Carolinas not included in the North Carolina Supplemental Financial Reports information, whether the services were obtained directly or through a service company. The Company shall provide this information at the time of its annual filings of all future North Carolina Supplemental Financial Reports provided with Duke Energy Carolinas' FERC Form 1.

Stopped Meters

Public Staff witness Lowdermilk expressed concern in his pre-filed direct testimony that the Company had a higher than average incidence of stopped meters, and that Duke Energy Carolinas has a practice of back billing for extended periods of underbilled usage as a result of the stopped meters without taking proactive measures to prevent the accumulation of significant charges.

To address the stopped meter issue raised by witness Lowdermilk, the Company agrees in Paragraph 9.G. of the Stipulation to send a letter to customers after four months of no usage, except for customers on Schedules SGS and LGS utilizing the annual minimum billing options and customers that the Company identifies as seasonal customers. The Company agrees to work with the Public Staff as to the content of the letter. The Stipulation provides that the Company will implement this procedure within 120 days of the date of this Order and will report to the Public Staff and Commission upon implementation. The Company will meet with the Public Staff within six months of implementation and within a year after implementation will file a formal report to the Commission that contains the following: (1) the number of stopped meter customer letters mailed, (2) the number of customer responses received, (3) the number of stopped meters discovered as a result of the customer contact, (4) the number of months back billed for each stopped meter discovered, and (5) the amount of the back billing for each meter.

Cost of Service Reconciliation

The Company has also agreed, pursuant to Paragraph 9.H. of the Stipulation, to provide the Public Staff with (1) a detailed reconciliation of the per books amounts in its accounting records to the Cost of Service Study, showing which accounts and amounts are included in each line item of the Cost of Service Study, and (2) all work papers supporting any allocations not shown in the filed Cost of Service Study. The Company shall provide this information by the filing date of its next general rate case.

These provisions of the Stipulation were not opposed by any parties. The Commission finds and concludes that these provisions of the Stipulation are just and reasonable to all parties in light of the evidence presented.

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

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, Duke Energy Carolinas' verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Late Payment Charge

NC WARN, et al., witness Colton testified that Duke Energy Carolinas' late payment charge was unreasonable and should be modified. Referring to Duke Energy Carolinas' response to an NC WARN, et al., data request, witness Colton testified that the Company relied upon a 1975 statement from the Commission encouraging utilities to impose a 1% charge for late payment. According to witness Colton, the Company's late payment charge does not comply with Commission Rule R12-9, citing the portion of the rule that states "[t]his Commission recognizes, however that there are interest, finance, or service costs directly attributable to customers who excessively delay payment of utility bills, and considers that it is appropriate for a utility to attempt to recoup a portion of those costs by applying such interest, finance or service charges as may be reasonable and lawful." Witness Colton interpreted this portion of the rule to provide that interest, finance, or service costs recovered through a late charge must be directly attributable to customers who excessively delay payment of their utility bills and that the charge must be structured to recoup a portion of those costs. He disputed that Duke Energy Carolinas needed the late fee to recover collection costs. Witness Colton further disputed that Duke Energy Carolinas required the late fee to pay carrying costs on unpaid bills, arguing that the Company's charge of 1% of a bill balance can result in overpayment to the Company. Thus, witness Colton concluded, Duke Energy Carolinas' late fee is not designed to recover a portion of the costs caused by late payment of bills.

Witness Colton further maintained that the Company's late fee imposed adverse impacts on low-income customers based on his review of the Company's Equalized Payment Plan (EPP). He testified that customers who participate in the EPP are exempted from an assessment of charges to compensate for carrying costs, so long as those customers remain current on their scheduled payments. According to witness Colton, because Duke Energy Carolinas does not allow customers with an unsatisfactory payment record to participate in the EPP, the EPP tends to exclude low-income customers because they are more likely to be payment troubled.

Witness Colton concluded by making several recommendations to the Commission concerning its oversight of Duke Energy Carolinas' late fee. First, he recommended that the Commission exempt the Company's low-income customers from imposition of the late payment charge and require that low-income status be established by certification of income by an agency having responsibility for doing income verification or by presentation of verification by a customer that the customer's household participates in a public assistance program. Second, he recommended that Duke Energy Carolinas' late payment charge be imposed only on arrears in excess of 60 days. Third, witness Colton recommended that accounts on which no collection action is being taken be exempt from late payment fees, and fourth, he recommended that the Commission approve a late payment charge for Duke Energy Carolinas at a level of no more than either its weighted cost of capital or the Internal Revenue Service rate of interest on unpaid taxes. At the evidentiary hearing, witness Colton amended his recommendations to include requests for initiation of rulemaking dockets to consider several of his recommendations.

Company witness Yarbrough testified in rebuttal to witness Colton's assertions regarding the Company's late fee. She explained that Duke Energy Carolina's policy was consistent with Commission Rule R12-9(a), which has been in place for almost 40 years. Bills are due and payable upon receipt, and the Company does not apply any additional finance or penalty charge until 25 days after the date of the bill. Consequently, the Company can incur a delay of up to 60 days from the time customers use the service until it assesses a late payment charge. Moreover, contrary to witness Colton's assertions, the Company incurs collection expenses when imposing a late fee. For example, if a customer does not make a full payment, the Company's second bill to that customer must detail the prior account balance, and the Company must have systems in place to determine what portion of the total bill is past due or subject to a late payment charge. The Company must then provide for a reminder notice to be placed on past due bills in accordance with Commission rules. Commission Rule R12-11(f) requires that the Company issue a notice of disconnection at least ten days in advance of disconnection. The Company generally tries to put that notice on the second bill to give customers as much notice as possible and to allow them time to seek agency assistance or to enter into a deferred payment agreement (DPA).

Witness Yarbrough also discussed the Company's communications with customers on late payments and disconnection notices. She noted that during the period between the first notice of past due bill and the date payment is required, the Company often fields calls from customers requesting information on, among other things, DPAs. Customers may request DPAs through the Company's automated voice system or they may speak to a Company representative. The Company must also, in accordance with Commission Rule R12-11, provide a further notice at least 24 hours in advance of a disconnection. At that time, the Company attempts to contact customers by telephone as well as by mailed notice. The Company provides additional telephone notifications to customers with a medical alert on their account. If a customer enters into a DPA for more than five days, the Company will generally mail a copy of the DPA to the customer and then send a reminder notice before each payment is due. Even with these communications, the

Company's customer service representatives still field additional calls regarding DPAs and requests to modify DPAs.

Witness Yarbrough stated that if the Company has taken all of these steps, and the customer has still failed to pay, the Company must have systems in place to disconnect service. Furthermore, these steps do not account for the costs of the several payment options available to customers to stop disconnections as soon as they make a payment on the on-line assistance agency internet portal that the Company developed and maintains. The Company staffs that portal with a specialized team of customer service representatives who work closely with local assistance agencies and their clients. All of these actions have a cost.

Witness Yarbrough also refuted witness Colton's claims that the Company's late payment fee did not serve as an incentive to low-income customers to pay their bills on time by highlighting that approximately 71% of the Company's customers pay on time. She further disputed witness Colton's assertions regarding the EPP as evidence that the Company adversely impacts low-income customers with its late fee. As witness Yarbrough explained, the EPP's objective is to even out bill fluctuations by having the customer pay a levelized amount each month that exceeds the actual bill in some months and is less than the actual bill in other months; interest is neither charged nor paid on the balance. The plan was not designed for customers who have difficulty paying even a levelized amount for their electric service.

Commission Rule R12-9, entitled Uniform Billing Procedure, governs the imposition of a late payment charge for all utilities, and provides that "there are interest, finance, or service costs directly attributable to customers who excessively delay payment of utility bills," and that the Commission "considers that it is appropriate for a utility to attempt to recoup a portion of those costs by applying such interest, finance or service charges as may be reasonable and lawful." Commission Rule R12-9(d) provides that no utility shall apply a late payment, interest, or finance charge to the balance in arrears at the rate of more than 1% per month. It further provides that "[a]ll utilities which are required to file tariffs and which apply an interest, finance, or service charge must file tariffs to that effect" and that "[a]ll utilities must apply the appropriate interest, finance, or service charge on a uniform basis."

NC WARN, et al., has not met its burden to prove that the Company's late fee charges and practices are illegal or unreasonable. Based on the testimony of Company witness Yarbrough, the Commission finds and concludes that the Company's late payment charges are reasonable, lawful and in compliance with Commission Rule R12-9. As described by witness Yarbrough, the Company incurs costs from its collection activities, and it recovers a portion of those costs through its 1% late payment charge.

Further, the Commission declines to accept witness Colton's recommendations with respect to the Company's late fee. His recommendations are outside of the provisions of Commission Rule R12-9 in that they would apply to Duke Energy Carolinas alone instead of all the utilities, would carve out an exception to the rule for low-income customers where none currently exists, and would create a new methodology for determining the Company's late payment charge based on factors not referenced in Rule R12-9. Accordingly, the Commission finds and concludes that the Company's late fees are just and reasonable and in accordance with Commission rules.

Disconnection Notices

Witness Colton asserted that the Company's residential disconnection notices constitute a false and deceptive credit and collection practice. He made two recommendations with respect to the disconnection notices. First, he contended that Duke Energy Carolinas should be prohibited from issuing false and deceptive shutoff notices. Second, he stated that the Commission should order Duke Energy Carolinas "to fund an Earned Income Tax Credit (EITC) Initiative, funded at $500,000 a year for six years," as a penalty for its allegedly false and deceptive practices.

Witness Colton stated that Duke Energy Carolinas' disconnect notices are false and deceptive because he believes that the Company issues disconnect notices to customers with no true intention to actually disconnect them. In particular, he alleges that Duke Energy Carolinas does not intend to follow through with two "threats of action" contained in the disconnect notice: (1) that service will be disconnected if payment is not received, and (2) that a reconnection fee to restore service will be imposed on the disconnected customer, which the customer must pay. For example, witness Colton testified that in the twelve months ending July 2011, 5,066,092 disconnection notices were sent, but disconnection occurred only 142,827 times, for "a ratio of 35½ notices for each disconnection 'in fact taken.'"

Company witness Yarbrough provided rebuttal testimony in response to witness Colton's testimony regarding disconnection notices. She testified that after receiving a disconnect notice, most customers simply pay the bill, and many customers ask for and enter into a DPA with the Company. If the customer pays the required amount or enters into a DPA, the Company stops the disconnection. According to witness Yarbrough, through the third quarter of 2011 alone, the Company has made approximately 214,000 DPAs with North Carolina customers.

She testified that the decision to disconnect customers is governed by Commission Rule R12-11, and is a careful process that requires multiple notices. She explained that in order to help customers maintain electric service, the Company takes the welfare of its customers into account when making disconnection decisions, and complies with, and in some cases exceeds, the Commission's requirements. Additionally, the Company has a policy of suspending disconnection to all customers during periods of extreme temperatures.

Further, Commission Rule R12-11(r) provides as follows:

> Nothing in this rule shall preclude an electric utility from exercising reasonable discretion in waiving or extending the times provided herein pertaining to termination of service, particularly when such waiver or extension would result in the prevention of undue hardship in those cases where termination of service would be especially dangerous to health or where the customer or a member of the customer's household is elderly or handicapped.

Witness Yarbrough testified that, ultimately, the Company's goal is to supply electricity to its customers. She added that although disconnections and the threat of disconnections are necessary at times to address situations where customers do not pay their electric bill, the Company tries to work with its customers and come to a reasonable resolution of the issues where possible without disconnecting them.

NC WARN, et al., has not met its burden to prove that the Company's disconnection notices and practices are illegal or unreasonable. The Commission finds and concludes that the Company's disconnection notices and practices are neither false nor deceptive and are in compliance with Commission rules. In particular, under Commission Rule R12-11(r), the Company's representatives have the authority to defer disconnection based on individual circumstances. Accordingly, the Commission declines to accept NC WARN, et al., witness Colton's recommendations with respect to the Company's disconnection notices and practices.

EVIDENCE SUPPORTING FINDING OF FACT AND CONCLUSION NO. 33

The evidence supporting this finding of fact and conclusion is contained in the testimony and exhibits of various public witnesses, the testimony of Company witness Barbara Yarbrough and the entire record in this proceeding.

A number of public witnesses appeared and testified during the public hearings held in Charlotte, Marion, Franklin, High Point, Durham, and Raleigh. Many of those witnesses presented testimony regarding quality of service issues or certain other matters that, in the Commission's view, warrant further review and consideration by Duke Energy Carolinas and the Commission. The names of those witnesses, along with a brief explanation of their concerns, are set forth below.

Charlotte

No public witness testified during the public hearing held in Charlotte regarding individual quality of service or other matters that warrant further review and consideration by Duke Energy Carolinas and the Commission in this docket.

Marion

(1) Elizabeth Lawly, 175 Pinewood Drive, Marion, North Carolina: She testified that: (a) power outages, lasting 1 to 3 days, and up to 4 days, occur after a wind storm or snow storm, and (b) the Company does not keep its rights-of-way clear which has resulted in power outages which lasted for several days.

On cross-examination at the November 29, 2011 evidentiary hearing, Company witness Yarbrough stated that she was unable to specifically respond to Ms. Lawly's complaints but would be happy to provide a response upon request.

(2) Sharon Bowman, 212 Shuford Road, Marion, North Carolina: She testified that: (a) power outages have occurred frequently; (b) power outages are lengthy in duration; and (c) monthly bill amounts are irregular.

On cross-examination at the November 29, 2011 evidentiary hearing, Company witness Yarbrough testified that she spoke with Ms. Bowman during the break at the public witness hearing held in Marion, North Carolina, on October 25, 2011. With respect to the irregular bills, witness Yarbrough stated she learned that Ms. Bowman lives in an older home, had electric heat installed, and her home does not have adequate insulation. Witness Yarbrough stated she encouraged Ms. Bowman to consider installing thermal improvements to her home which would lower her electric bills in the future. Witness Yarbrough further testified that after the October 25, 2011 hearing the Company has attempted on several occasions to talk with Ms. Bowman concerning the outages. Witness Yarbrough stated that the area in which Ms. Bowman lives is served by a fairly long circuit having a large area of exposure to the elements and that there have been a few tree-related outages, an outage related to routine maintenance, and another outage as a result of a vehicle accident. A message was left on Ms. Bowman's cell phone and a card was left on the door of her residence requesting that she contact Duke Energy Carolinas. As of November 29, 2011, Ms. Bowman had not contacted the Company.

Franklin

(1) F. P. Bodenheimer, Jr., 250 West Rogers Street, Franklin, North Carolina: He testified that the loss of electric availability and proper wattage had resulted in costs for his business that cannot be tolerated anymore.

(2) Susan Leveille, Dillsboro, North Carolina: She testified to her concern about the difficulty of understanding her electric bill, particularly with regard to the Renewable Energy Rider on an electric account with no usage.

(3) Joe Deddo, 1612 Panther Creek Road, Almond, North Carolina: He testified to concerns regarding: (a) a three-phase non-energized line in Bryson City, and (b) poles on his property that he believed were rotten, reported to the Company, but evidently not replaced. In response to questions by the Commission at the evidentiary hearing on November 29, 2011, Company witness Yarbrough provided a full and adequate response to Mr. Deddo's concern about the three-phase non-energized line in Bryson City. However, it does not appear that Duke Energy Carolinas has fully responded to Mr. Deddo's concern about the rotten poles on his property.

High Point

Kay Hutchins-Self, 5300 Fieldbrook Drive, Greensboro, North Carolina: Ms. Hutchins-Self testified that: (a) 200 feet of her property was being used illegally by Duke Energy Carolinas, and (b) the Company was making unreasonable demands in regard to her request that the meter at her home be checked for accuracy in consideration of a significant increase in her electric bill. Company witness Yarbrough, in response to questions at the November 29, 2011 evidentiary hearing by Commissioner Brown-Bland, responded fully and adequately with regard to Ms. Hutchins-Self's testimony concerning use of her land. However, it does not appear that Duke Energy Carolinas has fully responded to Ms. Hutchins-Self's concern about the accuracy of her electric meter.

Durham

No public witness testified during the public hearing held in Durham regarding individual quality of service or other matters that warrant further review and consideration by Duke Energy Carolinas and the Commission in this docket.

Raleigh

David Monteith, Bryson City, North Carolina: He testified that he came to the Raleigh hearing from Swain County. He is a Swain County Commissioner. Mr. Monteith testified that Duke Energy Carolinas previously stated that it would never spray in the Swain County area, but the Company is spraying in the area instead of cutting back the vegetation. In response to questions by the Chairman at the November 29, 2011 evidentiary hearing, Company witness Yarbrough testified that there might be a misconception about the herbicide option. She stated that it is an option for individual property owners to select a herbicide management program or to request that the Company not use herbicides on rights-of-way adjoining their property.

Mr. Monteith also testified that it takes Duke Energy Carolinas hours to respond to simple power outages where it used to only take 5, 10, or 15 minutes.

Mr. Monteith further testified that many people pay their electric bills in cash at the Radio Shack and are charged $1.50 to pay cash. Company witness Yarbrough testified that she had a local representative contact Mr. Monteith to let him know that the Duke Energy Carolinas authorized pay location in Bryson City is Parton's Trading Post, not the Radio Shack.

Based on the foregoing and the entire record in this proceeding, the Commission finds and concludes that Duke Energy Carolinas should be required to use its best efforts to contact each public witness identified hereinabove, not later than 20 days after the date of this Order, for the purpose of discussing, determining, and/or documenting: (a) the exact nature of each customer's unresolved complaint; (b) the specific reasons underlying and/or the basis of each complaint; (c) the validity of each complaint; (d) the remedial action required, if any, to resolve the complaint; (e) the cost, if any, the Company would propose to recover directly and/or exclusively from the customer associated with remediation of any given complaint, including a full explanation as to why such cost recovery would be appropriate; and (f) an estimate of the timeframe within which each valid complaint will be resolved. Additionally, Duke Energy Carolinas should be required to file comprehensive, detailed reports with the Commission in this docket describing its actions with regard to each complaint. The Company's initial report, which should be filed not later than 45 days after the date of this Order, should include, at a minimum, the information and data obtained in compliance with the foregoing Commission requirements. Subsequent reports, which should be filed at 30-day intervals following the filing of the initial report, should clearly and comprehensively set forth a listing of those complaints that have been resolved, including the date of resolution, and a listing and the status of any unresolved complaints, including the projected date of resolution. This reporting requirement should remain in effect pending further order of the Commission.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by Duke Energy Carolinas, the Public Staff and Time Warner is hereby approved, except for Paragraph 5.E. and modifications to Paragraph 9.F., as set forth in this Order;

2. That Duke Energy Carolinas shall be allowed to increase its rates and charges effective for service rendered on and after February 1, 2012, so as to produce an increase in gross annual revenue for its North Carolina retail operations of $309,033,000 (as measured cumulatively from present rates, on an annualized basis) based upon the adjusted test year level of operations, as set forth in this Order;

3. That the approved base fuel and fuel-related cost factor is 2.3935 cents per kWh, excluding gross receipts tax and regulatory fee. This base fuel and fuel-related cost factor, including the EMFs, results in the following fuel and fuel-related cost factors approved by the Commission in Docket No. E-7, Sub 982: 2.3836 cents per kWh for the Residential class; 2.3687 cents per kWh for the Commercial class; and 2.3583 cents per kWh for the Industrial class;

4. That the DSM deferral account balance rider of 0.0140 cents per kWh, excluding gross receipts tax and regulatory fee, which is scheduled to expire December 31, 2012, remains in effect;

5. That the base rates approved in this proceeding shall be considered to include: (a) an increment amount for use in the annual proceeding to adjust the EDPR, as approved in Docket No. E-7, Sub 828; and (b) decrement amounts of 0.0642 cents per kWh and 0.0067 cents per kWh (both excluding gross receipts tax and regulatory fee), for flowback of BPM Net Revenues and Non-Firm Point-to-Point Transmission Revenues, respectively, for purposes of measuring the continuing annual adjustment to the BPM True-Up Rider;

6. That the aspects of rate design agreed upon in the Stipulation, with the exception of those regarding OPT rates, are approved and shall be implemented;

7. That Duke Energy Carolinas shall reduce the rate differential between Rate Schedules OPT-I/OPT-H and OPT-G by one-third;

8. That within 90 days of the date of this Order, Duke Energy Carolinas and the Public Staff shall meet with the City of Durham, and representatives of other interested Duke Energy Carolinas' municipal customers, to discuss the fairness of the rates in Schedule GL and the Company's procedures for detection, reporting and repair of malfunctioning street lighting in an attempt to resolve these issues, if possible, before the Company's next general rate case proceeding;

9. That beginning the effective date of the base rates approved herein, Duke Energy Carolinas shall implement a 12-month Costal Wind Project Rider to recover the costs agreed upon in Paragraph 9.D. of the Stipulation, as set forth in this Order;

10. That by July 1, 2012, Duke Energy Carolinas shall make a one-time $11,000,000 shareholder contribution to agencies that provide energy assistance to low-income customers in the Company's North Carolina service territory, as set forth in this Order;

11. That the Company shall review outside services for 2011 and determine whether any costs have been improperly charged to North Carolina retail operations, and shall propose safeguards to prevent the charging of outside services to accounts other than Account 923, and shall file a verified report on its review and proposals by July 1, 2012;

12. That within 120 days of this Order, Duke Energy Carolinas shall implement a process for the detection and remedy of stopped electric meters, as set forth in this Order;

13. That within 90 days of the date of this Order, Duke Energy Carolinas shall provide in a new docket information regarding the Company's vegetation management policies, as set forth in this Order;

14. That by the filing date of its next general rate case, the Company shall provide the Public Staff with (i) a detailed reconciliation of the per books amounts in its accounting records to the Cost of Service Study, showing the accounts and amounts included in each line item of the Cost of Service Study and (ii) all work papers supporting any allocations not shown in the filed Cost of Service Study;

15. That the Company shall provide the Public Staff with a list of all outside services charges to Duke Energy Carolinas not included in the North Carolina Supplemental Financial Reports information, whether the services were obtained directly or through a service company. The Company shall provide this information at the time of its annual filings of all future North Carolina Supplemental Financial Reports provided with Duke Energy Carolinas' FERC Form 1;

16. That within 30 days of this Order, but no later than ten business days prior to the effective date of the new rates, Duke Energy Carolinas shall file for Commission approval five copies of all rate schedules designed to comply with this Order, accompanied by calculations showing the revenues that will be produced by the rates for each schedule, which shall include a schedule comparing the revenue that was produced by the filed schedules during the test period with the revenue that will be produced under the proposed settlement schedules (in the format of Bailey Exhibit 2), and a schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule (in the format of Bailey Exhibit 4);

17. That Duke Energy Carolinas shall submit a proposed customer notice to the Commission for review and approval, and upon approval of the notice by the Commission shall give appropriate notice of the approved rate increase by mailing the notice to each of its North Carolina retail customers during the billing cycle following the effective date of the new rates and upon expiration of the riders set forth in Paragraph 2.D of the Stipulation, as applicable;

18. That the Company shall continue to file annual cost of service studies based on both the SCP and SWPA methodologies, and in its next general rate case filing the Company shall prepare cost of service studies based on both methodologies. The studies shall be included in Item 45 of NCUC Form E-1 of the minimum filing requirements for a general rate case application (or in the corresponding section of any amended set of minimum filing requirements); and

19. That Duke Energy Carolinas shall, with regard to the unresolved service quality issues raised by the public witnesses discussed herein, investigate and attempt to resolve those issues. Further, the Company shall file reports with the Commission in a manner consistent with the guidelines set forth in this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the _27th_ day of January, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Bh012712.01

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 989

In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	)))))	**AGREEMENT AND STIPULATION OF SETTLEMENT**

Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company") and the Public Staff, North Carolinas Utilities Commission (the "Public Staff"), collectively referred to herein as the Stipulating Parties, through counsel and pursuant to N.C. Gen. Stat. § 62-69, respectfully submit the following Agreement and Stipulation of Settlement ("Stipulation") for consideration by the North Carolina Utilities Commission ("Commission") in the above captioned docket. The Stipulating Parties hereby agree and stipulate as follows:

1. BACKGROUND.

A On July 1, 2011, Duke Energy Carolinas filed an application ("Application") for a general rate increase, pursuant to N.C. Gen. Stat. §§ 62-133 and -134 and Commission Rule R1-17, along with direct testimony and exhibits requesting a non-fuel base rate increase (and net total rate increase) of approximately $646,057,000. On October 7 and October 14, 2011, respectively, the Company filed supplemental direct testimony and exhibits and second supplemental direct testimony and exhibits, updating its Application and its requested base rate increase, resulting in an updated increase to non-fuel base rates (and net total rates) of $637,969,000. Intervenors, including the Public Staff, filed testimony and exhibits in this Docket on November 1, 2011. The Company filed rebuttal testimony on November 16 and 17, 2011. The parties to this proceeding have conducted substantial discovery on the issues raised in the Application, as well as on the direct testimony of the Company and the testimony of the intervenors. Discovery is still proceeding on certain items.

B. Subsequent to both the filing of the intervenors' testimony and the filing of the Company's rebuttal testimony, the Stipulating Parties reached agreement in principle with respect to the revenue requirement issues presented by the Company's Application. As a result of further negotiations and prior to the date of this Stipulation, the Stipulating Parties have been able to reach agreement as to all of the major issues in this docket.

The Stipulating Parties agree to the terms and conditions set forth below.

2. RATE INCREASE.

A. Subject to the provisions of Paragraph 2(D) and 2(E) of this Stipulation, Duke Energy Carolinas will adjust its North Carolina retail base rates and tariffs to produce a total increase in annual sales revenues of $309,033,000 from its North Carolina retail electric

operations.[1] The Stipulating Parties agree that these revenues are intended to provide Duke Energy Carolinas, through sound management, the opportunity to earn a return on equity of 10.5%. This return on equity will be applied to the common equity component of the following capital structure:

Long term Debt…………..47%
Member's Equity…………53%

The embedded cost of debt agreed to by the Stipulating Parties as appropriate and reasonable for purposes of this proceeding is 5.41%. The overall rate of return resulting from the above inputs is 8.11%.

B. Duke Energy Carolinas' Application and the testimony and exhibits of all parties (including the schedules referenced in paragraph 2.C. of this Stipulation) provide sufficient support for the annual revenue requirement agreed to in this Stipulation.

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[1] This is the increase in non-fuel base revenue requirement. It is also equal to the increase in net total revenue requirement because the increase in base fuel rates will be offset by elimination of certain fuel riders currently in effect.

C. Settlement Exhibit 3 attached to this Stipulation sets forth the gross revenues, operating revenue deductions, rate base, and rate of return that the Stipulating Parties agree are appropriate for use in this proceeding, subject to the provisions of Paragraphs 7 and 10 of this Stipulation. The Stipulating Parties accept and will not challenge these amounts in this proceeding.

D. Rates shall be designed such that no customer class shall receive a net total cumulative increase stated on an annual basis of more than 7.21%.

E. Within 30 days after the Commission's issuance of an order accepting this Stipulation, but no later than ten business days prior to the effective date of the new rates, Duke Energy Carolinas will file for Commission approval five copies of all rate schedules designed to comply with the paragraphs above, accompanied by calculations showing the revenues that will be produced by the rates for each schedule, which shall include a schedule comparing the revenue produced by the filed schedules during the test period with the revenue that will be produced under the proposed settlement schedules (in the format of Bailey Exhibit 2), and a schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule (in the format of Bailey Exhibit 4).

F. The effective date of the rate change ("Effective Date") shall be February 1, 2012, provided the Commission issues an order approving the rate schedules submitted pursuant to paragraph 2.E above ("Approval Order") by December 31, 2011. If the Approval Order is issued later than December 31, 2011, the Effective Date shall be extended by the number of days between December 31, 2011, and the date the Approval Order is issued; provided, however, that the Company reserves its rights to implement rates under bond pursuant to N.C. Gen .Stat. § 62-135 on or after February 1, 2012.

G. In consideration of settlement, the Company waives its right to increase the amount of construction work in progress ("CWIP") in rate base for any expenditures associated with Cliffside Unit 6 above the North Carolina retail portion of the $1,023,521,000 system amount included in the Company's rate base in Docket No. E-7, Sub 909. Instead, the Company will continue to capitalize allowance for funds used during construction ("AFUDC") on all expenditures associated with Cliffside Unit 6 not included in rate base as a result of the Commission's Order in Docket E-7, Sub 909.

H. In consideration of settlement, and to achieve the recommended rate increase agreed to herein, the Stipulating Parties agree that the Company will as part of this proceeding flow through to ratepayers the North Carolina retail allocated share of its September 30, 2011, balance of accumulated Environmental Protection Agency sulfur dioxide auction proceeds, which have been maintained to date as a regulatory liability in the Company's books and records.

3. **BASE FUEL AND FUEL-RELATED COST FACTORS**. The base fuel and fuel related cost factor included in Duke Energy Carolinas' base rates will be 2.3935 ¢/kWh, excluding gross receipts tax and regulatory fee. The total of the approved base and rider components of the fuel and fuel related cost factors, by customer class, including the Experience Modification factors and related interest, will be as set forth in the following table:

	Residential		Commercial		Industrial	
Base Fuel and Fuel-Related Cost Effective February 1, 2012	2.3935	¢	2.3935	¢	2.3935	¢
Adjustment to Base Fuel Cost	0.0006		(0.0004)		(0.0009)	
Approved Fuel and Fuel-Related Cost Factor, Docket E-7, Sub 982	2.3941	¢	2.3931	¢	2.3926	¢
Experience Modification Factor, Docket E-7, Sub 982	(0.0093)		(0.0215)		(0.0303)	
Experience Modification Interest , Docket E-7, Sub 982	(0.0012)		(0.0029)		(0.0040)	
Total Approved Fuel and Fuel-Related Cost Factor	2.3836	¢	2.3687	¢	2.3583	¢
(¢/kWh excluding gross receipts tax and regulatory fees)						

The differentials between the composite base fuel and fuel-related cost factors and total fuel and fuel-related cost factors by customer class (as shown in the above table) shall be included in the rider components of Duke Energy Carolinas' Fuel Cost Adjustment Rider (NC), and shall be subject to modification in the Company's annual fuel charge proceedings.

4. **ALLOCATION METHODOLOGIES.**

A. Duke Energy Carolinas has based its filing in this Docket on the Summer Coincident Peak ("SCP") methodology for cost allocation among jurisdictions and among customer classes. The Public Staff advocates the use of the Summer-Winter Peak and Average ("SWPA") methodology for those purposes.

B. The Stipulating Parties agree that the use of the SCP methodology shall not be a precedent for and may be contested in future general rate case proceedings, and that the Company will continue to file annual cost of service studies based on both the SCP and SWPA methodologies. The Company also agrees that it will not cite Commission approval of the Stipulation as support for approval of the SCP methodology in future proceedings.

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5. **RATE DESIGN**. The Stipulating Parties agree upon the following with regard to rate schedules to be filed by the Company in compliance with the Approval Order as provided in paragraph 2.E. and other rate design matters proposed by Duke Energy Carolinas:

A. Each rate component for each rate schedule, including the Basic Facility Charges, shall be modified by an equal percentage to arrive at the average increase depicted in Settlement Exhibit 2, Column Y.

B. The Extra Facilities Rate shall be adjusted prospectively consistent with the cost of capital and capital structure described in Paragraph 2A and associated income tax effects. The Stipulating Parties agree to further discussions to effectuate this commitment.

C. The Stipulating Parties agree that the Company may implement its Schedule HP proposal, as set forth in Company Witness Bailey's testimony, to revise the calculation of rationing charges and the criteria associated with adjustments to the Customer Baseline Demand. In addition, the wording of Schedule HP shall be revised as recommended in Public Staff Witness Lowdermilk's Exhibit 2.

D. The Stipulating Parties agree that the Company may implement its proposed Transformation Discount Pilot for a period of two years, as provided in the direct testimony of Company Witness Bailey. The Stipulating Parties further agree that the Company should provide an annual report on the number of customers participating in the pilot, the rate schedule under which the customer is being served, and the aggregate demand served (kilowatts) associated with this pilot. Six months prior to the end of the pilot the Company shall file a request to either continue and expand the pilot to all non-residential customers with qualifying loads, or request that the pilot be canceled.

E. Rate Schedules OPT-G and OPT-I shall not be consolidated at this time. The Stipulating Parties agree to consider a three-step phase-in of the consolidation to be presented in the Company's next general rate proceeding.

F. The Company will develop a plan to transition customers served on Rate Schedules YL and FL-N to Rate Schedules OL and FL, respectively, and to present the transition plan in its next general rate case.

G. The Stipulating Parties agree that further investigation is needed to develop a proposal for low use, high load factor non-residential loads, including cable television amplifiers, and agree to work together with the intent that the Company will file such a proposal in its next rate case.

H. The Stipulating Parties recognize and acknowledge that as a result of changes to rate schedules, it is anticipated that customers will migrate to different rate schedules. In the development of final rates, Duke Energy Carolinas shall calculate the expected lost revenue due to migrations and recover 50% of this amount from the classes of customers in which migration occurs. Duke Energy Carolinas shall provide the Public Staff with a copy of the calculations and supporting data on or before December 16, 2011. The Public Staff retains the right to contest the reasonableness of the adjustment that the Company proposes to incorporate for expected lost

revenue due to migrations and to request an evidentiary hearing for the purpose of resolving any such dispute.

I. The Stipulating Parties will continue to investigate how rate design can effectively and fairly promote greater energy efficiency.

J. The Stipulating Parties will continue to investigate the feasibility of dynamic pricing rate structures, including but not limited to critical peak pricing and time-of-use rate structures for both residential and non-residential customers, with the intent to include such dynamic pricing rate structures as a pilot program in the Company's next general rate case proceeding.

6. CONTINUING RIDERS AND BASE RATE AMOUNTS RELATED TO CONTINUING RIDERS.

A. The terminating demand-side management (DSM) deferral account balance rider of 0.0140 cents per kWh, excluding gross receipts tax, scheduled to expire December 31, 2012, remains in effect through December 31, 2012, as previously approved in Docket No. E-7, Sub 828 effective January 1, 2008.

B. The base rates approved in this proceeding include the following amounts:

(i) An increment amount for use in the annual proceeding to adjust the Existing DSM Program Rider, as approved in Docket No. E-7, Sub 828, effective January 1, 2008. The increment amount will be provided at the time the Company makes its compliance filing in this docket.

(ii) Decrement amounts of 0.0642 cents per kWh and 0.0067 cents per kWh (both excluding gross receipts tax), for flow back of, respectively, BPM Net Revenues and Non-Firm Point-to-Point Transmission Revenues, for purposes of measuring the continuing annual adjustment to the BPM True-Up Rider as previously approved in Docket No. E-7, Sub 828, effective January 1, 2008.

7. STIPULATED COST OF SERVICE ADJUSTMENTS. For settlement purposes only, the Stipulating Parties have agreed to certain cost of service adjustments as reflected in the Rebuttal Testimony of Company Witness Shrum and as further negotiated by the Stipulating Parties. The agreement of the Stipulating Parties on resolution of these issues is reflected in Settlement Exhibit 1. No Stipulating Party waives any right to assert any position in any future proceeding or docket before the Commission and in any court, as the adjustments on Settlement Exhibit 1 are strictly for purposes of compromise and are intended to show a rational basis for reaching the revenue requirement without either party conceding any specific adjustment. The Stipulating Parties agree that settlement on these issues will not be used as a rationale for future arguments on contested issues brought before the Commission.

8. QUALITY OF ELECTRIC SERVICE. The Stipulating Parties agree that the overall quality of electric service provided by Duke Energy Carolinas is good.

9. ADDITIONAL AREAS OF AGREEMENT. The Stipulating Parties agree to the following additional terms:

A. The Company will make a one-time $11,000,000 shareholder contribution to agencies that provide energy assistance to low-income customers for uses such as those identified in Docket No. E-7, Sub 795. The Company will consult with the Public Staff and submit a proposal within 60 days of the Approval Order and such funds will be paid from shareholders to the appropriate agencies by July 1, 2012. These funds are to be used exclusively to provide energy assistance to the North Carolina retail customers of Duke Energy Carolinas.

B. The Stipulating Parties agree to the positions set out on pages 14 and 15 of the Rebuttal Testimony of Company Witness Shrum regarding possible accounting changes for the generating mix of Plants Buck and Bridgewater. The Public Staff reserves the right to challenge any deferral application the Company files to recover costs for new plant at Plants Buck and Bridgewater.

C. The Stipulating Parties agree that in the event Plant Buck is not online and in commercial operation by the close of the hearing set to commence November 28, 2011, the Company may request that the Commission leave the hearing open no longer than two weeks so that the Company can file proof that the plant is online and in commercial operation.

D. The Company filed its Coastal Wind Rider as a matter of administrative convenience in this docket. The Stipulating Parties agree that the amount to be recovered through this Rider will be based on Duke's calculation of costs incurred through the end of March 2010 ($1,191,696 plus 10.5% return calculated on a 53% share of equity for the capital structure, totaling $1,396,232).

E. The Company will review outside services for the 2011 calendar year to investigate whether any costs are or have been improperly charged to North Carolina retail operations, and will propose safeguards to prevent the charging of outside services to accounts other than Account 923, per recommendation of Public Staff Witness Peedin and agreement by Company Witness Shrum. Duke will file a verified report on its review by July 1, 2012.

F. The Company agrees to the vegetation management policy and procedures review and filing as articulated in the testimony of Public Staff Witness Lowdermilk. Accordingly, within ninety days of the Approval Order, the Company will review its vegetation management policies and procedures, develop a clear, comprehensive, consistent, and publicly-available policy description, file it with the Commission, and publish it on its website in a publicly available manner. The Stipulating Parties agree to further discussions to effectuate these commitments.

G. As to the stopped meter issue raised in the testimony of Public Staff Witness Lowdermilk, the Company agrees to send a letter to customers after 4 months of no usage, except for customers on Schedules SGS and LGS utilizing the annual minimum billing options and customers that the Company can identify as seasonal customers. The Company will work with the Public Staff as to the content of the letter. The Company will implement this procedure within 120 days after the Commission issues its Approval Order in this case. Once implemented, the Company will report to the Public Staff and Commission that implementation is complete. The Company will meet with the Public Staff within six months of implementation and file a formal report to the Commission within a year after implementation that contains the

following: (1) the number of stopped meter customer letters mailed, (2) the number of customer responses received, (3) the number of stopped meters discovered as a result of the customer contact, (4) the number of months back billed for each stopped meter discovered, and (5) the amount of the back billing for each meter.

H. The Company agrees to provide the Public Staff with (i) a detailed reconciliation of the per books amounts in its accounting records to the Cost of Service Study, showing which accounts and amounts are included in each line item of the Cost of Service Study and (ii) all work papers supporting any allocations not shown in the filed Cost of Service Study. The Company shall provide this information by the filing date of its next general rate case.

I. The Company agrees to provide the Public Staff with a list of all outside services charges to Duke Energy Carolinas not included in the North Carolina Supplemental Financial Reports information, whether obtained directly or through a service company. The Company shall provide this information at the time of its annual filings of all future North Carolina Supplemental Financial Reports provided with the Duke Energy Carolinas' FERC Form 1.

J. The Stipulating Parties have different opinions regarding the Company's contract with General Electric that covered repair of the Cliffside Unit 5 turbine bearing. This disagreement does not affect monetary issues in this Docket, and the Stipulating Parties agree that the matter does not need resolution in light of this Agreement.

10. 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.

B. Neither this Stipulation nor any of the terms shall be admissible in any court or Commission except insofar as such court or Commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Stipulation. This Stipulation shall not be cited as precedent by any of the Stipulating Parties with regard to any issue in any other proceeding or docket before this Commission or in any court.

C. 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 any position in any future proceeding or docket before the Commission and in any court.

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

11. RECEIPT OF TESTIMONY AND WAIVER OF CROSS-EXAMINATION. The pre-filed testimony and exhibits of the Stipulating Parties may be received in evidence without objection, and each Stipulating Party waives all right to cross examine any witness with respect to such pre-filed testimony and exhibits. If, however, questions are asked by any

Commissioner, or if questions are asked or positions are taken by any person who is not a Stipulating Party, then any Stipulating Party may respond to such questions by presenting testimony or exhibits and cross-examining any witness with respect to such testimony and exhibits.

12. 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 approves this Stipulation subject to any change or condition or if the Commission's approval of this Stipulation is rejected or conditioned by a reviewing court, the Parties agree to meet and discuss the applicable Commission or court order within five business days of its issuance and to attempt in good faith to determine if they are willing to modify the 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, each Party retains the right to seek additional procedures before the Commission, including cross-examination of witnesses, with respect to issues addressed by the Stipulation and shall be bound or prejudiced by the terms and conditions of the Stipulation.

13. COUNTERPARTS. 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.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 989

In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	)))))	**AMENDMENT TO AGREEMENT AND STIPULATION OF SETTLEMENT**

Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company") and the Public Staff, North Carolinas Utilities Commission (the "Public Staff"), collectively referred to herein as the Stipulating Parties, through counsel and pursuant to N.C. Gen. Stat. § 62-69, filed on November 28, 2011, an Agreement and Stipulation of Settlement ("Stipulation") for consideration by the North Carolina Utilities Commission ("Commission") in the above captioned docket. As a result of further discussions, the Stipulating Parties have decided to amend the Stipulation as set out below:

1. Time Warner Cable, Inc., shall be a Stipulating Party in addition to Duke Energy Carolinas and the Public Staff and the term "Stipulating Parties" shall include Time Warner Cable, Inc.

2. Part 5. G. of the Stipulation is amended to state:

   The Stipulating Parties agree that Duke Energy Carolinas shall create a provision within Rate Schedule SGS for cable television power supplies as a pilot to be in effect until new rates go into effect as a result of the Company's next general rate case. The provision will provide for an energy rate of 5.5 cents/kWh applicable to all energy consumed by cable television power supplies, plus the basic facilities charges established for Rate Schedule SGS in this proceeding. Information from the pilot period will be used to study the cost justification and feasibility of an appropriate on-going provision for all low use, high load factor non-residential loads, including cable television power supplies. Such information will be the basis for a recommendation to be included in the next general rate case application of Duke Energy Carolinas, and the Stipulating Parties may provide updated information, if appropriate, as the study continues through the close of hearing. The Company will share the results of its study with interested parties, with the intent that an on-going provision or separate rate for low use, high load factor non-residential customers may be proposed in the next general rate case following completion of the study.

3. All other terms of the Stipulation filed in this Docket on November 28, 2011, remain the same.

4. This Amendment to Agreement and Stipulation of Settlement 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.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 989

In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	)))))	**SECOND AMENDMENT TO AGREEMENT AND STIPULATION OF SETTLEMENT**

Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company") and the Public Staff, North Carolinas Utilities Commission (the "Public Staff"), collectively referred to herein as the Stipulating Parties, through counsel and pursuant to N.C. Gen. Stat. § 62-69, filed on November 28, 2011, an Agreement and Stipulation of Settlement ("Stipulation") for consideration by the North Carolina Utilities Commission ("Commission") in the above captioned docket. The Company and Public Staff also filed an Amendment to the Stipulation on December 2, 2011 by which Time Warner Cable, Inc. ("TWC") became a Stipulating Party. As a result of further discussions and to clarify the effects of the December 2 Amendment, the Stipulating Parties have decided to further amend the Stipulation as set out below:

5. Part 5. A. of the Stipulation should be replaced in its entirety with the following language:

> Each rate component for each rate schedule, including the Basic Facility Charges, shall be modified by an equal percentage to arrive at the average increase depicted in Settlement Exhibit 2, Column Y, except to the extent needed to implement Part 5. G. below. This does not include any rate effects stemming from any other Commission Order.

6. All other terms of the Stipulation filed in this Docket on November 28, 2011, and amended on December 2, 2011 remain the same.

7. This Second Amendment to Agreement and Stipulation of Settlement 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.

DOCKET NO. G-9, SUB 614

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Piedmont Natural Gas Company, Inc., 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, October 2, 2012, 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 Susan W. Rabon and Lucy T. Allen

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 28202-4003

For the Using and Consuming Public:

Elizabeth A. Denning, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On August 1, 2012, pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), Piedmont Natural Gas Company, Inc. (Piedmont or the Company), filed the direct testimony of Frank Yoho, Senior Vice President - Commercial Operations; the direct testimony and exhibits of Keith P. Maust, Managing Director, Gas Supply and Scheduling; and, the direct testimony and exhibits of Robert L. Thornton, Director of Gas and Regulatory Accounting, attesting to the prudence of the Company's gas purchasing policies and the accuracy of the Company's gas cost accounting for the twelve-month period ended May 31, 2012.

On August 2, 2012, 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, October 2, 2012, set prefiled testimony dates, and required the Company to give notice to its customers of the hearing on this matter.

On August 8, 2012, Piedmont filed a revised version of Company witness Maust's Exhibit_(KPM-3), hereinafter referred to as Errata Exhibit_(KPM-3).

On August 22, 2012, Carolina Utility Customers Association, Inc., filed a Petition to Intervene, which was granted by the Commission on August 27, 2012.

August 24, 2012, Piedmont filed a revised version of Company witness Maust's Exhibit_(KPM-5), hereinafter referred to Errata Exhibit_(KPM-5).

On September 17, 2012, the Public Staff filed the direct testimony of Michelle M. Boswell, Staff Accountant, Accounting Division; the direct testimony and exhibits of Jan A. Larsen, Utilities Engineer, Natural Gas Division; and, the direct testimony of Julie G. Perry, Supervisor, Natural Gas Section, Accounting Division.

On September 25, 2012, Piedmont and the Public Staff filed a Joint Motion to Excuse Appearance of Witnesses and Accept Testimony, which was granted by the Commission on September 26, 2012.

On September 28, 2012, the Company filed its affidavits of publication.

On October 2, 2012, 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 October 18, 2012, the Joint Proposed Order of Piedmont and the Public Staff was filed.

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.

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 the twelve months ended May 31, 2012.

5. The Company has properly accounted for its gas costs incurred during the review period.

6. During the review period, the Company incurred total costs of gas expensed of $311,805,837, which was comprised of demand and storage charges of $114,093,795, commodity gas costs of $214,330,512, and other gas costs of ($16,618,469).

7. At May 31, 2012, the Company had a debit balance of $29,713,758 in its All Customers Deferred Account and a credit balance of $28,449,628 in its Sales Customers Only Deferred Account.

8. Piedmont actively participated in secondary market transactions, earning $19,097,633 of margin for the benefit of 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. At May 31, 2012, the balance in the Company's Hedging Deferred Account was a debit balance of $7,763,001.

11. It is appropriate for the Company to transfer the $7,763,001 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 credit balance of $20,686,627.

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. As ordered by the Commission in its Order on Annual Review of Gas Costs issued on January 25, 2012, in Docket No. G-9, Sub 595 (Sub 595 Order), the Company filed with the Commission a detailed description of its gas capacity planning.

15. As ordered by the Commission in its Sub 595 Order, the Public Staff filed with the Commission a detailed description of the results of its analysis of the Company's determination of design day demand.

16. The Company's gas purchasing policy and practices during the review period were prudent.

17. The Company's gas costs during the review period were prudently incurred and the Company should be permitted to recover 100 percent of such prudently incurred gas costs.

18. The Company should implement the temporary rate increments applicable to the All Customers Deferred Account and the temporary rate decrement applicable to the Sales Customers Only Deferred Account proposed by Company witness Thornton and agreed to by Public Staff witness Larsen.

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 Yoho, Maust, and Thornton. These findings are essentially informational, procedural, or jurisdictional in nature and are based on uncontested evidence.

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 Yoho, Maust, and Thornton and the testimony of Public Staff witnesses Boswell, Larsen, and Perry.

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, 2012, as the end date of the review period for the Company in this proceeding. Commission Rule R1-17(k)(6)(c) requires the filing by the Company of certain information and data showing weather-normalized sales volumes, workpapers, and direct testimony and exhibits supporting the information.

Company witness Thornton 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 Thornton included the annual data required by Commission Rule R1-17(k)(6)(c) as Exhibit_(RLT-1) to his direct testimony. Public Staff witnesses Boswell and Larsen stated that they had presented results of their review of the gas cost information filed by Piedmont in accordance with G.S. 62-133.4 and Commission Rule R1-17(k).

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, 2012.

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 Thornton and Public Staff witness Boswell.

Company witness Thornton testified that Piedmont incurred gas costs of $328,424,307 during the review period and received $311,805,837 through rates. The total cost of gas expensed of $311,805,837 was comprised of demand and storage charges of $114,093,795, commodity gas costs of $214,330,512, and other gas costs of ($16,618,469).

Company witness Thornton's prefiled testimony and exhibits reflected a Sales Customers Only Deferred Account credit balance of $28,449,628 and an All Customers Deferred Account debit balance of $29,713,758 as of May 31, 2012. Public Staff witness Boswell 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 concludes that the appropriate level of total costs of gas expensed for this proceeding is $311,805,837. The Commission further concludes that the appropriate balances of the Company's deferred accounts as of May 31, 2012, are a credit balance of $28,449,628 in its Sales Customers Only Deferred Account and a debit balance of $29,713,758 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 witnesses Maust and Thornton and Public Staff witness Boswell.

Company witness Maust testified that Piedmont utilized the flexibility available within its supply and capacity contracts to purchase and dispatch gas, release capacity and initiate secondary market sales in the most cost-effective manner. Witness Maust stated that for long-term delivered sales (longer than one month), Piedmont solicits bids from potential buyers and awards volumes based on bids received. Witness Maust further stated that, for short-term transactions (daily or monthly), Piedmont monitors prices and volumes on the Intercontinental Exchange. The Company also evaluates the amount of supply available for sale and weighs that against current market conditions in formulating its sales strategy.

Public Staff witness Boswell testified that the Company earned actual margins of $30,317,312 on secondary market transactions and credited the All Customers Deferred Account in the amount of $19,097,633 for the benefit of ratepayers ($30,317,312 x 83.99% NC demand allocator x 75% ratepayer sharing percent). The actual margins 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, earning $19,097,633 of margin for the benefit of 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 Maust and Thornton and the testimony of Public Staff witnesses Boswell and Perry.

Company witness Thornton stated in his testimony that the Company had a total debit balance of $7,763,001 in its Hedging Deferred Account at May 31, 2012. Public Staff witness Perry testified that these costs were composed of Economic (Gain)/Loss – Closed Positions of $0, Premiums Paid – Closed Positions of $2,075,495, Premiums Paid – Open Positions of $4,738,655, Brokerage Fees and Commissions of $66,278, and Interest on the Hedging Deferred Account of $882,573.

Company witness Maust testified that Piedmont's Hedging Plan accomplished its goal of protecting customers in North Carolina in the event of sudden increases in the price of gas. Witness Maust stated the Company made a change to its Hedging Plan effective January 1, 2012, by electing not to engage in time-driven hedges under the program when the NYMEX futures price for natural gas is at or above the 60th decile level of historic prices as calculated by its program. He further testified that this change will allow the Company to avoid hedging in unfavorable price environments. Witness Maust stated that the Company continues to utilize storage as a physical hedge to stabilize cost, and that the Company's Equal Payment Plan and the use of the Purchased Gas Adjustment benchmark price and deferred cost accounting also allowed for a smoothing effect on gas price volatility.

Public Staff witness Perry testified that the Public Staff's review of the Company's hedging activities is performed on an ongoing basis and includes analysis and evaluation of 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, periodic reports on the market values of the various financial instruments used by the Company to hedge, monthly Hedging Program Status Reports, monthly reports reconciling the Hedging Program Status Report and the hedging deferred account report, minutes from the meetings of Piedmont's Energy Price Risk Management Committee (EPRMC), minutes from the meetings of the 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. Witness Perry further testified that the Company's change to its hedging program was based on Piedmont's evaluation that market conditions in the wholesale commodity market for natural gas are more stable than they have been in the past and that the Company's action was intended to adjust its hedging plan as market conditions evolve and to effectuate the ability of Piedmont to hedge its gas costs at levels below the previous minimum of 22.5% of normalized annual sales volumes, including the possibility of not hedging at all should prices be at or near historical highs. The hedging program change was effective for hedges placed after November 1, 2011.

Public Staff witness Perry concluded that Piedmont's hedging activities were reasonable and prudent and that the $7,763,001 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. Based on this testimony, Public Staff witness Boswell recommended that the balance of the Sales Customers Only Deferred Account as of May 31, 2012, should be a credit, owed to the customers, of $20,686,627.

As demonstrated by 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 that the $7,763,001 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 credit balance of $20,686,627.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-17

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Yoho and Maust and Public Staff witness Larsen.

Company witness Maust 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 Maust testified that all of these components are interrelated and that the Company weighs the relative importance of each of these five factors in developing its overall gas supply portfolio to meet the needs of its customers.

Witness Maust further testified that the Company purchases gas supplies under a diverse portfolio of contractual arrangements with a number of reputable gas producers and marketers. Under its firm gas supply contracts, Piedmont pays 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 (daily swing service generally being more expensive than monthly baseload service). Witness Maust testified that the Company identifies the volume and type of supply that it needs to fulfill its market requirements and solicits requests for proposals from a list of suppliers that the gas supply department continuously updates as potential suppliers enter and leave the market place. The type of supply is classified as either baseload or swing and as either firm or interruptible. Witness Maust 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 Maust 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 Maust stated that the Company evaluates the cost of the reservation fees associated with each type of supply and its corresponding bid, and makes a “best cost” decision on which type of supply and supplier to fulfill its needs. Company witness Maust 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 Maust 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 must be kept informed about all aspects of the natural gas industry. The Company, therefore, stays abreast of current issues 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, attending industry seminars, subscribing to industry literature, and following supply and demand developments. Witness Maust further testified that the Company did not make any changes in its best cost gas purchasing policies or practices during the test period. Witnesses Yoho and Maust also indicated that during the past year the Company has taken several additional steps to manage its costs, including reducing the Company’s upstream capacity on Columbia Gulf in an effort to restructure upstream assets and reduce annual demand charges, postponing the planned construction of the on-system Robeson Liquefied Natural Gas facility, 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 witnesses Yoho and Maust testified regarding the market requirements of Piedmont's North Carolina customers and the acquisition of capacity to serve those markets. Witness Maust testified that the Company continues to experience a reduction in normalized usage per customer, which has been evident for some time now, for several reasons, including the increased efficiency of new appliances used by new customers, the replacement of old equipment by existing customers, increased customer awareness of the benefits of conservation measures, and customer implementation of conservation measures. Witness Maust 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 Maust testified that Piedmont will continue to utilize a conservative approach to design day forecasting until more comprehensive data indicates that another approach is appropriate.

Company witnesses Yoho and Maust also provided a detailed description of Piedmont's current capacity levels and its planning process to secure future capacity as ordered by the Commission in its Sub 595 Order. Witness Yoho testified that the Company focuses Piedmont's supply and capacity planning and acquisition activities around its obligations to provide firm sales service to residential, commercial, and industrial customers. He explained that Piedmont is obligated by Commission Rules R6-23 and R6-36 to take reasonable steps to avoid curtailment of service to firm customers and to ensure the adequacy of supplies, both upstream and on Piedmont's system, to avoid such curtailments. Witness Yoho stated that this primary service obligation impacts the Company's approach to supply and capacity planning in several ways: (1) for design day purposes it means the Company plans for upstream supply and capacity rights on the basis of the highest projected firm demand the Company may be called upon to serve plus a reserve margin to provide some protection from upstream service disruptions, and (2) the Company always plans to have sufficient supply and capacity assets to ensure it can meet its design day obligations.

Witness Yoho further testified that Piedmont does not maintain capacity that is truly "excess" to the Company's needs. Piedmont's need to maintain both adequate design day capacity and a reserve margin are the result of several factors. It is commercially impossible for Piedmont to sculpt supply and capacity rights to perfectly match the Company's projected needs on a seasonal or year round basis. Witness Yoho stated, that "we cannot predict with certainty and have no control over weather – which is the single biggest driver of natural gas usage by heat sensitive residential and commercial customers on the system." Witness Yoho further stated that, "we cannot predict with certainty and have no control over the daily demand from industrial and electric generation customers," and "we cannot predict with certainty what our system growth will be in the near or long term."

Company witness Maust testified that Piedmont's design day calculation involves several elements including: (1) the actual throughput and degree days experienced on the most recent day that approached the design day temperature; (2) the day's interruptible sales; (3) the day's actual firm and interruptible transportation quantities; (4) the dekatherm per degree day factor generated from several sources including data that resides in the forecast software program "GASDAY"; and (5) the forecasted number of heat sensitive sales customers expected during the upcoming heating season. Piedmont recalculates its design day annually, and each yearly design day forecast is derived by multiplying the temperature sensitive rate classes' usage for the previous year by the succeeding year's forecasted growth percentage. Witness Maust further testified the Company constructs load duration curves that forecast the Company's firm sales market requirements for normal winter weather conditions and design day winter weather conditions. The supply requirements are plotted in descending order of magnitude, with existing pipeline capacity and storage resources overlaid to expose any supply shortfalls. Witness Maust provided the forecast load duration curves in Exhibit_(KPM-1) and Exhibit_(KPM-2). Witness Maust also provided the design day calculation for the review period and forecasted winter heating seasons in Errata Exhibit_(KPM-3).

Public Staff witness Larsen testified that he 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, witness Larsen testified that the Company's review period gas costs were prudently incurred.

Witness Larsen further testified, in accordance with the Sub 595 Order, that although the scope of Commission Rule R1-17(k) is limited to a historical review period, he 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. Witness Larsen stated that regression analyses are performed by rate classification or Rate Schedule, using actual volumes or consumption by class of firm customers, to determine a base load and heat sensitivity factor. A formula can be derived from base usage and heating sensitivity factor that can project consumption on any given degree day. Witness Larsen testified that this calculation is used in conjunction with projected growth to forecast demand in the future, and that while the results are accurate, they are not absolute as there are many variables in determining peak day demand that change over time. Witness Larsen also testified that efficiency improvements do impact peak day demand calculations, however, since the derivation of peak day demand is based on historical volumes, any effects of customer usage patterns caused by conservation or efficiency improvements are inherently included in the calculations. The results of Public Staff witness Larsen's analysis were provided in Larsen Exhibit No. 1. Witness Larsen testified that Piedmont's planning fell within the range of reasonableness for forecasting.

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% of its prudently incurred gas costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence supporting this finding of fact is contained in the testimony of Company witness Thornton and Public Staff witness Larsen.

Company witness Thornton stated in his testimony that based on the Company's deferred accounts end-of-period balances, as reflected on Thornton Exhibit_(RTL-3) and Exhibit_(RTL-4), he recommends that the increments and 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. Public Staff witness Larsen testified that he had calculated the temporary rate increments applicable to the All Customers Deferred Account balance and the temporary rate decrement applicable to the Sales Customers Only Deferred Account, and his calculations agreed with those proposed by Company witness Thornton.

Based on the foregoing, the Commission concludes that it is appropriate for the Company to remove the temporary rates that were implemented for the All Customers Deferred Account and the Sales Customers Only Deferred Account in Docket No. G-9, Sub 595, and implement the temporary rate increments applicable to the All Customers Deferred Account and the temporary rate decrement applicable to the Sales Customers Only Deferred Account as proposed in Thornton Exhibit_(RTL-3) and Exhibit_(RTL-4).

IT IS, THEREFORE, ORDERED as follows:

1. That the Company's accounting for gas costs during the twelve-month period ended May 31, 2012, is approved;

2. That the gas costs incurred by Piedmont during the twelve-month period ended May 31, 2012, 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 595, and implement the temporary rate increments and decrement for the All Customers and Sales Customers Only Deferred Accounts, respectively, as found appropriate herein, effective for service rendered on and after the first day of the month following the date of this Order; and

4. That Piedmont shall give notice to its customers of the rate changes allowed in this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the _7th_ day of November, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

je110612.01

DOCKET NO. G-5, SUB 533

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 REVIEW
Gas Costs Pursuant to G.S. 62-133.4(c)	)	OF GAS COSTS
and Commission Rule R1-17(k)(6)	)	

HEARD: Tuesday, August 14, 2012, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Susan W. Rabon, Presiding, Commissioners Bryan E. Beatty and Lucy T. Allen

APPEARANCES:

For Public Service Company of North Carolina, Inc.:

Mary Lynne Grigg, McGuireWoods, LLP, 2600 Two Hanover Square, Raleigh, North Carolina 27601

For the Using and Consuming Public:

Gina C. Holt, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On June 1, 2012, 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, and Terina H. Cronin, General Manager, Gas Supply & Commercial and Industrial Marketing, in connection with the annual review of PSNC's gas costs for the twelve-month period ended March 31, 2012.

On June 5, 2012, 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 14, 2012, set prefiled testimony dates, and required the Company to give notice to its customers of the hearing on this matter.

On July 27, 2012, the Public Staff filed the direct testimony of Julie G. Perry, Supervisor, Accounting Division and Catherine L. Eastwood, Staff Accountant, Accounting Division, and the direct testimony and exhibits of Jan A. Larsen, Public Utilities Engineer, Natural Gas Division.

No other party intervened.

On August 6, 2012, PSNC and the Public Staff filed a Joint Motion for Witnesses to be Excused from Appearance at Evidentiary Hearing. On August 8, 2012, the Commission granted the Joint Motion and issued an Order Excusing Witnesses from Attending the Hearing.

On August 13, 2012, the Company filed its Affidavits of Publication.

On August 14, 2012, the matter came before the Commission as scheduled and all prefiled testimony and exhibits were admitted into evidence. No public witnesses appeared at the hearing.

On August 28, 2012, the Public Staff filed corrected pages 13 and 14 of Public Staff witness Eastwood's testimony filed on July 27, 2012.

On September 13, 2012, 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 490,000 winter-peak 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 for this proceeding is the twelve months ended March 31, 2012.

5. During the period of review, PSNC incurred total gas costs of $168,268,424, which was composed of demand and storage charges of $71,218,642, commodity gas costs of $151,341,719, and other gas costs of ($54,291,937).

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 $7,619,954, to its All Customers Deferred Account.

7. At March 31, 2012, the Company had a credit balance of $12,013,671 in its Sales Customers Only Deferred Account and a debit balance of $23,936,586 in its All Customers Deferred Account.

8. The Company has properly accounted for its gas costs incurred during the review period.

9. PSNC's hedging activities during the review period were reasonable and prudent.

10. As of March 31, 2012, the Company had a debit balance of $4,894,267 in its Hedging Deferred Account.

11. It is appropriate to transfer the $4,894,267 debit balance from the Hedging Deferred Account to the Sales Customers Only Deferred Account. Subsequent to the transfer, the Sales Customers Only Deferred Account would have a net credit balance of $7,119,404.

12. PSNC has adopted a gas supply policy that it refers to as a "best cost" supply strategy. This gas supply policy is based upon three primary criteria: supply security, operational flexibility, and the cost of gas.

13. PSNC has a portfolio of long-term and supplemental short-term supply agreements with a variety of suppliers, including producers and independent marketers.

14. The gas costs incurred by PSNC during the review period were prudently incurred.

15. As a result of this proceeding, the Company should implement the temporary rate increments applicable to the All Customers Deferred Account and the temporary rate decrement applicable to the Sales Customers Only Deferred Account proposed by Company witness Paton and agreed to by Public Staff witness Larsen.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 AND 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 AND 4

The evidence for these findings of fact is contained in the testimony of PSNC witnesses Cronin and Paton and Public Staff witness Eastwood. The findings are based on G.S. 62-133.4 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 twelve-month review period, including PSNC's actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. In addition to such information, Commission Rule R1- 17(k)(6)(c) requires that PSNC file weather normalization, sales volume data, workpapers, and direct testimony and exhibits supporting the information filed.

Witness Cronin 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 workpapers based on the twelve-month period ending March 31. Witness Cronin indicated that the Company had filed the required information. Witness Paton also indicated 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). Public Staff witness Eastwood stated that the Public Staff had reviewed the monthly deferred gas cost account reports. 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 twelve-month review period ended March 31, 2012.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 – 8

The evidence supporting these findings of fact is found in the direct testimony of PSNC witness Paton and the direct and corrected testimony of Public Staff witness Eastwood.

PSNC witness Paton's exhibits reflect demand and storage costs of $71,218,642, commodity costs of $151,341,719, and other gas costs of ($54,291,937) for a total of $168,268,424. Public Staff witness Eastwood agreed that total gas costs for the review period ended March 31, 2012, were $168,268,424. Witness Eastwood further testified that PSNC properly accounted for its gas costs during the review period. Public Staff witness Eastwood stated that the Company earned $10,159,936 of margin on secondary market transactions, including capacity release transactions and storage management arrangements, during the review period. Of this amount, $7,619,954 was credited to the All Customers Deferred Account for the benefit of ratepayers.

Public Staff witness Eastwood testified in her corrected testimony that, based on her review of the gas costs in this proceeding, the appropriate deferred account balance as of March 31, 2012, for the Sales Customers Only Deferred Account is a credit balance of $7,119,404, after the transfer of the $4,894,267 debit balance from the hedging deferred account. Witness Eastwood also stated that the appropriate balance in the All Customers Deferred Account as of March 31, 2012, is a debit balance of $23,936,586.

The Commission concludes that the appropriate balances of the Company's deferred accounts as of March 31, 2012, are a credit balance of $7,119,404 in its Sales Customers Only Deferred Account and a debit balance of $23,936,586 in its All Customers Deferred Account. The Commission further concludes that PSNC has properly accounted for its gas costs during the review period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9 – 11

The evidence for these findings of fact is contained in the testimony of PSNC witnesses Paton and Cronin and Public Staff witness Perry.

PSNC witness Paton testified that during the review period the Company incurred net costs of $4,894,267 in its Hedging Deferred Account. Public Staff witness Perry testified that these costs were composed of: Economic Losses - Closed Positions of $2,044; Premiums Paid - Closed Positions of $1,014,150; Premiums Paid - Open Positions of $3,272,610; Brokerage Fees and Commissions of $9,750; Interest on the Brokerage Account of $426; and Interest on the Hedging Deferred Account of $599,375. Witness Perry testified that the hedging costs incurred by the Company during the review period represent approximately 2.9% of gas costs or $0.13 per dekatherm (dt). Witness Perry further stated that the average monthly cost per residential customer for hedging is less than $0.70 and that PSNC's weighted average hedged cost of gas for the review period was $5.16/dt.

PSNC witness Cronin 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. Witness Cronin further testified that PSNC's hedging program meets this objective, not by attempting to out-guess the market, but rather by having financial instruments such as call options or futures in place and at a reasonable cost in order to mitigate the impact of unexpected or adverse price fluctuations to its customers.

PSNC witness Cronin stated that PSNC's hedging program currently utilizes call options in order to help control costs while still providing protection from higher prices. Witness Cronin further stated that PSNC limits the cost of the call option to no more than 10% of the underlying commodity price. Witness Cronin also stated that PSNC limits its hedging program to a twelve-month future time period in which to hedge.

Witness Cronin testified that financial hedges are limited to 25% of PSNC's estimated firm sales volume, which has been the case for some time. PSNC continues to utilize two models developed by Kase and Company to assist in determining the appropriate time and volume of hedging transactions. The total amount available to hedge is divided equally between the two models.

PSNC witness Cronin further testified that no changes were made to PSNC's hedging program during this review period. She also testified that the increased supply from unconventional shale gas plays has continued to result in lower gas prices and a reduction in price volatility during the last few years compared to that during prior periods. Witness Cronin additionally testified that shifts in production, changes in demand, impacts from weather, and changes in environmental or other regulatory policies will have an impact on natural gas prices. Therefore, PSNC continues to believe that their conservative approach to hedging is a reasonable and prudent way to provide a measure of protection to customers. Witness Cronin stated that PSNC will continue to analyze and evaluate its hedging program and implement changes to that program as warranted.

Witness Cronin testified that during the review period, NYMEX prices at the Henry Hub in Louisiana ranged from a low of $2.322/dt for the February 2012 contract to a high of $4.847/dt for the July 2011 contract. She went on to say that most of PSNC's financial hedges were structured for price protection at higher levels. Additionally, she testified that, fortunately, average natural gas prices were relatively low for the period and the purchased price protection under the hedging program was largely unneeded. Witness Cronin stated that with natural gas prices fluctuating at relatively low levels, customers ultimately benefitted from the lower cost of gas.

Witness Perry stated 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.

Based on the evidence provided above, the Commission finds that PSNC's hedging program has met the objectives of contributing to the mitigation of gas price volatility and avoiding rate shock to customers. The Commission agrees with the Public Staff that PSNC's hedging activities during the review period were reasonable and prudent and that its hedging deferred account debit balance of $4,894,267 incurred during the review period should be transferred to the Company's Sales Customers Only Deferred Account.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 – 14

The evidence for these findings of fact is found in the testimony of PSNC witness Cronin and Public Staff witness Larsen.

PSNC witness Cronin testified that approximately 50% of PSNC's market is comprised of deliveries to industrial or large commercial customers that either purchase gas from PSNC or transport gas on PSNC's system. According to witness Cronin, many of these customers have the capability to use a fuel other than gas and will use an alternate fuel when it is priced below natural gas. The remainder of the Company's sales is primarily to residential and small commercial customers. Electricity is PSNC's primary competition for these market segments.

PSNC witness Cronin further testified that the most appropriate description of PSNC's gas supply 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 Cronin indicated that security of gas supply is the first and foremost criterion. She stated that this refers to the assurance that the supply of gas will be available when needed. Witness Cronin also testified that supply security is especially important for PSNC's firm customers and is supported by PSNC's diverse portfolio of suppliers, receipt points, purchase quantity commitments, and terms.

PSNC witness Cronin testified that maintaining the necessary operational flexibility in its gas supply portfolio is the second criterion. Operational flexibility is needed to facilitate PSNC's ability to react to the unpredictable nature of weather and the changing production levels and operating schedules of PSNC's industrial customers, combined with their ability to switch to alternate fuels. She noted that while each of the supply agreements has different purchase commitments and swing capabilities, the gas supply portfolio as a whole must be capable of dealing with the monthly, daily, and hourly changes in the Company's market requirements.

In regard to the third criterion, cost of gas, PSNC witness Cronin testified that PSNC is committed to acquiring the most cost-effective supplies of gas available while maintaining the necessary security and operational flexibility to secure natural gas supply for its customers. She noted that in evaluating cost it is important to not only consider the actual commodity cost, but to also consider any fuel and transportation charges, or in the case of peaking or storage services any additional injection, withdrawal, or related fuel charges. She testified that PSNC routinely requests gas supply bids from its suppliers to help ensure PSNC is getting the most cost-effective proposals. Company witness Cronin further stated that PSNC incorporates all of these interrelated strategy components into the development of an overall gas supply portfolio to meet the needs of its customers.

Company witness Cronin testified that PSNC forecasts design-day demand to help the Company plan for capacity to meet firm customer needs that occur during extreme cold weather conditions. She further testified that PSNC design-day demand is calculated by SCANA Services Resource Planning personnel using regression analysis, incorporating five years of historical daily throughput data to forecast customer and demand growth. Witness Cronin noted that the model used by PSNC assumes a 55 heating degree day (HDD) to estimate design demand and that HDDs measure how much lower the average daily temperature is than a 65 degree Fahrenheit base temperature.

Public Staff witness Larsen testified that the Public Staff routinely performs similar calculations to determine peak day demand levels and compares that to the assets the Company has available, or is planning to have available when needed in the future, to meet that demand. The Public Staff uses the review period data of customer usage and HDDs. Witness Larsen further testified that base load (usage that does not fluctuate with weather) plus a usage per HDD factor is developed, and the projected peak day demand is calculated. He added that the assumption in developing a peak day demand is 55 HDDs, which is the accepted peak coldest day for the State of North Carolina.

PSNC witness Cronin stated that the majority of PSNC's interstate pipeline capacity is obtained from Transcontinental Gas Pipe Line 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 deliver 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; and East Tennessee Natural Gas, LLC. In addition, PSNC has storage service agreements with Dominion Cove Point LNG, LP; Saltville Gas Storage Company, LLC; and Pine Needle LNG Company, LLC.

Company witness Cronin additionally described in her testimony PSNC's Cary LNG facility. She stated that this facility is located in Cary, North Carolina and can liquefy natural gas at a rate of approximately 3,300 dt/day, can store up to 1,000,000 dt of LNG, and can inject approximately 100,000 dt/day of re-vaporized natural gas into PSNC's system. Witness Cronin testified that most of PSNC's liquefaction activities take place during the spring so that the desired LNG storage level is reached prior to the beginning of the winter heating season.

PSNC witness Cronin testified that PSNC did not contract for any additional pipeline capacity or storage services during the review period. She noted, however, that PSNC has recently experienced 1-2% customer growth on its system and its latest forecast indicates that additional capacity will be needed by the winter of 2013-2014 to respond to firm customer demand on a design day. PSNC witness Cronin presented this in her Exhibit 1. Company witness Cronin further testified that PSNC was currently considering plans to satisfy these projected design-day needs through the recently announced Transco Atlantic Access Project with a proposed in-service date of December 2015. Witness Cronin testified that in the meantime, PSNC could take short-term measures, such as making greater use of marketer contracts and back-haul capabilities, to meet incremental capacity needs.

Public Staff witness Larsen testified that the results of the analysis done by the Public Staff are comparable to PSNC's levels in Cronin Exhibit 1. Witness Larsen further testified that the Shipper Purchase Agreements (also referred to as Curtailment Gas Purchase Agreements) that are listed on this exhibit, one of which was filed and approved in Docket No. G-5, Sub 400A, were reviewed by the Public Staff in prior Annual Review of Gas Costs (ARGC) proceedings. Witness Larsen noted that while the Public Staff agrees with utilizing this resource it should not be relied upon as a firm asset, as its availability is determined by the performance of the poolers on PSNC's system and therefore should not be included as an available resource for peak day planning purposes. Witness Larsen further noted that the Public Staff has also filed comments regarding peak-day demand and assets to meet that demand in Docket No. G-100, Sub 91, Investigation Regarding Competition for Additional Natural Gas Service Agreements, which is a generic docket involving all LDCs.

Company witness Cronin additionally testified that there had been changes to PSNC's pipeline capacity and storage services during the review period. She stated that effective May 1, 2011, daily withdrawal entitlements for the rate schedule WSS-Open Access storage service, which PSNC receives from Transco's Washington Storage Field, were reduced by 3,461 dt/day as a result of a partial abandonment approved by the Federal Energy Regulatory Commission (FERC) on March 30, 2011. Witness Cronin noted that this reduction did not operationally impact service to the PSNC system.

PSNC witness Cronin testified that on September 29, 2011, Transco filed an application with FERC to abandon four caverns and to partially abandon service from three other caverns located at Transco's Eminence Storage Field. She stated that upon FERC approval, PSNC's service agreements will be amended to reflect the revised storage and capacity quantities. She added that as of June 1, 2012, Transco's application was still pending before the FERC. Witness Cronin also testified that as a result of the partial abandonment, PSNC anticipates that its maximum storage quantity will be reduced by 315,493 dt to 640,221 dt and its daily withdrawal quantities will be reduced by 19,219 dt/day to 76,262 dt/day, along with an associated decrease in the charges PSNC pays for this service. Witness Cronin stated that ESS, like WSS, does not affect deliverability to PSNC's citygate.

Witness Cronin further testified that PSNC's firm transportation (FT) capacity is supported by a gas supply portfolio of long-term supply contracts with a variety of suppliers, including baseload contracts that provide a fixed volume of gas each day, take-or-release contracts that provide the flexibility to modify the volumes delivered on a monthly basis, no-notice contracts that provide the flexibility to increase or decrease volumes on a daily basis, and spot market contracts that provide for daily purchase of gas. According to witness Cronin, PSNC had approximately 237,000 dt/day under term contracts with five producers and seven independent marketers as of November 1, 2011, the beginning of the winter heating season for the period under review. She testified that the contracts all have provisions to ensure that the prices paid are market sensitive.

PSNC witness Cronin testified that the gas supply and capacity portfolio that the Company has developed provides it the flexibility to meet PSNC's market requirements in a secure and cost-effective manner.

In addition, PSNC witness Cronin testified to the following activities that PSNC has engaged in to lower gas costs while maintaining security of supply and delivery flexibility:

1. PSNC continues to evaluate various firm transportation and storage capacity options and enter into agreements to meet future peak-day and seasonal durational requirements.

2. PSNC continues to optimize the flexibility available within its supply and capacity contracts to realize their value.

3. PSNC participated in matters before the FERC whose actions could impact PSNC's rates and services.

4. PSNC has continued to work with its industrial customers to facilitate transportation of customer-owned natural gas.

5. PSNC routinely communicates directly with customers, suppliers, and other industry participants, and actively monitors developments in the industry.

6. PSNC has frequent internal discussions concerning gas supply policy and major purchasing decisions.

7. PSNC utilizes deferred gas cost accounting to calculate the Company's benchmark cost of gas to provide a smoothing effect on gas price volatility.

8. PSNC conducts a hedging program to help mitigate price volatility.

Public Staff witness Larsen stated that he 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. Witness Larsen further testified that PSNC secures its gas supply at monthly index market prices and engages in hedging of a portion of its firm market gas supply.

The Commission concludes that the gas costs incurred by PSNC during the test period ended March 31, 2012, were reasonable and prudently incurred and that the Company should be permitted to recover 100% of its prudently incurred gas costs. However, the Commission notes the following information that it wants to receive from PSNC in future filings.

In the Commission’s January 25, 2012 Order on Annual Review of Gas Costs (Piedmont Order), in Piedmont Natural Gas Company, Inc.’s (Piedmont’s) ARGC in Docket No. G-9, Sub 595, two related issues concerning the addition of pipeline and storage capacity were addressed: (1) the manner in which an LDC determines the amount of capacity required and, (2) the manner in which the LDC obtains that capacity.

In the Piedmont Order, the Commission discussed the law mandating an ARGC and the importance of reviewing each LDC’s capacity additions in the ARGC. The Commission pointed out that the same law that allowed it to include pipeline and storage capacity costs as “gas costs” to be passed through outside of a rate case also mandated an ARGC for each LDC. In that Piedmont Order, the Commission commented, “This highlights the importance of reviewing the manner in which the LDC goes about securing the appropriate amount of capacity to meet the needs of its customers.”

Ordering Paragraph 4 of the Piedmont Order directed Piedmont to file in its next ARGC a detailed description of its gas capacity planning. Explicitly, the Commission ordered Piedmont to:

> …file with the Commission, in addition to the information required by Rule R1-17(k)(6)(c), a detailed description of its current capacity levels and its planning process to secure future capacity. Information filed shall include design day demand calculations, forecasted load duration curves, projection of capacity additions and supply changes and customer load profile changes. Detailed underlying assumptions shall be included.

In order for the Commission to more fully understand PSNC’s capacity addition process, the Commission finds good cause to require PSNC to file this same information in its future ARGCs.

Ordering Paragraph 5 of the Piedmont Order ordered Piedmont to inform the Commission well in advance of any plans to contract for interstate pipeline and storage capacity and to present to the Commission at that time any alternative projects evaluated. The Commission specified that this notification shall be far enough in advance so that alternative projects can be considered. On March 14, 2012, in the Commission’s Order Denying Motion for Clarification or Rehearing, the Commission stated that it expects this same timely information from all regulated gas utilities. Further on April 2, 2012, the Commission opened Docket No. G-100, Sub 91, Investigation Regarding Competition for Additional Natural Gas Service Contracts. PSNC is a party to that docket.

On December 7, 1999, the Commission issued its Order Approving Merger and Issuance of Securities in Docket No. G-5, Sub 400. Regulatory Condition 35 in that Order stated:

> PSNC shall utilize competitive solicitation procedures to determine future long-term sources of interstate pipeline capacity and supply. The determination of the appropriate source(s) for the interstate pipeline capacity and supply shall be made by PSNC on the basis of the benefits and costs of such source(s) specifically to PSNC's gas customers.

Pending further action by the Commission in Docket No. G-100, Sub 91, the Commission concludes that Regulatory Condition 35 of the Order in Docket No. G-5, Sub 400 adequately addresses the Commission’s concerns. However, the Commission directs that in future ARGC’s PSNC should fully discuss the competitive solicitation procedures that it undertook to acquire any additional capacity and supply during the review period of that ARGC.

In Docket Nos. G-5, Sub 414 and 421, the Commission raised questions about PSNC’s participation in matters before regulatory and governmental agencies whose actions could reasonably impact PSNC’s rates and services. These questions came in the context of PSNC’s participation as an equity owner in a FERC-regulated entity with Transco as a business partner. The Commission’s intent was to scrutinize PSNC’s performance in such matters carefully. In the instant docket, PSNC Witness Cronin’s testimony included a list of FERC dockets in which the Company acted to become a party, with no description of those proceedings nor any comment as to the position PSNC had taken in each of them. In future annual review filings, the Commission requests that the Company file a description of the FERC proceedings in which it participated and make comments regarding the position that PSNC has taken in each of them.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this finding of fact is found in the testimony of PSNC witness Paton and Public Staff witness Larsen.

Company witness Paton testified that the Company was proposing temporary rate increments applicable to the All Customers Deferred Account and a temporary rate decrement applicable to the Sales Customers Only Deferred Account.

Public Staff witness Larsen testified that the Public Staff agrees with PSNC’s calculated temporary rate decrement applicable to the Sales Customers Only Deferred Account and the temporary rate increments applicable to the All Customers Deferred Account contained in Company witness Paton's testimony and exhibits.

Based upon the foregoing, the Commission concludes that it is appropriate for PSNC to remove all temporary rate increments and decrement that were implemented in Docket No. G-5, Sub 524, and implement the temporary rate increments and decrement as proposed by Company witness Paton and agreed to by Public Staff witness Larsen.

IT IS, THEREFORE, ORDERED as follows:

1. That PSNC's accounting for gas costs for the twelve-month period ended March 31, 2012, is approved;

2. That the gas costs incurred by PSNC during the twelve-month period ended March 31, 2012, were reasonably and prudently incurred, and PSNC is hereby authorized to recover 100% of these gas costs as provided herein;

3. That PSNC shall remove the existing temporary rate increments and decrement that were implemented in PSNC's last ARGC proceeding, and implement the temporary rate increments and decrement proposed by Company witness Paton and agreed to by Public Staff witness Larsen in the instant docket, effective for service rendered on and after November 1, 2012;

4. That PSNC shall, in its next ARGC, file with the Commission a detailed description of its gas capacity planning as discussed in the body of this order;

5. That PSNC shall file with the Commission, in addition to the information required by Rule R1-17(k)(6)(c), a detailed description of its current capacity levels and its planning process to secure future capacity. Information filed shall include design day demand calculations, forecasted load duration curves, projection of capacity additions and supply changes and customer load profile changes. Detailed underlying assumptions shall be included;

6. That PSNC in future ARGCs shall fully discuss the competitive solicitation that it undertook to acquire any additional capacity and supply during the review period of that ARGC;

7. That in future annual review filings, PSNC shall file a description of the FERC proceedings in which it participated and make comments regarding the position that PSNC has taken in each of them; and

8. That PSNC shall give notice to its customers of the rate changes allowed in this Order.

ISSUED BY ORDER OF THE COMMISSION
This the _9th__day of October, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

eb100812.01

DOCKET NO. G-9, SUB 607

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Piedmont Natural Gas Company,	)	
Inc., to Construct Pipeline Facilities in	)	ORDER AUTHORIZING
Mecklenburg, Iredell and Cabarrus Counties	)	CONSTRUCTION OF PIPELINE

BY THE COMMISSION: On February 6, 2012, Piedmont Natural Gas Company, Inc. (Piedmont), filed an application with the Commission for authority to construct and operate natural gas pipeline facilities in portions of Mecklenburg, Iredell, and Cabarrus Counties pursuant to Commission Rule R6-61 (Application). The Application states that on April 14, 2010, Piedmont entered into a Natural Gas Pipeline Construction and Redelivery Services Agreement (Agreement) with Progress Energy Carolinas, Inc. (PEC), whereby Piedmont agreed to construct new natural gas transmission facilities in order to provide redelivery service to serve PEC's planned expansion of its combined cycle electric generation facilities at the Sutton Combined Cycle Station in New Hanover County, North Carolina (Sutton Combined Cycle Station) (the proposed pipeline facilities are hereinafter referred to as "the Sutton Project"). According to the Application, the Sutton Project requires the development of two new compressor stations, the construction of 5.8 miles of 30-inch pipeline looping on the upstream side of Piedmont's existing Cabarrus compressor station and approximately 127 miles of 20-inch diameter pipe from the end of its existing 30-inch line in Mecklenburg County to the Sutton Combined Cycle Station. The Agreement was approved by the Commission on May 11, 2010, in Docket No. G-9, Sub 579.

The Sutton Project will require Piedmont to install high pressure gas transmission lines, natural gas compression facilities, measurement tools, pressure regulating equipment, and other associated equipment in order to provide PEC the hourly and daily firm redelivery service provided for in the Agreement. In order to connect with the Transco delivery point in Iredell County that will provide gas for redelivery to the Sutton Combined Cycle Station, approximately 8 miles of high-pressure transmission line cross in and out of portions of Iredell, Cabarrus, and Mecklenburg Counties that fall within the franchised service territory of Public Service Company of North Carolina, Inc. (PSNC), as shown on the map attached to the Application as Exhibit A.

According to the Application, no service to the public will be offered or provided by Piedmont from facilities located in PSNC's service territory, and no change in Piedmont's and PSNC's respective service territory rights will be effected by the relief sought by Piedmont.

Commission Rule R6-61 requires a natural gas local distribution company to obtain Commission approval prior to constructing or operating a pipeline outside of its designated territory. In the Application, Piedmont requests authorization to construct and operate transmission facilities within PSNC's service territory necessary to provide redelivery service to

PEC. Piedmont states that the Sutton Project is economically and financially feasible, and will not be wastefully duplicative of existing or proposed construction by any other supplier of natural gas in the State, will not constitute an unfair burden upon Piedmont's customers in this State, and is in the public interest generally.

During the period of February 2012 through March 2012, copies of correspondence sent by Piedmont and Davidson College to the North Carolina Department of Environment and Natural Resources and the United States Army Corps of Engineers were filed in the docket. Davidson College, which is located within Mecklenburg and Iredell Counties, objected to Piedmont's proposed pipeline route.

On February 17, 2012, PSNC filed a petition to intervene, which was granted by the Commission on March 2, 2012.

On March 5, 2012, a copy of PSNC's correspondence to Piedmont, which indicated that PSNC was undergoing its review of Piedmont's Application, was filed in the docket.

On July 2, 2012, PSNC filed a letter with the Commission stating that PSNC and Piedmont have discussed the construction and routing of the proposed pipeline facilities that are the subject of Piedmont's Application, Piedmont has recently provided PSNC with a revised route for the facilities, and that PSNC has no objections to Piedmont's proposed facilities in PSNC's territory that are to be located in the route as currently revised.

On September 5, 2012, Piedmont filed a letter with the Commission stating that the pipeline route has been revised to the satisfaction of both Davidson College and Piedmont. Piedmont also filed a revised map illustrating the revised pipeline route. This map is intended to replace the map filed as Exhibit A to the Application.

The Public Staff presented this matter at the Commission's Regular Staff Conference on September 17, 2012, and stated that it had reviewed the application and information provided by Piedmont in response to a Public Staff data request. The Public Staff recommended that the Commission issue an order granting Piedmont authority to construct the proposed pipeline without prejudice to the right of any party to challenge in a subsequent proceeding the appropriate ratemaking treatment to be accorded the pipeline facilities.

On September 18, 2012, Piedmont filed a letter in the docket to clarify that the revised pipeline route shown in Piedmont's September 5, 2012 filing is the same route provided to PSNC to which PSNC indicated it had no objections in its July 2, 2012 filing in this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That Piedmont's Application for authority to construct two new compressor stations, 5.8 miles of 30-inch pipeline looping on the upstream side of Piedmont's existing Cabarrus compressor station, and approximately 127 miles of 20-inch diameter pipe from the end of its existing 30-inch line in Mecklenburg County to PEC's Sutton Combined Cycle Station in New Hanover County is hereby granted.

2. That Piedmont shall comply fully with the Commission's Rules in the operation of, and provision of service from, the pipeline for which approval has been granted herein.

3. That this authority to construct the proposed pipeline is without prejudice to the right of any party to challenge in a subsequent proceeding the appropriate ratemaking treatment to be accorded the proposed pipeline.

ISSUED BY ORDER OF THE COMMISSION.
This the ___18th___ day of September, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

Commissioner William T. Culpepper, III, did not participate.

Bh091812.15

DOCKET NO. G-9, SUB 612

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Piedmont Natural Gas	)	ORDER AUTHORIZING
Company, Inc., to Construct Pipeline Facilities	)	CONSTRUCTION OF PIPELINE
in Wake County	)	

BY THE COMMISSION: On April 16, 2012, Piedmont Natural Gas Company, Inc. (Piedmont), filed an application with the Commission for authority to construct and operate natural gas pipeline facilities in Wake County pursuant to Commission Rule R6-61. The application indicates that Piedmont proposes to construct one new compressor station and 38 miles of 20-inch diameter pipe from the end of the Cardinal Pipeline in Clayton, Wake County, to the Wayne County Combined Cycle Combustion Turbine Plant (Wayne Project) of Progress Energy Carolinas, Inc. (PEC). Piedmont stated that on October 21, 2009, it had entered into a Natural Gas Pipeline Construction and Redelivery Services Agreement (Agreement) with PEC, which was approved by the Commission on May 11, 2010, in Docket No. G-9, Sub 572.

The Wayne Project will require Piedmont to install high pressure gas transmission lines, natural gas compression facilities, measurement tools, pressure regulating equipment, and other associated equipment in order to provide PEC the hourly and daily firm redelivery service provided for in the Agreement. In order to connect with the new Clayton compressor station in Wake County that will provide gas for redelivery to the Wayne Project, approximately 2,526 feet of high-pressure transmission line will be built in the franchised territory of Public Service Company of North Carolina, Inc. (PSNC).

Commission Rule R6-61 requires a natural gas local distribution company to obtain Commission approval prior to constructing or operating a pipeline outside of its designated territory, and in this case facilities will be constructed in PSNC's territory. Piedmont states that the proposed pipeline is necessary for Piedmont to deliver the necessary quantities of natural gas to the generating facilities PEC intends to construct in Wayne County.

The Public Staff presented this matter at the Commission's Regular Staff Conference on May 29, 2012, and stated that it had reviewed the application and information provided by Piedmont in response to a Public Staff data request, and had contacted PSNC regarding this docket. The Public Staff stated that PSNC indicated that it has no objection to Piedmont's proposed route.

The Public Staff recommended that the Commission issue an order granting Piedmont authority to construct the proposed pipeline without prejudice to the right of any party to challenge in a subsequent proceeding the appropriate ratemaking treatment to be accorded the pipeline facilities.

IT IS, THEREFORE, ORDERED as follows:

1. That Piedmont's application for authority to construct one new compressor station and 38 miles of 20-inch diameter pipe from the end of the Cardinal Pipeline in Wake County to the Wayne County Combined Cycle Combustion Turbine Plant is hereby granted.

2. That Piedmont shall comply fully with Commission Rules R6-60, R6-61, and R6-62 in the operation of, and provision of service from, the pipeline for which approval has been granted herein.

3. That this authority to construct the proposed pipeline is without prejudice to the right of any party to challenge in a subsequent proceeding the appropriate ratemaking treatment to be accorded the proposed pipeline.

ISSUED BY ORDER OF THE COMMISSION.
This the _31st_ day of May, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioner William T. Culpepper, III, did not participate.

Bh053112.05

DOCKET NO. G-39, SUB 28

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, December 4, 2012, 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 and Susan W. Rabon

APPEARANCES:

For Cardinal Pipeline Company, LLC:

Robert W. Kaylor, P.A., 3700 Glenwood Avenue, Suite 330, Raleigh, North Carolina 27612

For the Using and Consuming Public:

Gina C. Holt, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On July 24, 2012, 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 July 24, 2012, Cardinal filed a separate Request for Waivers of certain Commission requirements pertaining to the general rate case. Specifically, Cardinal requested waivers of "Item 25 – Accounts Payable" and "Item 26 – Lead/Lag Study" required by Commission Form G-1, General Rate Case Requirements, and waiver of Commission Rule R1-17(d), regarding notice to its customers in local newspapers. On August 20, 2012, the Commission issued an Order granting the requested waivers.

On August 31, 2012, Cardinal filed its verified application for an adjustment in its rates and charges for natural gas service (Application). Included with the Application were the data required by NCUC Form G-1, and the direct testimony and exhibits of Charlotte Hutson, Manager of Cost of Service and Rate Design for Cardinal Operating Company, LLC as operator of Cardinal, and Michael J. Vilbert, Ph.D., an economist and a Principal of The Brattle Group.

On September 26, 2012, the Commission issued its Order Setting Investigation and Hearing, Suspending Proposed Rates, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Notice.

On October 19, 2012, Public Service Company of North Carolina, Inc. (PSNC) filed a Petition to Intervene, which the Commission granted on October 24, 2012.

On November 13, 2012, Piedmont Natural Gas Company, Inc. (Piedmont) filed a Petition to Intervene, which the Commission granted on November 15, 2012.

On November 15, 2012, the Public Staff filed a Motion for Extension of Time to File Testimony, which the Commission granted on November 15, 2012.

On November 16, 2012, Cardinal, the Public Staff, Piedmont, and PSNC, herein referred to as the "Stipulating Parties," filed a Joint Stipulation in settlement of all aspects of this proceeding.

On December 4, 2012, the case came on for hearing as scheduled in Raleigh. No public witnesses appeared. At the hearing, Cardinal and the Public Staff jointly presented the Stipulation to the Commission.

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 its Application in this docket, Cardinal sought a general decrease in its rates and charges in the amount of $3,313,561 per year.

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 June 30, 2012.

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 in annual revenues of $4,889,402.

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, all as described and set forth in Paragraph 2 and Exhibit A of the Stipulation, is 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 for use in this docket.

11. Cardinal's depreciation rates filed on October 26, 2011, in Docket No. G-39, Sub 23, and accepted by the Commission for compliance with Commission Rule R6-80 on January 24, 2012, are reasonable and appropriate for use in this proceeding.

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 for use in this docket.

13. The allocation methodology employed by Cardinal in determining the cost of service applicable to each zone and the specific rates is just and reasonable.

14. The zonal allocation factors, as set forth in Exhibit A of the Stipulation, are just and reasonable.

15. The schedule of rates shown in Exhibit B of the Stipulation is just and reasonable.

16. Cardinal's proposed Electric Power Cost Adjustment Provision to recover the cost of electric power at Compressor Station 161, as set forth in Exhibit C of the Stipulation, is just and reasonable.

17. Cardinal's agreement to file its next general rate case no later than March 15, 2017, and to provide the Public Staff 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.

18. 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 Commission's records as a whole. These findings are primarily jurisdictional 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 June 30, 2012. The Stipulation is based upon the test period utilized by Cardinal, and 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 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 Hutson, and the Stipulation.

Hudson Exhibit 8 indicates that Cardinal filed for a revenue decrease of $3,313,561. 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 $16,700,372, which represents a $4,889,402 decrease from the total annual cost of service and revenue requirement as of June 30, 2012, the end of the 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.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

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 to the Stipulation.

Cardinal's original cost rate base used and useful in providing service in North Carolina of $81,381,551, consisting of gas plant-in-service of $151,310,514 and working capital of $295,546 reduced by accumulated depreciation of $39,321,514 and accumulated deferred income taxes of $30,902,995, is the result of negotiations among the parties and is not opposed by any party. The Commission concludes that the above amounts are appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The total annual cost of service and revenue requirement under Cardinal's stipulated proposed rates is $16,700,372 and is set forth in Paragraphs 3 and 4 and Exhibit A of the Stipulation. This represents a $1,575,841 decrease from the total annual cost of service and revenue requirement filed by Cardinal in this proceeding. 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 concludes that the above amounts are appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

This finding is supported by the Application and the direct testimony of Company witness Hutson, who references the Company's latest Depreciation Rate Study filing, in Docket No. G-39, Sub 23. In that docket, the Commission issued an order on January 24, 2012, 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 these depreciation rates are reasonable and appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

Cardinal's reasonable operating expenses, including actual investment currently consumed through reasonable actual depreciation, is set forth in Exhibit A of the Stipulation. The Stipulating Parties agree that O&M expenses should be decreased by $494,842 to remove electric power expenses, and to adjust the portion of total labor-related costs charged to O&M expense accounts, odorant expense, O&M compressor station maintenance expense, property insurance, and non-recurring expenses. After reflecting the O&M expense adjustments, the Stipulating Parties agree that the annual level of O&M expenses to be used in this proceeding is $2,265,547. The Stipulating Parties agree that depreciation expense should be decreased by $61,691 to reflect the adjustment for actual plant in service as of September 30, 2012, and that the annual level of depreciation expense to be used in this proceeding is $3,878,666. The Stipulating Parties agree that taxes other than income should be adjusted for property and payroll taxes based on the aforementioned adjustments to plant in service and payroll. The Stipulating Parties agree that the annual level of taxes other than income to be used in this proceeding is $734,057. The Stipulating Parties agree that income taxes should be determined using the North Carolina state income tax rate of 6.9% and the federal income tax rate of 35%, and that the composite state and federal income tax rate is 39.485%.

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 concludes that the above amounts are appropriate for use in this docket.

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

These findings are supported in Paragraph 3 and Exhibit A of the Stipulation. The Stipulating Parties agree to the allocation methodology employed by Cardinal in determining the cost of service applicable to each zone and the specific rates. The Stipulating Parties also agree 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 concludes that the zonal allocation factors as set forth in Exhibit A of the Stipulation are appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

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 Stipulating Parties agree that the revenues generated by the rates shown on Exhibit B of the Stipulation will produce the revenue requirement established in this Stipulation. The Commission concludes that the rates as set forth on Exhibit B of the Stipulation are appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The Support for this finding is contained in Paragraph 5 and Exhibit C of the Stipulation. The Stipulating Parties agree to Cardinal's proposal to implement an Electric Power Cost Adjustment Provision to recover the cost of electric power at Compressor Station 161 as shown on the revised tariff attached as Exhibit C. The effective date of the Electric Power Cost Adjustment Provision shall be January 1, 2013, or, if a later date is approved by the Commission, it shall be coincidental with the Effective Date of Rates in the Commission's order approving the rates set forth in Paragraph 7 of the Stipulation, as agreed to by all parties. No party objects to this proposal. The Commission concludes that this proposal is just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

Consistent with Paragraph 6 of the Stipulation, Cardinal agrees to file its next general rate case no later than March 15, 2017. Cardinal also agrees to provide the Public Staff 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. Consistent with the Stipulation, the Stipulating Parties agree not to initiate a show cause proceeding for Cardinal before its next general rate case filing date. These findings are not contested by any party. The Commission concludes that this proposal is just and reasonable in this docket and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

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 Cardinal is hereby authorized to adjust its rates and charges in accordance with the Stipulation attached to this order as Attachment A effective for service rendered on and after the first day of the first month following the date of this order, and the Stipulation is approved.

2. That Cardinal shall file rates to comply with ordering Paragraph 1 of this order within ten (10) days from the date of this order.

3. That the depreciation rates filed by Cardinal on October 26, 2011, in Docket No. G-39, Sub 23, are approved.

4. That Cardinal shall implement an Electric Power Cost Adjustment Provision effective as of the first day of the first month following the date of this order.

5. That Cardinal shall file its next general rate case no later than March 15, 2017, and shall also provide the Public Staff with a rough outline of the rate case thirty days before filing the rate case.

ISSUED BY ORDER OF THE COMMISSION.
This the __6th__ day of _December__, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

wg120612.01

DOCKET NO. SP-729, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of W.E. Partners I, LLC, for Registration of a New Renewable Energy Facility	))))	ORDER ON REQUEST FOR DECLARATORY RULING AND NOTICE OF INTENT TO REVOKE REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

BY THE COMMISSION: On July 26, 2010, the Commission issued an Order Accepting Registration of New Renewable Energy Facility pursuant to an application made on June 17, 2010, by W.E. Partners I, LLC (WEP). WEP had filed a request to register a new renewable energy facility located in Cofield in Hertford County, North Carolina. WEP's filing stated that its proposed facility would be a cogeneration facility with two 29 MMBtu/hour wood waste-fired boilers and a 375 kW steam turbine electric generator. WEP stated further that electricity produced by the facility would be sold to Dominion North Carolina Power (Dominion) and that steam extracted from the turbine after electric power generation would be provided to Perdue Agribusiness, Inc. (Perdue), for its grain elevator operations. In its July 26, 2010 Order Accepting Registration, the Commission required WEP to participate in a renewable energy certificate (REC) tracking system and to regularly provide the system with metered generation data and thermal energy production data for the issuance of RECs.

On March 8, 2012, WEP filed a supplement to registration and request for declaratory ruling. In its filing, WEP stated that subsequent to its 2010 registration request it had changed its facility configuration and operations. WEP stated that it had increased the size of its electric generator from 375 kW to 495 kW. WEP also stated that it no longer plans to sell electricity to Dominion. WEP stated that its steam host, Perdue, uses less steam than had been anticipated, thus reducing the amount of electricity generated by the facility. WEP stated that it is generating 190 kW to 220 kW of power, and that almost all of that power (180 kW to 220 kW) is required to run the facility, leaving very little power available for other uses. WEP stated that it would be cost-prohibitive to install the interconnection equipment necessary to sell the facility's small amount of residual electric output. WEP stated further that "all electrical energy generated at WEP's facility is used at that facility." WEP requested that the Commission issue a declaratory ruling finding that its biomass-fueled facility is a combined heat and power system that remains eligible to earn RECs for its thermal energy production.

On April 2, 2012, the North Carolina Association of Professional Loggers (NCAPL) and the North Carolina Sustainable Energy Association (NCSEA) jointly filed comments supporting WEP's request. They stated that WEP's biomass-fueled facility is achieving the overriding goals of North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) because using woody biomass as a fuel can (1) diversify the State's traditional nonrenewable fuel portfolio; (2) provide greater security through the use of indigenous resources; and (3) encourage private investment. The joint submittal stated, that "NCAPL and NCSEA support issuance of a declaratory ruling that the useful thermal energy generated at WEP's facility net of station load qualifies for thermal RECs."

On May 3, 2012, the Public Staff filed its response to WEP's supplement and declaratory order request. The Public Staff opposed WEP's request and argued that WEP should demonstrate that the facility delivers some power to an electrical supplier and thereby earns electric RECs in order for its thermal energy to be eligible for RECs. The Public Staff asserted that G.S. 62-133.8 placed the duty to comply with REPS on electric power suppliers and established a mechanism for recovering the incremental costs associated with REPS compliance through a charge on electric ratepayers. According to the Public Staff, "inherent in this structure is the principle that any facility that qualifies for RECs should provide a benefit to electric ratepayers by delivering at least some power generated by a renewable energy resource to an electric power supplier and displacing generation using a non-renewable resource." Further, citing the NC-RETS Operating Procedures, the Public Staff argued that the definition of station service, commonly referred to as station power, must be considered a determining factor for both electric and thermal energy to be deemed eligible for RECs.

In the Public Staff's view, all of the electric output of WEP's facility will be used for station service, making it ineligible for electric RECs. In addition, the Public Staff cited the Commission's March 13, 2012 Order in Dockets No. SP-100, Sub 9 and SP-967, Sub 0 which state that a combined heat and power (CHP) facility "must be an electricity generating facility in a 'real sense,' and not simply a boiler masquerading as a CHP." That Order stated that "some electric power must be generated in excess of station power" in order for the facility to qualify as a combined heat and power facility, and hence be eligible for thermal RECs. The Public Staff noted that WEP asserts that some of its electric output, about 10 kW, is used for lighting, office equipment, heating, and air conditioning rather than for station service. The Public Staff disagreed that this output would be eligible for RECs, citing the fact that WEP delivers no electricity to an electric power supplier. Finally, the Public Staff recommended that the Commission accept WEP's supplement to registration, but deny the request for a declaratory ruling that the facility's useful thermal energy qualifies for thermal RECs.

On May 18, 2012, WEP filed reply comments to the Public Staff's response. WEP stated that there is no statutory requirement that the electricity generated by a renewable energy facility be sold to a third party in order for its thermal energy to be eligible for RECs. Further, WEP argued that its biomass-fueled facility, as defined by statute, is a new renewable energy facility because it uses a renewable energy resource. WEP explained that its biomass-fueled facility displaced electric generation from non-renewable resources because Perdue has been able to put its own fossil-fueled boiler on standby and thereby reduce its own electric demand by about 110 kW since WEP's facility came online. "Thus, while WEP is not providing electricity to Perdue, the net effect of bringing the WEP facility online is that Perdue's demand for electrical energy has been reduced ...." Therefore, WEP asserted that its facility addresses the overarching objective of REPS.

In its reply comments WEP also opposed the Public Staff's position that the definition of station service be a determining factor relative to whether its thermal energy is eligible for RECs. In that regard, WEP argued that its facility's approval as a new renewable energy facility pre-dated the Commission's January 31, 2011 adoption of the NC-RETS Operating Procedures in which station service is defined and excluded from REC issuance. WEP asserted that because the prohibition on issuing RECs for power used for station service was not yet established when WEP filed its registration application, that prohibition should not be a factor in the

Commission's decision at this time. Further, WEP contended that Commission Rule R8-66(b)(1)(iii), by requiring an applicant to state "whether it produces electricity, useful thermal energy, or both," shows that the requirement of supplying both electric generation and thermal energy was not the intention of the Commission. Finally, WEP requested that the Commission issue a declaratory ruling that the useful thermal energy generated at its biomass-fueled facility remains eligible to earn RECs.

DISCUSSION AND CONCLUSIONS

WEP's request and the Public Staff's response raise several issues. First is the issue of station service and whether the definition and prohibition in the NC-RETS Operating Procedures should apply to WEP's facility. WEP's submittals state that WEP's facility produces up to 220 kW of electricity and immediately consumes almost all of that electrical power, with a small amount being used on site for lighting, heating, cooling and ventilation. Therefore, the facility's only energy product is the steam that it provides to Perdue.

The Commission's July 1, 2010 Order Adopting Interim Operating Procedures for REC Tracking System, issued in Docket No. E-100, Sub 121, defined station service as follows:

> Station Service is the portion of electricity or thermal energy produced by a Renewable Energy Facility that is immediately consumed at that same facility in order to power the facility's pumps, etc., or to process fuel. Such energy is not eligible for issuance of Certificates.

This policy is intended to ensure that renewable energy facilities produce more electric energy than they consume. Only the net output, that is, the output that is available to serve other needs beyond operating the facility, is eligible for the issuance of RECs.

Further clarifying the importance of electricity production in excess of station service, Commission Rule R8-66(b)(1)(viii) requests that facilities already in operation provide the amount of energy produced "net of station use" in their initial registration statement. WEP contends that Commission Rule R8-66(b)(1)(iii), by requiring an applicant to state "whether it produces electricity, useful thermal energy, or both," shows that the Public Staff's argument, that the facility must produce and supply both electricity and thermal energy, adds a non-existent requirement. However, Commission Rule R8-66(b)(1)(iii) is not only applicable to CHP facilities, but rather to all renewable energy facilities, including solar thermal facilities, which, unlike a CHP facility, are not required to produce electricity by statute.

WEP's contention, that the application of rules requiring electricity production to exceed station service to be registered as a new renewable energy facility constitutes an unfair retroactive application of new rules, is without merit. In its request, WEP stated that its initial registration statement advised the Commission that "the Net Electricity (electricity in excess of internal plant requirements) … would be sold to Dominion North Carolina Power." In addition, WEP's request stated that "the quantity of electric RECs projected in WEP's registration statement was based on the estimated gross electrical output of the facility as then planned." However, the initial registration statement does not identify that only "Net Electricity" will be sold to Dominion North Carolina, stating only that the facility will "provide electricity to

Dominion Power." In addition, the initial registration statement estimates the expected RECs generated as 2,098 electric RECs, citing the definition in G.S. 62.133.8(a)(6), that such electricity or energy is "supplied by a renewable energy facility," in the explanation of the calculation. Based on the initial registration statement there was no basis for the Commission to conclude that WEP would not be producing electricity in excess of station service. This new information constitutes a significant change in WEP's registration statement, and, thus, the Commission must reconsider the request under currently established rules.

Furthermore, the policy that only the net output is eligible for the issuance of RECs pre-dates the Commission's July 26, 2010 Order Accepting Registration of WEP's facility. G.S. 62.133.8(a)(6) requires that RECs be derived from "electricity or equivalent energy" that is "supplied by a renewable energy facility." Gross electricity used to power the facility itself cannot be considered electricity "supplied by a renewable energy facility" as required for the issuance of RECs by G.S. 62.133.8(a)(6).

WEP contends that its behind the meter electric output of about 10 kW used for lighting, office equipment, heating, and air-conditioning is net output in excess of station service. The Commission disagrees. The onsite electric needs would not exist but for the generator. The Commission considers this type of behind the meter use to be station service as it "is immediately consumed at that same facility in order to power the facility's pumps, etc., or to process fuel." The 10 kW in dispute may not directly "power the facility's pumps" or "process fuel;" however, the inclusion of "etc." in the definition indicates that station service broadly includes other uses of electricity at the generating facility, not solely the two specifically listed. The Commission interprets this definition to encompass all electric demand consumed at the generation facility that would not exist but for the generation itself, including, but not limited to, lighting, office equipment, heating, and air-conditioning at the facility. This interpretation is consistent with the Federal Energy Regulatory Commission's definition of station service. PJM Interconnection, LLC, 94 FERC ¶ 61,251 at 61,889 (2001), clarified and reh'g denied, 95 FERC ¶ 61,333 (2001) (defining "station power" to include the "electric energy used for the heating, lighting, air-conditioning, and office equipment needs of the buildings on a generating facility's site"); see also, Occidental Geothermal, Inc., 17 FERC ¶ 61,231 at 61,445 (1981).

The Public Staff asserted that electricity must be delivered to an electric power supplier in order to be eligible for RECs. The Commission disagrees. G.S. 62-133.8(b)(2)(e) allows electric power suppliers to comply with REPS by, among other things, purchasing renewable energy certificates "derived from" renewable energy facilities. The Commission has approved renewable energy facility registrations for numerous small solar facilities whose owners use the power directly rather than selling it to an electric power supplier. In addition, Commission Rule R8-67(g)(3) addresses large renewable energy facilities that are interconnected on the customer's side of the utility meter. There is no requirement that a renewable energy facility's output be sold or delivered to an electric power supplier in order to be eligible for the issuance of RECs. However, as discussed above, the electric use must be net of station service in order to be eligible for the issuance of RECs.

As regards the issue of whether WEP's facility meets the statutory definition of a combined heat and power facility that is eligible to earn RECs, the Commission agrees with the Public Staff that this is not the case. G.S. 62-133.8(a)(7)(b) requires that a combined heat and power facility must generate "useful, measureable combined heat and power derived from a renewable energy resource" in order to be eligible for REC issuance pursuant to REPS. This a two-part standard: the facility must produce both electric and thermal energy, and both must be useful and measurable. Although WEP's facility uses a renewable resource, it does not meet the two-part definition set out in G.S. 62-133.8(a)(7)(b) because it consumes all of the electricity that it generates. Based on the record, the Commission finds that none of the facility's energy output is eligible for REC issuance. Therefore, the Commission concludes that it is necessary to pursue revocation of the facility's registration as a new renewable energy facility.

Based upon the foregoing and the entire record in this proceeding, the Commission hereby: (1) denies WEP's request for a declaratory ruling that the useful thermal energy generated at its biomass-fueled facility remains eligible to earn RECs and (2) notices the Commission's intent to revoke the registration of WEP's biomass-fueled facility as a new renewable energy facility effective August 24, 2012.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of August, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Bh081012.01

DOCKET NO. P-1262, SUB 5

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition for Arbitration of Time Warner Cable	)	
Information Services (North Carolina), LLC, of	)	RECOMMENDED
An Interconnection Agreement with Pineville	)	ARBITRATION
Telephone Company Pursuant to Section 252(b)	)	ORDER
of the Communications Act of 1934, as Amended	)	

BEFORE: Commissioner William T. Culpepper, III, Presiding, Commissioner Bryan E. Beatty, and Commissioner ToNola D. Brown-Bland

APPEARANCES:

FOR TIME WARNER CABLE INFORMATION SERVICES (NORTH CAROLINA), LLC:

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FOR THE TOWN OF PINEVILLE d/b/a PINEVILLE TELEPHONE COMPANY:

Daniel C. Higgins
Burns, Day & Presnell, P.A.
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Raleigh, North Carolina 27605

FOR THE USING AND CONSUMING PUBLIC:

Robert S. Gillam
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BY THE COMMISSION: On October 26, 2011, Time Warner Cable Information Services (North Carolina), LLC (TWCIS (NC)) filed a Petition for Arbitration of an Interconnection Agreement (ICA) with Pineville Telephone Company (Pineville) pursuant to Section 252(b) of the Communications Act of 1934, as amended (the Act). TWCIS (NC) stated that it is a certificated competing local provider (CLP) of telecommunications services in North Carolina; that Pineville is an incumbent local exchange company (ILEC) and also a rural local exchange company (RLEC) as defined in the Act; that under Section 251(a) of the Act, Pineville is obligated to interconnect with the facilities of TWCIS (NC); and that under Section 251(b) of the Act, Pineville is required to enter into number portability and reciprocal compensation arrangements with TWCIS (NC). TWCIS (NC) also asserted that it had sent Pineville a bona fide request to negotiate an ICA, as well as a draft ICA, but Pineville had provided essentially no response.

The Commission issued an Order on October 31, 2011, in which it relieved TWCIS (NC) of the obligation to prefile testimony with its arbitration petition, relieved Pineville of its obligation to prefile testimony with its response, and established a deadline for Pineville's response.

On November 21, 2011, Pineville filed its Response to Petition for Arbitration. In its Response, Pineville asserted that as a RLEC under Section 251(f)(1) of the Act, it was exempt from any obligation to negotiate an ICA under Section 251(c); that its rural exemption had not been terminated; and that shortly after the filing of TWCIS (NC)'s Petition, it had provided TWCIS (NC) with a markup of TWCIS (NC)'s proposed ICA.

On December 5, 2011, the Commission issued an Order Scheduling Arbitration Hearing. In its Order, the Commission held that under the Declaratory Ruling issued by the Federal Communications Commission (FCC) on May 26, 2011[1], Pineville was required, notwithstanding its status as a RLEC, to interconnect with TWCIS (NC) and provide TWCIS (NC) with arrangements for number portability and reciprocal compensation. The Commission directed TWCIS (NC) and Pineville to file a joint issues matrix; established deadlines for the filing of direct and rebuttal testimony; and set the case for hearing on March 20, 2012.

TWCIS (NC) and Pineville filed a joint issues matrix on January 19, 2012. On February 17, 2012, TWCIS (NC) filed the direct testimony of Julie P. Laine, Group Vice President, Regulatory of Time Warner Cable Inc., the parent company of TWCIS (NC), and Pineville filed the direct testimony of Joel O. Williams, President of Mid-South Consulting Engineers, Inc. On March 2, 2012, TWCIS (NC) filed the rebuttal testimony of witness Laine and Pineville filed the rebuttal testimony of witness Williams.

On March 8, 2012, Pineville and TWCIS (NC) filed a joint motion requesting that the Commission cancel the previously scheduled hearing, direct the parties to file briefs and/or proposed orders, and decide the case on the basis of the written record. The parties noted in the joint motion that they had identified only six issues to be resolved in this proceeding. The parties further noted that two issues on the parties' joint issues matrix filed on January 19, 2012 had since been resolved, leaving only four issues for resolution by the Commission. The parties asserted that the remaining four unresolved issues were straightforward and, as supplemented by briefing, could be decided on the basis of the pleadings and testimony filed in this docket. On March 13, 2012, the Commission granted the parties' motion, canceled the hearing, and directed the parties and the Public Staff to file briefs and/or proposed orders by April 13, 2012.

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[1] *In the Matter of Petition of CRC Communications of Maine, Inc. and Time Warner Cable, Inc. for Preemption Pursuant to Section 253 of the Communications Act, as amended*, Declaratory Ruling, 26 FCC Rcd 8259, FCC 11-83 (2011).

On April 13, 2012, TWCIS (NC) filed its brief, Pineville filed its proposed order and brief, and the Public Staff filed its proposed order in this docket.

Based on the foregoing, the evidence and exhibits filed by the parties, and the entire record in this proceeding, the Commission now makes the following

FINDINGS OF FACT

1. TWCIS (NC) is required to submit Access Service Requests (ASRs) and Local Service Order Requests (LSRs) to Pineville by facsimile rather than email.

2. The ICA should not include language committing TWCIS (NC) or its parent corporation to contribute to a North Carolina universal service fund in the event that one is established in the future.

3. There is insufficient evidence in the record to enable the Commission to require the inclusion of a provision in the ICA providing for the payment by TWCIS (NC) of premium labor rates as reflected in Attachment 1 to the ICA proposed by Pineville.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

MATRIX ISSUE NO. 1: Should TWCIS (NC) be required to submit ASRs to Pineville by facsimile rather than by email?

MATRIX ISSUE NO. 4: Should TWCIS (NC) be required to submit LSRs to Pineville by facsimile rather than by email?

POSITIONS OF PARTIES

TWCIS (NC): No. Pineville is obligated under federal law to provide interconnection on “rates, terms, and conditions that are just, reasonable, and nondiscriminatory”. 47 U.S.C. 251(c)(2)(D). In today’s technological environment, email is a more common and accepted practice than facsimile transmission—which consumes paper, toner and, where a stand-alone machine is utilized, operator time—and it would be unreasonable to allow Pineville to insist on facsimile delivery of service orders when email delivery is available as a familiar, less costly, and more efficient alternative.

PINEVILLE: Yes. The language of Sections 15.4 and 19.7 of the proposed ICA should read as proposed by Pineville. These provisions of the proposed ICA concern the means by which TWCIS (NC) would submit ASRs and LSRs to Pineville. Pineville is a small operation and currently receives by facsimile transmission all ASRs directed to it by other carriers. This is the process which Pineville has in place for receiving service orders, and it does not have either an electronic ordering system or any email delivery system set up to receive service orders. Neither the Act nor any implementing FCC regulation requires Pineville to accommodate TWCIS (NC)’s request in this regard.

PUBLIC STAFF: No. Email is an accepted method of electronic communication, and TWCIS (NC) should be permitted to substitute email delivery to Pineville for facsimile transmission.

DISCUSSION

In Sections 15.4 and 19.7 of the ICA, the parties have agreed to utilize a "manual method" of transmittal of basic service orders—*i.e.*, LSRs and ASRs. TWCIS (NC)'s position is that email delivery of a properly executed PDF document to the corporate email account of a designated Pineville representative constitutes an acceptable method of "manual" ASR or LSR delivery. Pineville's position is that the parties may only use fax machines to transmit ASRs and LSRs.

As justification for its position, Pineville asserted that it is a small operation and currently receives by facsimile transmission all ASRs directed to it by other carriers. This is the process which Pineville has in place for receiving service orders, and it does not have either an electronic ordering system or any email delivery system set up to receive service orders. Further, Pineville asserted that neither the Act nor any implementing FCC regulation requires Pineville to accommodate TWCIS (NC)'s request in this regard. Pineville witness Williams testified that Pineville is familiar and comfortable with receiving ASRs by facsimile, and currently it receives all ASRs from other carriers by this method. In addition, witness Williams testified that Pineville has no electronic ordering system or email address set up to receive service orders by email, and it has no employee dedicated to monitoring such an address.

TWCIS (NC) contended that the Commission should not be persuaded by the argument made by Pineville and should instead issue an order directing the parties to revise Section 15.4 and Section 19.7 of the ICA to clarify that email delivery of a properly executed PDF document to the corporate email account of a designated Pineville representative constitutes an acceptable method of "manual" ASR or LSR delivery. TWCIS (NC) noted that Pineville's statement that it does not have either an electronic ordering system or any email delivery system set up to receive service orders is understandable given that Pineville has not yet entered into an ICA. When viewed in this context, TWCIS (NC) believes that such an assertion adds little to the discussion of whether Pineville should permit TWCIS (NC) to submit orders via an email delivery system.

In TWCIS (NC)'s view, it is more telling what Pineville does not assert. TWCIS (NC) observed that Pineville does not claim that it lacks the capability of receiving service orders transmitted via email—which, of course, would be a highly suspect assertion for any business today, particularly a telecommunications company purporting to "offer the most up-to-date products and services to all our customers, offering a full range of features and services including broadband." *See* http://pinevilledsl.net/ Nor does Pineville contend that utilizing email to exchange service orders would be burdensome or technically infeasible. To the contrary, email is a widely accepted method of electronic communication, which has largely replaced facsimile for communications among businesses. Indeed, according to TWCIS (NC), technology has blurred the lines between these technologies such as they are entirely substitutable—a fax can be originated as email, and an email can be originated as a fax.

In TWCIS (NC)'s opinion, Pineville is obligated under federal law to provide interconnection on "rates, terms, and conditions that are just, reasonable, and nondiscriminatory". 47 U.S.C. 251(c)(2)(D). TWCIS (NC) asserted that in today's technological environment, email is a more common and accepted practice than facsimile transmission—which consumes paper, toner and, where a stand-alone machine is utilized, operator time—and it would be unreasonable to allow Pineville to insist on facsimile delivery of service orders when email delivery is available as a familiar, less costly, and more efficient alternative. Pineville, for its own reasons, apparently prefers or finds it more convenient to utilize fax machines to transmit service orders. TWCIS (NC) contended, however, that an ILEC's mere preference or convenience does not dictate its obligations under federal law.

Moreover, TWCIS (NC) noted that email delivery is commonly accepted as a "manual" method for exchanging service orders and has been approved previously by this Commission in other ICAs. *See, e.g.,* Interconnection Agreement Between Windstream North Carolina, LLC, Windstream Concord Telephone, and AT&T Communications of the Southern States, LLC, Docket Nos. P-118, Sub 169, P- 16, Sub 239 (filed August 21, 2009), at 65 (Attachment B: Price List) (defining "Manual" process to include orders sent via facsimile, electronic mail or U.S. Postal Service); Interconnection Agreement Between Windstream Lexcom Communications, Inc. and Piedmont Communications Services, Inc., Docket No. P-31, Sub 151 (filed March 2, 2011) (same).

In its Proposed Order, the Public Staff agreed with TWCIS (NC). The Public Staff stated that, as TWCIS (NC) witness Laine pointed out in her rebuttal testimony, Pineville does not contend that it lacks email capability, or that the use of email to receive ASRs and LSRs would be burdensome or technically infeasible. The Public Staff noted that the practice of sending business communications by email is widely accepted, and Pineville should not be allowed to insist on a less common and more costly method simply for its own convenience.

The issue before the Commission is whether TWCIS (NC) can force Pineville to accept ASR and LSR orders by email instead of facsimile, the order exchange mechanism that Pineville currently has in place and prefers. The Commission's decision on this issue will be determined based on the law as established in the Act and the particular facts presented in this proceeding.

The Act establishes the duties of telecommunications carriers to interconnect in two specific sections of the statute. In Section 251(a), the Act states that each telecommunications carrier has a general duty (1) to interconnect directly and indirectly with the facilities and equipment of other telecommunications carriers. This section is broadly applicable to all telecommunications carriers. In Section 251(c), the Act, in pertinent part, states:

> (2) <u>INTERCONNECTION</u>. The duty to provide, for the facilities and equipment of any requesting telecommunications carrier, interconnection with the local exchange carrier's network---

> (A) for the transmission and routing of telephone exchange service and exchange access;
>
> (B) at any technically feasible point within the carrier's network;
>
> (C) that is at least equal in quality to that provided by the local exchange carrier to itself or to any subsidiary, affiliate, or any other party to which the carrier provides interconnection; and
>
> (D) on rates, terms, and conditions that are just, reasonable, and nondiscriminatory, in accordance with the terms and conditions of the agreement and the requirements of this section and section 252.

The specific duties articulated in Section 251(c) are only imposed on ILECs and are not applicable to carriers in general.

In this case, TWCIS (NC) seeks to interconnect with Pineville based solely upon its right to do so under the general duties imposed on all carriers specified in Section 251(a).[1] TWCIS (NC)'s decision to pursue interconnection pursuant to Section 251(a) rather than Section 251(c) has advantages and disadvantages. On the one hand, the decision allows TWCIS (NC) to avoid the uncertainty, time, expense and effort that the requesting carrier/competitor would be required to expend proving to a state commission that its interconnection request is technically feasible, that the RLEC will not be unduly burdened economically by the interconnection request and that the interconnection request is consistent with the universal service principles and should therefore be permitted. 47 U.S.C. 251(f)(1)(B). This is a considerable advantage to a requesting carrier/competitor in today's telecommunications market.

This advantage, however, is offset by the limited interconnection options available to a competitor making this choice. That is, by making this choice, a requesting carrier/competitor forfeits its ability to insist that the ILEC provide the <u>additional</u> interconnection arrangements mandated by Section 251(c) to it upon its request. For instance, under the language of Section 251(c) and the FCC's interpretation of the requirements of that section[2], an ILEC must

[1] In its Pleadings and Post Hearing Brief, TWCIS (NC) asserted that it "[seeks] to exercise its statutory rights to seek interconnection pursuant to Section 251(a) of the Act." TWCIS (NC) Post Hearing Brief p. 2. TWCIS (NC) makes equally clear that it "has not sought to exercise [interconnection] rights under Section 251(c)." Paragraph 14, Petition for Arbitration.

[2] In the First Report and Order, the FCC makes clear that an ILEC bears an additional obligation of providing interconnection between its network and that of a requesting carrier at a level of quality that is at least indistinguishable from that which the incumbent provides itself, a subsidiary, an affiliate or any other party when the carrier makes a request for interconnection pursuant to Section 251(c). First Report and Order, 11 FCC 15499, ¶ 224 (1996). "This is the <u>minimum</u> requirement." (Emphasis added.) First Report and Order, ¶ 225. The FCC also makes clear that Section 251(c) requires an ILEC to provide a requesting carrier with superior interconnection arrangements than the ILEC currently provides itself or its affiliates: (1) if such arrangements are technically feasible; and, (2) if the carrier "compensate[s the] incumbent LECs for the economic cost of the higher quality interconnection." First Report and Order, ¶ 225. Again, this is an additional obligation imposed only on ILECs by Section 251(c).

provide superior interconnection arrangements upon request if technically feasible and if the requesting party is willing to compensate the ILEC for the additional costs caused by the arrangement. Thus, in the case at hand, if TWCIS (NC) had requested the ability to submit orders via a more modern and efficient email order submission process pursuant to Section 251(c), Pineville would be compelled to accommodate TWCIS (NC)'s request.[1]

By contrast, neither the language of Section 251(a) nor the FCC's interpretation of the obligations linked to Section 251(a) expressly require Pineville to provide TWCIS (NC) with superior interconnection arrangements upon request. In fact, in its most recent pronouncement, the FCC makes clear that a requesting carrier seeking interconnection arrangements pursuant to Section 251(a) is entitled to much less than the superior, additional interconnection arrangements that would be available to a carrier making a request pursuant to Section 251(c). See *In the Matter of Petition of CRC Communications of Maine, Inc. and Time Warner Cable Inc. for Preemption Pursuant to Section 253 of the Communications Act, as Amended*, Declaratory Ruling, 26 FCC Rcd 8259, FCC 11-83 (2011) (*Declaratory Ruling*). In that decision, the FCC determined that a state commission is authorized to arbitrate disputes arising when an interconnection request is made pursuant to Section 251(a) rather than Section 251(c). In doing so, the FCC clearly recognized that a rural ILEC is not obligated to provide anything more than basic, interconnection arrangements to a requesting carrier when its rural exemption remains intact. The FCC stated: "Our interpretation also provides competing carriers with a clear path for seeking implementation of a rural LEC's local competition obligations under sections 251(a) and (b), including basic interconnection … even when the rural LEC is exempt from the more rigorous obligations of section 251(c)." *Declaratory Ruling* ¶ 23. Emphasis added.

In this case, Pineville's rural exemption remains intact. Thus, under the Act, and the FCC's most recent pronouncement interpreting the Act, Pineville, as an RLEC, is only obligated to provide TWCIS (NC) with basic interconnection arrangements. Pineville has offered to provide TWCIS (NC) with the basic ability to interconnect with its system through the use of its facsimile order exchange system. Pineville's position in this regard may not be overruled by the Commission unless TWCIS (NC) proves, by the greater weight of the evidence, that the basic interconnection arrangements being offered are "unjust or unreasonable." [2] G.S. 62-75

The evidence in this proceeding indicates that Pineville is a small operation. As of December 31, 2011, Pineville served less than 1,500 residential and business lines, with 10 full time employees and 6 employees shared with other Town functions. Pineville currently receives by facsimile transmission all ASRs directed to it by other carriers. This is the process which Pineville has in place for receiving service orders, and it does not have either an electronic ordering system or any email delivery system set up to receive service orders. Pineville is familiar and comfortable with receiving service orders by facsimile. Moreover, while there is abundant evidence in this record that email is a more common and efficient method of delivering

[1] This scenario, of course, assumes that Pineville's rural exemption had been terminated, that the request was technically feasible and that TWCIS (NC) had indicated a willingness to pay any additional costs that Pineville would incur to provide such arrangement.

[2] 47 U.S.C. 201(b) provides: "All charges, practices, classifications, and regulations for and in connection with such communication service, shall be just and reasonable, and any such charge, practice, classification, or regulation that is unjust or unreasonable is hereby declared to be unlawful[.]"

the orders in question, there is nothing in the record in this case to suggest that the use of the facsimile would not ultimately accomplish the task of order delivery. In fact, as TWCIS (NC) has pointed out in its brief, the Commission has recently approved ICAs that permit the submission of manual orders by facsimile. *See, e.g.,* Interconnection Agreement Between Windstream North Carolina, LLC, Windstream Concord Telephone, and AT&T Communications of the Southern States, LLC, Docket Nos. P-118, Sub 169, P-16, Sub 239 (filed August 21, 2009), at 65 (Attachment B: Price List) (defining "Manual" process to include orders sent via *facsimile,* electronic mail or U.S. Postal Service); Interconnection Agreement Between Windstream Lexcom Communications, Inc. and Piedmont Communications Services, Inc., Docket No. P-31, Sub 151 (filed March 2, 2011) (same). Presumably, this Commission would not have approved this method had it deemed such method unreasonable. Finally, there is no indication in this record that TWCIS (NC) is willing to bear <u>any</u> financial responsibility for the additional costs that the use of such an ordering system might impose on Pineville.

Based on these facts, the Commission cannot find, by the greater weight of the evidence, that Pineville's insistence that service orders only be delivered by facsimile is either unjust or unreasonable.

CONCLUSION

The Commission concludes that TWCIS (NC) is required to submit ASRs and LSRs to Pineville by facsimile rather than email.

<u>EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2</u>

<u>MATRIX ISSUE NO. 5</u>: Should the ICA include provisions on the obligation of TWCIS (NC) or its parent corporation to contribute to a North Carolina universal service fund?

POSITIONS OF PARTIES

TWCIS (NC): Pineville seeks the inclusion of language relating to TWCIS (NC)'s obligation to contribute to a universal service fund should one be established by the Commission. Pineville also seeks the inclusion of language requiring that "all contributions to such funds" are paid by TWCIS (NC)'s wholesale customers. Such language is inconsistent with Sections 251 and 252 of the Act and, therefore, must be rejected. In addition, the proposed language purports to address issues which are outside of the scope of the interconnection relationship and, therefore, are not appropriate to include in an ICA. Moreover, the proposed language purports to impose requirements on third party, unregulated wholesale customers which extend beyond any applicable regulatory authority of the Commission.

PINEVILLE: Pineville proposes that the ICA include the following language in Section 29.1:

> TWCIS (NC) agrees to participate, in accordance with the Commission's rules and special Order, and to contribute to any fund or plan established by the Commission or the FCC to help provide support for the universal service in North Carolina, should one or more such funds be established. In this regard, TWCIS (NC) shall also insure that all contributions to such funds are paid by any third-party customer (last mile provider) of TWCIS (NC) to which TWCIS (NC) provides what it contends are wholesale services in the Pineville exchange.

Any ICA between the parties should affirmatively provide for support by TWCIS (NC) of any fund established by the Commission or the FCC to preserve and advance universal service in North Carolina, should such a fund be established in the future.

The Commission has the authority to not only require TWCIS (NC), but its corporate affiliate, Time Warner Cable, which is an interconnected Voice over Internet Protocol (VoIP) service provider, to contribute to such a fund, should a fund be established, and that TWCIS (NC) should ensure that such contributions are made by Time Warner Cable.

PUBLIC STAFF: The language proposed by Pineville deals with telecommunications regulatory policy, not with the parties' interconnection or their business relationship. Moreover, it would impose requirements on TWCIS (NC) that can only be satisfied by the action of TWCIS (NC)'s parent corporation, Time Warner Cable. Such a provision is not appropriate for inclusion in an ICA.

DISCUSSION

TWCIS (NC) witness Laine stated in direct testimony that Pineville's proposed language is so vague that the full implications of the language are not readily apparent. Witness Laine maintained that, for example, the language requires TWCIS (NC) to "participate" in any fund or plan established by the Commission or the FCC regarding universal service. Witness Laine stated that she is concerned that the proposed language could be read to require TWCIS (NC) to seek Eligible Telecommunications Carrier (ETC) status in North Carolina, a decision which hinges on many considerations unrelated to achieving interconnection with Pineville.

Witness Laine stated that, in addition, the language as drafted could be interpreted to require that TWCIS (NC) contribute to any universal service plan or fund established by the FCC or the Commission without regard to whether the rules of such plan or fund would require such contributions by TWCIS (NC). Witness Laine maintained that the language requires TWCIS (NC) to "ensure" that any contributions to such funds are "paid" by its wholesale customers. Witness Laine asserted that TWCIS (NC) interprets this language as attempting to impose a substantive funding requirement on TWCIS (NC)'s customers irrespective of whether applicable state or federal law includes any such requirement. Witness Laine argued that, in this regard, Pineville's proposed language seems nothing more than a blatant attempt to use this regulatory process to achieve an unfair competitive advantage vis-à-vis TWC Digital Phone by driving up the costs to its customers.

Witness Laine argued that, moreover, it is not clear how the Commission or Pineville could require TWCIS (NC) and its customers to participate in any federal or state programs as a condition of obtaining interconnection, a federal right granted to TWCIS (NC) – without any such condition – pursuant to Section 251 of the Act. Witness Laine asserted that imposing such a condition on TWCIS (NC) in an arbitration proceeding, as opposed to a proceeding of general applicability in which all parties similarly situated to TWCIS (NC) would be treated the same and have the same obligations, appears to violate Section 253, which prohibits states from imposing "legal requirement[s]" on competitive telecommunications carriers that would act as a barrier (or barriers) to entry, unless such requirements are imposed on a "competitively neutral basis and [are] consistent with section 254." (Sections 253(a) and (b))

Witness Laine further stated that Pineville's proposed language is unique. Witness Laine testified that she cannot recall ever being asked to include language as proposed by Pineville in an ICA.

Witness Laine argued that there are numerous reasons why the language should not be included. Witness Laine stated that, in the broadest sense, Pineville's proposal is an attempt to inject an issue of general applicability regarding universal service funding into an agreement between two parties. Witness Laine asserted that ICAs are not the appropriate vehicle for debating policy issues that apply generally to all similarly situated entities. Witness Laine maintained that the issue addressed by Pineville's proposed language has nothing to do whatsoever with the matters in issue – namely, TWCIS (NC)'s request to interconnect with Pineville.

Witness Laine noted that TWCIS (NC) was required to certify as a condition of its certification as a CLP in North Carolina that it would "participate to the extent it may be required to do so by the Commission in the support of universally available telephone services at affordable rates." (Commission Rule R17-2(a)(4)) Witness Laine stated that, similarly, Commission Rule R17-3(b) states that "[a]ny CLP offering telecommunications services in North Carolina will be required to participate in such [universal service] fund." Witness Laine asserted that if Pineville is seeking to impose obligations on TWCIS (NC) and its wholesale customers that go beyond the requirements of North Carolina's rules, it should initiate a proceeding to amend those rules rather than seek to require TWCIS (NC) and its customers adopt Pineville's views on universal service as a condition of interconnection – a federal statutory right granted to TWCIS (NC) by Congress and a federal statutory obligation with which Pineville is required to comply.

Witness Laine maintained that under Section 252 of the Act, the Commission is charged with resolving disputed issues in arbitration consistent with the requirements of Section 251. Witness Laine stated that since the language proposed by Pineville is outside the scope of Section 251 and, in fact, would conflict with Section 253, there is no legal basis for considering the language proposed by Pineville and, as a result, Pineville's proposed language should be rejected.

Pineville witness Williams stated in direct testimony that Pineville believes that any ICA between the parties should affirmatively provide for support by TWCIS (NC) of any fund or plan established by the Commission or the FCC to help provide support for universal service in North Carolina, should any such fund be established. Witness Williams maintained that inclusion of such a provision in the ICA would be fully consistent with the commitment TWCIS (NC) made in its application to the Commission for authority to offer services as a CLP. In addition, witness Williams asserted that the only service TWCIS (NC) intends to provide is what it characterizes as wholesale telecommunications service. Witness Williams noted that the only customer TWCIS (NC) intends to serve is its corporate affiliate, Time Warner Cable, an entity not certificated by the Commission and not subject to the Commission's jurisdiction. Witness Williams maintained that this arrangement is intended to facilitate Time Warner Cable's offering of its "Digital Phone" service in the Pineville exchange. Witness Williams stated that under these circumstances, TWCIS (NC) should also explicitly commit to ensuring that any such contributions to such funds are paid by Time Warner Cable, as directed by the FCC. Witness Williams maintained that the FCC's Connect America Fund (CAF) Order has introduced significant uncertainty for small ILECs as to the impact of a changing federal approach to universal service support. Witness Williams asserted that this provision in the ICA is a reasonable and appropriate means of ensuring that support for universal service in North Carolina is provided, as directed by the Commission and/or the FCC.

Witness Laine argued in rebuttal testimony that Pineville has not provided support for its request to add language regarding TWCIS (NC)'s and its customers' obligation to pay into a yet-to-be-established universal service fund. Witness Laine maintained that witness Williams' explanation for requiring the inclusion of the language undercuts any justification for the language in the first place as any such funding mechanism will in fact be "directed by the Commission and/or the FCC" without the need of the additional filter of this ICA which risks inconsistencies with rules that may be adopted on a generic basis. Witness Laine asserted that Pineville's attempt to bind TWCIS (NC)'s customers to paying into a yet-to-be-established fund may well conflict with any such fund or result in the double payment of universal service contributions. Witness Laine maintained that Pineville's efforts to bind TWCIS (NC)'s customer "Time Warner Cable" – an entity over which Pineville concedes the Commission does not have jurisdiction – with respect to hypothetical future obligations is inconsistent with existing federal rules applicable to wholesale providers of telecommunications services.

Witness Laine further asserted that Pineville makes no attempt to tether its request to any requirement under federal law. Witness Laine stated that the interconnection sought by TWCIS (NC) is a right granted under federal law pursuant to Section 251 of the Act without any condition such as proposed by Pineville. Witness Laine maintained that, if adopted by the Commission, Pineville's language would appear to violate Section 253 of the Act, which prohibits states from imposing "legal requirement[s]" on competitive telecommunications carriers that would act as a barrier (or barriers) to entry, unless such requirements are imposed on a "competitively neutral basis and [are] consistent with section 254." Witness Laine argued that here the attempt to impose a requirement on TWCIS (NC) that is inconsistent with Section 254 is exactly the sort of barrier contemplated by Section 253.

TWCIS (NC) did not provide any additional comments on this issue in its brief other than what had been outlined in the direct and rebuttal testimony of TWCIS (NC) witness Laine.

Witness Williams stated in rebuttal testimony that TWCIS (NC) witness Laine first criticizes Pineville's use of the word "participate" in its proposed Section 29.1. Witness Williams asserted that this is the same term found in the Application for Certification as a CLP which TWCIS (NC) submitted to the Commission, which tracks the language of Commission Rule R17-2(a)(4). Witness Williams stated that, likewise, the same word ("participate") is found in Commission Rule R17-3(b).

Witness Williams argued that the language proposed by Pineville was intended to be consistent with the requirement set forth in Commission Rule R17-2(a)(4), which is an affirmative obligation on the part of TWCIS (NC) to "participate to the extent it may be required to do so by the Commission in the support of universally available telephone services at affordable rates." Witness Williams stated that the Commission's Rules provide that when the Commission establishes a State Universal Service Fund, any CLP offering telecommunications services in North Carolina will be required to participate in such a fund. Witness Williams noted that TWCIS (NC)'s reluctance to acknowledge its obligations in this regard in the proposed ICA is troubling.

Witness Williams stated that, further, although he is not a lawyer, it is his understanding that the FCC has ruled that states may extend universal service contribution requirements to intrastate revenues of both interconnected and nomadic VoIP service providers, so long as a state's particular requirements do not conflict with federal law or policies. Witness Williams further testified that in *In the Matter of Universal Service Contribution Methodology – Petition of Nebraska PSC and Kansas Corporation Commission for Declaratory Ruling that State USF May Assess Nomadic VoIP Intrastate Revenues*, WC Docket No. 06-122, FCC 10-185 (November 5, 2010), the FCC ruled that states could require state universal service fund contributions from nomadic VoIP providers. Witness Williams stated that the FCC had previously allowed states to require such contributions from interconnected VoIP providers such as Time Warner. Thus, witness Williams argued, the Commission could in the future require interconnected VoIP providers, such as TWCIS (NC)'s affiliate, Time Warner Cable, to contribute to a State Universal Service Fund if such a fund is established.

Witness Williams maintained that Pineville believes that any ICA between the parties should affirmatively provide for support by TWCIS (NC) of any Universal Service Fund or funding mechanism established by the Commission or the FCC to help provided support for universal service in North Carolina. Witness Williams noted that Time Warner Cable is not subject to direct regulation by the Commission, however, that TWCIS (NC) is. Witness Williams argued that inclusion of this provision in the proposed ICA is a reasonable and appropriate means of insuring that support for universal service in North Carolina is provided, as directed by the Commission and/or the FCC, by both TWCIS (NC) and Time Warner Cable, to the extent they are ordered to do so by the Commission and/or the FCC.

Pineville noted in its proposed order that the Commission recently recognized in its Order Ruling on Oral Argument issued in Docket No. P-100, Sub 167, that Section 254(f) of the Act vests States with the right to require providers of intrastate telecommunications services to contribute, on an equitable and nondiscriminatory basis, in a manner determined by the State to the preservation and advancement of universal service in that State. Pineville maintained that, as noted by the Commission in that Order, "the Commission derives ample authority to create and sustain universal service arrangements from both federal and state sources." Pineville asserted that there are a host of statutes that give the Commission both general and specific authority to promote universal service and regulate rates.

Pineville argued that the authority granted States under Section 254(f), which provides as follow, is quite broad:

> A State may adopt regulations not inconsistent with the Commission's rules to preserve and advance universal service. Every telecommunications carrier that provides intrastate telecommunications services shall contribute, on an equitable and nondiscriminatory basis, in a manner determined by the State to the preservation and advancement of universal service in that State. A State may adopt regulations to provide for additional definitions and standards to preserve and advance universal service within that State only to the extent that such regulations adopt additional specific, predictable, and sufficient mechanisms to support such definitions or standards that do not rely on or burden Federal universal service support mechanisms.

Pineville asserted that the "not inconsistent" language of Section 254(f) implicates other provisions of Section 254, such as Section 254(b)(4), which provides that "[a]ll providers of telecommunications services should make an equitable and nondiscriminatory contribution to the preservation and advancement of universal service."

The Public Staff stated in its proposed order that it agrees with TWCIS (NC) that Pineville's proposed language should not be incorporated into the parties' ICA. The Public Staff noted that first, as Pineville witness Williams acknowledged, the language adds nothing to the requirements of Rule R17-2(a)(4) and thus imposes no new obligations on TWCIS (NC). The Public Staff asserted that from the standpoint of TWCIS (NC) and Pineville, the provision is surplusage.

The Public Staff maintained that Pineville's proposed provision does impose new obligations on Time Warner Cable; but this is a reason to reject the provision, not a reason to approve it. The Public Staff noted that Time Warner Cable is not a party to the ICA between Pineville and TWCIS (NC). The Public Staff stated that a contractual agreement is binding on the parties who enter into it and affects their legal obligations; but it imposes no obligations on a third party, unless the third party's actions are controlled by one of the contracting parties. The Public Staff asserted that TWCIS (NC) does not control the actions of its parent corporation, Time Warner Cable. The Public Staff argued that Pineville's proposed language, which is designed to obligate Time Warner Cable to contribute to a North Carolina universal service fund, is therefore ineffective.

The Public Staff maintained that the language proposed by Pineville is outside the proper scope of an arbitration proceeding. The Public Staff asserted that under Section 252 of the Act, the issues in an arbitration proceeding must relate to the "interconnection, services, or network elements" provided by the parties to each other. The Public Staff noted that Section 252(a)(1) of the Act provides that "an incumbent local exchange carrier may negotiate and enter into a binding agreement" with a CLP "[u]pon receiving a request for interconnection, services, or network elements pursuant to section 251." The Public Staff stated that under Section 252(b)(1), "[d]uring the period from the 135th to the 160th day" after a request for negotiations is made, a party may petition for arbitration of any open issues. The Public Staff asserted that, thus, the issues to be addressed in an arbitration must relate to "interconnection, services, or network elements" provided under Section 251.

The Public Staff asserted that broad regulatory issues, such as the questions of how service to high-cost areas should be paid for or who should contribute to a universal service fund, should be addressed in a rulemaking proceeding where all interested parties can participate. The Public Staff maintained that, thus, it was inappropriate for Pineville to raise universal service issues in this arbitration, and its proposed language should not be adopted.

The Commission agrees with TWCIS (NC) and the Public Staff that Pineville's proposed Section 29.1 concerning contributions by TWCIS (NC) to any future universal service fund is not appropriate for inclusion in the ICA between the parties. As noted by both TWCIS (NC) and the Public Staff, the ICA at issue in this docket should address only interconnection issues between TWCIS (NC) and Pineville; the language proposed by Pineville is outside the scope of the interconnection relationship. As noted by TWCIS (NC) witness Laine, Pineville's request in this regard is unique and witness Laine stated that she could not recall ever having been asked to include such language in an ICA. Also, as extensively noted by Pineville, there are state and federal provisions in place that address universal service obligations and an ICA between carriers is not the appropriate place for language addressing any universal service fund obligations.

Therefore, the Commission concludes that it is not appropriate to adopt Section 29.1 as proposed by Pineville in the ICA between TWCIS (NC) and Pineville in this docket.

CONCLUSION

The Commission concludes that it is not appropriate to adopt Section 29.1 as proposed by Pineville for inclusion in the ICA between TWCIS (NC) and Pineville in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

MATRIX ISSUE NO. 6: Should the ICA provide for premium labor rates based on Pineville's costs?

POSITIONS OF PARTIES

TWCIS (NC): Pineville should identify or substantiate its proposed "premium labor rates" as reflected in Attachment 1 to the ICA proposed by Pineville.

PINEVILLE: TWCIS (NC) should pay Pineville if TWCIS (NC) requests (and Pineville provides) additional, expedited, or special services, beyond the processing of LSRs or ASRs during normal business hours. Pineville initially proposed to charge TWCIS (NC) for any such services requested by TWCIS (NC) on an hourly basis, based on Pineville's cost of providing the requested service. Pineville is willing to agree to include in Attachment 1 to the parties' ICA the labor rates which TWCIS (NC) negotiated with Lexcom Telephone in the ICA arbitrated in Docket No. P-1262, Sub 2.

PUBLIC STAFF: The record is not sufficiently clear to allow the Commission to decide whether a provision on premium labor rates should be included in the ICA.

DISCUSSION

TWCIS (NC) witness Laine stated in direct testimony that with regard to the "premium labor" charges that Pineville seeks to impose in the ICA, TWCIS (NC) believes that Pineville has an obligation to identify, specify, and support those charges. Witness Laine also asserted that Pineville must justify the charge by demonstrating that it is cost based, which it has failed to do. Witness Laine noted that Pineville stated that it seeks to charge an "hourly rate, based on ILEC's costs" for "premium labor" – but Pineville has yet to specify what that rate is, why the rate is appropriate based on its own costs, or even what constitutes "premium labor". Witness Laine argued that TWCIS (NC) should not be compelled to agree to charges which Pineville refuses to identify or substantiate. Witness Laine asserted that because Pineville cannot be permitted to impose an open-ended charge via the mechanism of an ICA, Pineville's "premium labor" proposal should be rejected.

Pineville witness Williams stated in his direct testimony that any ICA between the parties should establish that the party furnishing a service requested by the other party will be compensated for providing that service. Witness Williams stated that the labor rates would be based on Pineville's actual costs. Witness Williams maintained that to the extent certainty as to labor rates is deemed preferable, the labor rates set forth in the ICA between Lexcom and TWCIS (NC) could be used.

Witness Laine stated in rebuttal testimony that Pineville's proposal concerning premium labor rates is tantamount to a blank check which obligates TWCIS (NC) to pay for services which are not specified at rates which are not provided, much less agreed to. Witness Laine asserted that under Section 251 of the Act, Pineville has an obligation to identify, specify, and support any charges that it seeks to impose. Witness Laine argued that because Pineville has not justified its proposal and the rates are not specified, it must be rejected.

TWCIS (NC) did not provide any additional comments on this issue in its brief other than what had been outlined in the direct and rebuttal testimony of TWCIS (NC) witness Laine.

Witness Williams stated in rebuttal testimony that Pineville proposed that Attachment 1 to the proposed ICA reflect the fact that **if** TWCIS (NC) requests additional or special services from Pineville, other than the processing of LSRs, then Pineville will charge TWCIS (NC) for such service on an hourly basis based on Pineville's cost. Witness Williams maintained that these hourly charges would apply only if TWCIS (NC) requested additional special or expedited services from Pineville, beyond the processing of LSRs. Witness Williams noted that examples of such potential services that TWCIS (NC) might request would include things such as an after-hours request for cutovers or other special services or services requested on an expedited basis.

Witness Williams maintained that there would absolutely be a cost to Pineville for providing the requested services. Witness Williams stated that this reality is reflected in the labor rates provided for in the NECA Tariff for installation or repair services. Witness Williams noted that the labor rates set forth in NECA Tariff FCC No. 5 for installation or repair services are $47.57 per half hour per technician for overtime work and $63.42 per half hour per technician for premium time. Witness Williams stated that just like the order processing charge established in the NECA Tariff, the labor rates set forth in that Tariff are based on cost data collected by NECA from a sample of cost and average schedule companies.

Witness Williams asserted that in the ICA with Lexcom which was the subject of the arbitration in Docket No. P-1262, Sub 2, TWCIS (NC) voluntarily agreed to labor rates for expedited or special orders of $25.00 per half hour during normally scheduled working hours, $30.00 per half hour of overtime on a scheduled work day, and $50.00 per half hour for premium time on a day that is not a scheduled work day.

Witness Williams noted that Pineville has proposed that hourly rates for such special or expedited service orders be assessed based on Pineville's costs. Witness Williams stated that in an effort to resolve this issue, and to the extent certainty as to labor rates is deemed preferable, Pineville is willing to accept the labor rates established in the ICA between Lexcom and TWCIS (NC), even though Pineville is much smaller than Lexcom and thus witness Williams would expect its costs to be higher than Lexcom's costs.

Pineville noted in its proposed order that the inclusion of labor rates in Attachment 1 to an ICA was addressed by the Commission in *In the Matter of Petition of Sprint Communications Company L.P. for Arbitration of an Interconnection Agreement with Randolph Telephone Company Pursuant to Section 252(b) of the Telecommunications Act of 1996*, Docket No. P-294, Sub 30. Pineville stated that in that docket, the Commission ruled that Randolph Telephone's request to include services and associated rates in Attachment 1 to that agreement was appropriate, if cost support was provided to Sprint upon its request. Pineville maintained that there is no indication that TWCIS (NC) has made such a request here.

Pineville stated that it has proposed that hourly rates for such special or expedited service orders be assessed based on its actual costs. Pineville asserted that it alternatively proposes that the labor rates established in the ICA between Lexcom and TWCIS (NC) be used here. Pineville argued that given that Lexcom is many times larger than Pineville, there can be no legitimate concern that Pineville's labor costs are lower than Lexcom's were. Pineville maintained that the Public Staff could assist the parties in resolving this issue and if that is not possible, the Commission can resolve it for them.

The Public Staff stated in its proposed order that because witness Williams' proposal to accept the premium labor rates from the Lexcom ICA was made in his rebuttal testimony, TWCIS (NC) has not had an opportunity to respond to it, and some details of the proposal remain uncertain. The Public Staff asserted that it is not clear whether the $25.00 to $50.00 per half hour rates proposed by Pineville will apply to every ASR or DSR that Pineville performs, or only to certain unusually complex ASRs or DSRs where TWCIS (NC) specifically agrees that the rates will be in effect.

The Public Staff noted that it appears that Pineville is willing to accept the same charges and conditions accepted by TWCIS (NC) in its ICA with Lexcom. The Public Staff stated that, however, this is not clear from the prefiled direct and rebuttal testimony in this proceeding. The Public Staff maintained that the position of TWCIS (NC) with regard to Pineville's rebuttal testimony on this matter is unknown. The Public Staff maintained that this issue might have been clarified on cross-examination if there had been a hearing, but since the hearing in this case was canceled, the positions of the two parties on the issue remain unclear. The Public Staff stated that, consequently, the Commission is not in a position to resolve this issue, and the parties should negotiate further to find a resolution of the matter.

Witness Williams' proposal to accept the premium labor rates from the TWCIS (NC)/Lexcom ICA was made in his direct testimony (pages 9 and 10) and rebuttal testimony (page 9); therefore, TWCIS (NC) has had an opportunity to respond to it when it filed its rebuttal testimony and its brief. TWCIS (NC) has not addressed Pineville's proposal in this regard. Therefore, the Commission does not know whether it is acceptable to TWCIS (NC) to include the premium labor rates included in the TWCIS (NC)/Lexcom ICA in the parties' ICA. However, the Commission does agree with TWCIS (NC) that any charges imposed by Pineville should be specifically identified and not just "based on Pineville's cost".

The Commission agrees with the Public Staff that the Commission is simply not in a position to resolve this issue based on the filings made in this docket. Therefore, the Commission instructs the parties to negotiate this issue further.

CONCLUSION

The Commission instructs TWCIS (NC) and Pineville to negotiate further on this issue.

IT IS, THEREFORE, ORDERED as follows:

1. That TWCIS(NC) and Pineville shall prepare and file a Composite Agreement in conformity with the conclusions of this Order as outlined in the Commission's November 3, 2000, Order Modifying Composite Agreement Filing Requirements issued in Docket No. P-100, Sub 133. Such Composite Agreement shall be in the form specified in paragraph 4 of Appendix A in the Commission's August 19, 1996, Order in Docket Nos. P-140, Sub 50 and P-100, Sub 133, concerning arbitration procedure (Arbitration Procedure Order) as amended by the November 3, 2000 Order.

2. That, not later than Monday, July 2, 2012, any interested party to the arbitration may file objections to this Recommended Arbitration Order consistent with paragraph 3 of the Arbitration Procedure Order.

3. That, not later than Monday, July 2, 2012, any interested person not a party to this proceeding may file comments concerning this Order consistent with paragraphs 5 and 6, as applicable, of the Arbitration Procedure Order.

4. That, with respect to objections or comments filed pursuant to decretal paragraphs 2 or 3 above, the party or interested person shall provide with its objections or comments an executive summary of no greater than one and one-half pages, single-spaced or three pages, double-spaced containing a clear and concise statement of all material objections or comments. The Commission will not consider objections or comments of a party or person who has not submitted such an executive summary or whose executive summary is not in substantial compliance with the requirements above.

5. That parties or other interested persons submitting Composite Agreements, objections, or comments shall also file those Composite Agreements, objections, or comments, including the executive summary required in decretal paragraph 4 above, in electronic format in Microsoft Word.

ISSUED BY ORDER OF THE COMMISSION.
This the _1st_ day of June, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

bp060112.01

DOCKET NO. P-55, SUB 1841

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of BellSouth Telecommunications, Inc., d/b/a AT&T North Carolina v. Halo Wireless, Inc.	))))))	ORDER GRANTING RELIEF

BEFORE: Commissioner William T. Culpepper, III, Presiding; and Commissioner Bryan E. Beatty and Commissioner ToNola D. Brown-Bland

APPEARANCES:

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FOR THE USING AND CONSUMING PUBLIC

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BY THE COMMISSION: On March 29, 2010 and April 5, 2010, BellSouth Telecommunications, Inc., d/b/a AT&T North Carolina (AT&T or Complainant) and Halo Wireless, Inc. (Halo or Respondent) executed an MFN Agreement dated March 25, 2010 in which Halo adopted in its entirety the wireless Interconnection Agreement as executed between AT&T and T-Mobile USA, Inc ("the ICA"). On June 10, 2010, in Docket No. P-55, Sub 1809, the Commission approved the ICA.

On July 25, 2011, AT&T filed an unverified complaint against Halo alleging that Halo had breached the ICA by: (1) sending traffic to AT&T that is not "wireless originated traffic," as the ICA requires, but is instead, landline-originated intrastate intraLATA, intrastate InterLATA or interstate toll traffic for which switched access charges are due but have not been paid; (2) altering call detail information that is transmitted with the traffic that Halo sends to AT&T's network; and (3) failing to pay for certain facilities ordered by Halo pursuant to the ICA.

On July 27, 2011, the Commission issued an Order Serving Complaint (the Order) on Respondent. The Order directed the Respondent to satisfy the demands of the Complainant or to file an answer on or before August 11, 2011.

[1] The members of the NCTIA include the following Commission-regulated incumbent local exchange companies (ILECs): Barnardsville Telephone Company, Saluda Mountain Telephone Company, Service Telephone Company, Citizens Telephone Company d/b/a Comporium Communications, Ellerbe Telephone Company, North State Telephone Company d/b/a North State Communications, and the Town of Pineville d/b/a Pineville Telephone Company. Members of the NCTIA not regulated by the Commission include Atlantic Telephone Membership Corporation, Randolph Telephone Membership Corporation, Skyline Telephone Membership Corporation, and Wilkes Membership Corporation d/b/a Wilkes Telecommunications.

On August 11, 2011, both AT&T and Halo separately filed notification to the Commission that Halo had filed a Chapter 11 Bankruptcy Petition in the United States Bankruptcy Court, Eastern District of Texas. That filing operated as an automatic stay of proceedings against Halo until the Bankruptcy Court ruled otherwise.

The North Carolina Telecommunications Industry Association, Inc. (NCTIA) petitioned to intervene on August 12, 2011, and that petition was granted on August 18, 2011.

On August 19, 2011, the Commission issued an Order Holding Docket in Abeyance.

The Public Staff filed its notice of intervention on August 26, 2011.

On October 7, 2011, Halo formally notified the Commission that a Notice of Removal of the issues pending in this docket was filed in the United States Bankruptcy Court for the Eastern District of North Carolina and that, pursuant to federal law, jurisdiction to determine the matters in dispute in this docket was divested from the Commission and removed to the bankruptcy court.

On March 5, 2012, the United States Bankruptcy Court for the Eastern District of North Carolina issued an Order Allowing Motion to Remand (the Bankruptcy Order) certain state utility regulatory issues in dispute in this case back to the Commission for determination.

On May 1, 2012, the Commission issued an Order Reinstating Docket and Requiring Answer. The May 1, 2012 Order directed Respondent to satisfy the demands of the Complainant or to file an answer on or before May 21, 2012.

On May 21, 2012, Halo filed its Answer to AT&T's Complaint and denied that it breached the ICA.

Also on May 21, 2012, Halo filed the Motion of Halo Wireless Inc. to Dismiss Counts I, II, and III of AT&T's Complaint and Notice of May 16, 2006 Order Confirming Plan of Reorganization for Transcom Enhanced Services (Transcom).

On June 1, 2012, Complainant filed AT&T's Response and Memorandum in Opposition to Halo's Partial Motion to Dismiss (Response).

On June 5, 2012, Halo filed Halo Wireless, Inc.'s Reply in Support of Partial Motion to Dismiss (Reply).

On June 18, 2012, the Commission issued its Order Scheduling Hearing and Establishing Procedures (Scheduling Order) establishing the date for filing witness testimony and scheduling the hearing in this matter on August 7, 2012.

On June 27, 2012, the Commission issued an Order Denying Halo's Motion to Dismiss (Denial Order).

In accordance with the Scheduling Order, the parties pre-filed the direct and rebuttal testimony of AT&T witnesses Mark Neinast and J. Scott McPhee, the pre-filed direct testimony of Halo witnesses Russ Wiseman and Robert Johnson, and the pre-filed rebuttal testimony of AT&T witness Raymond W. Drause. Neither the Public Staff nor NCTIA filed direct testimony. NCTIA, however, did file the rebuttal testimony of NCTIA witness Linda N. Robinson.

On July 27, 2012, Counsel for AT&T filed a letter with the Commission advising the Commission that Halo had converted its pending bankruptcy proceeding to a Chapter 7 bankruptcy liquidation proceeding and that, as a result, Halo's affairs are now being overseen by Halo's Bankruptcy Trustee (Bankruptcy Trustee). Counsel advised the Commission that Halo's Bankruptcy Trustee had agreed to dispense with the August 7, 2012 evidentiary hearing and to have all currently pending matters in state commissions decided "on the papers".

On August 1, 2012, the Commission issued an Order Cancelling Hearing and Holding Docket in Abeyance. In a separate order, the Commission, with the permission and consent of the Bankruptcy Trustee, issued an order authorizing the immediate disconnect of all wholesale services that AT&T provided to Halo in North Carolina. See Order filed in Docket No. P-55, Sub 1874 on August 1, 2012.

On August 2, 2012, AT&T filed a Motion to Resolve the Case on Paper Record. In that motion and a subsequent letter filed by AT&T, the parties to this proceeding indicated that they consented to AT&T's Complaint being resolved "on the papers".

On August 6, 2012, the Commission issued an Order Permitting Proposed Orders to Be Filed by August 15, 2012. On August 15, 2012, AT&T, the Public Staff and NCTIA[1] jointly filed a proposed order in this docket. Halo did not submit such an order.

FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. Halo has materially breached the ICA by (a) sending landline-originated traffic to AT&T; (b) sending inaccurate call information to AT&T; and (c) failing to pay for facilities it has ordered pursuant to the ICA.

2. Without quantifying any specific amount due, Halo is liable to AT&T for access charges on the interstate and intrastate non-local landline traffic Halo has sent to AT&T for termination.

[1] In the Proposed Order filed jointly by AT&T, the Public Staff and NCTIA, NCTIA asks the Commission to hold that Halo is liable to its RLEC members for access charges for non-local landline traffic that Halo has sent to them for termination. The Commission notes that the individual RLECs (and the NCTIA) have not filed a complaint against Halo requesting such relief; that neither the RLECs nor NCTIA filed direct testimony in this proceeding alleging such injury; that NCTIA filed only rebuttal testimony and the Scheduling Order did not permit Halo to respond to the rebuttal testimony filed by the parties; and, that according to AT&T's Motion to Resolve Case on Paper Record and the subsequent follow up letter of AT&T, Halo consented to and the Commission was only asked to enter a decision on "the merits of AT&T's complaint" that Halo breached the AT&T/Halo ICA. For these reasons, the Commission declines to rule on the RLECs' request.

3. Without quantifying any specific amount due, Halo is liable to AT&T for the interconnection facilities charges that it has refused to pay to AT&T.

DISCUSSION AND ANALYSIS

In this proceeding, AT&T has alleged that Halo had breached the ICA by: (1) sending traffic to AT&T that is not "wireless originated traffic," as the ICA requires, but is instead, landline-originated intrastate intraLATA, intrastate InterLATA or interstate toll traffic for which switched access charges are due but have not been paid; (2) inserting incorrect Charge Number (CN) data in the call information it sends to AT&T; and, (3) failing to pay for certain interconnection facilities as required by the ICA.

In responsive pleadings and pre-filed testimony, Halo admits that it sent some traffic that began on a landline to AT&T for termination; that Halo populated the CN field with the number belonging to Transcom and not the party that originally initiated the call; and, that Halo ordered transport facilities from AT&T and now refuses to pay for those facilities.

Despite these admissions, Halo nevertheless contends that these actions do not constitute breaches of the ICA because the landline traffic first passed through its high volume end-user customer Transcom where it was terminated and a new wireless communication was forwarded to AT&T for termination. According to Halo, this wireless re-origination of a call that began as a landline call is permitted by and complies with the terms of the ICA. With regard to the other issues in AT&T's complaint, Halo contends that they too are permitted because the ICA requires the financially responsible party to be identified in the CN field and because the ICA does not require Halo to pay for transport facilities that are not required to comply with the terms of the ICA even if Halo admits to ordering those facilities. AT&T disputes these contentions. For the reasons stated below, the Commission finds no merit to Halo's contentions and concludes, based upon the record of this proceeding and the applicable law, that Halo has materially breached the ICA.

I. Halo Breached The ICA By Sending Traffic To AT&T That Is Not Wireless Originated Traffic.

On March 29, 2010 and April 5, 2010, AT&T and Halo entered into a wireless ICA which detailed their telecommunications services arrangement. In one pertinent part, the ICA states:

> Whereas, the Parties have agreed that ***this Agreement will apply only to*** (1) traffic that originates on AT&T's network or is transited through AT&T's network and is routed to Carrier's wireless network for wireless termination by Carrier; and (2) ***traffic that originates through wireless transmitting and receiving facilities before [Halo] delivers traffic to AT&T*** for termination by AT&T or for transit to another network. [Emphasis added].[1]

[1] Direct Testimony of AT&T witness J. Scott McPhee ("McPhee Direct"), Exhibit JSM-5.

On its face, this provision of the ICA and the ICA in general, allows Halo to only send traffic that originated on wireless equipment to AT&T.

This "wireless traffic only" provision is important because wireless traffic and landline traffic are regulated differently. Most notably, the geographic areas used to determine whether traffic is local (and therefore subject to reciprocal compensation charges) or non-local (and therefore subject to access charges, which are higher) differ greatly for wireless and landline traffic. Wireless traffic is classified as local or non-local based on Major Trading Areas (MTAs), which are quite large. For landline traffic, on the other hand, calls are classified as local or non-local based on "local calling areas," which are much smaller. There are only two MTAs in all of North Carolina, but 433 landline local calling areas.

AT&T's testimony in this proceeding indicated that all of the trunks that Halo ordered to deliver traffic to AT&T were trunks reserved for wireless traffic only.[1] As noted above, the ICA allowed Halo to only send traffic that originated on wireless equipment to AT&T for termination. Thus, it is understandable that AT&T billed Halo for termination as if all of Halo's traffic was wireless-originated, as the ICA required when the parties first began to exchange traffic. However, sometime shortly after AT&T began to receive traffic from Halo for termination, AT&T began to suspect that much of the traffic that Halo was sending it was originated on landline equipment, not wireless equipment. After confirming what it suspected, AT&T filed this complaint case.

The Commission has examined the testimony and the pleadings in this docket very carefully to determine factual contentions for which there are no disputes in deciding this case. In this proceeding, the evidence is undisputed that Halo sent traffic to AT&T that originated on landline networks. For example, Halo's President, Mr. Wiseman, acknowledged that "[m]ost of the calls probably did start on other networks before they came to Transcom for processing. It would not surprise me if some of them started on the PSTN [public switched telephone network]."[2]

In its pre-filed testimony AT&T indicated that it analyzed all the calls Halo sent to AT&T during one-week periods in June 2011 and September 2011, and during a four-week period in January-February 2012.[3] AT&T began its analysis by identifying the Calling Party Number (CPN) on each call received from Halo, *i.e.*, the telephone number of the person who started the call. AT&T then consulted the industry's Local Exchange Routing Guide (LERG) and the North American Number Portability (NANP) database to determine what kind of carrier (landline or wireless) owned that number and whether the carrier that owned the number had designated it in the LERG as landline or wireless.[4] Based on this, AT&T was able to determine how many landline-originated calls Halo was sending.[5] During the three periods reviewed, the

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[1] Direct Testimony of AT&T witness Mark Neinast ("Neinast Direct") at 9, lines 13-15.

[2] Testimony of Halo witness Russ Wiseman ("Wiseman Testimony") at 37, lines 17-19.

[3] AT&T witness Neinast Direct at 12, lines 18-20.

[4] *Id*. at 14, line 4-15, line 2.

[5] *Id*. at 15, lines 5-11.

call data showed that 76%, 73% and 60%, respectively, of the calls that Halo delivered to AT&T originated as landline calls.[1]

The call analysis/traffic study described in the testimony of AT&T witness Neinast showed the volume of landline-originated calls Halo was sending to AT&T and third-party carriers (such as the RLECs) for termination. As shown in Neinast Exhibit MN-4, during the three periods analyzed in 2011 and 2012, AT&T's analysis of call data showed that 76%, 69% and 63%, respectively, of the interexchange calls that Halo delivered to AT&T for routing to the RLECs or other third-party carriers for termination, originated as landline calls. AT&T's call analysis concerning Halo's traffic to a number of the RLEC members of the NCTIA showed that Halo was delivering to them significant amounts of both landline originated interexchange traffic and interMTA wireless traffic. *See* Neinast Exhibit MN-11.

Although the percentage of landline-originated calls was large and Halo admits to sending AT&T calls that started on landline networks, and that "[m]ost of the calls probably did start on other networks before they came to Transcom for processing", Halo nevertheless quibbles about the details of AT&T's call analysis. Halo contends that some calls that originated from what appear to be landline numbers could have, in some scenarios, actually originated from a wireless device. Based on this, Halo contends that CPNs are unreliable and cannot be used to identify the origination point or originating carrier on *any* of the calls Halo sends AT&T.[2]

The Commission disagrees with Halo. Although Halo had access to all of the same data AT&T used for its analysis, Halo presented no call analysis to support its claims, nor did it present any evidence of how much of the traffic it delivers originates on wireless devices with CPNs that the LERG "incorrectly" shows as landline. Furthermore, while there are some situations where CPN may not precisely identify the origination point or originating carrier of a call, those situations are the exception, not the rule. Simply put, the data and methods AT&T used are the same data and methods that the industry uses today for determining what AT&T sought to determine.

Admittedly, Halo's contentions are rebutted by AT&T witness Neinast's testimony. AT&T assumed for the sake of argument that 100% of calls from Level 3 and Bandwidth.com numbers were actually wireless-originated, and re-analyzed the call data based on that assumption. Even with this assumption, the data still showed that between 52% and 64% of the traffic that Halo sent to AT&T was landline-originated.[3]

The record establishes and the Commission finds that Halo has also delivered large volumes of landline originated interexchange traffic to AT&T (and subsequently to the RLECs) in violation of the parties' ICA. The Commission further finds that the AT&T traffic studies are competent and contain substantial evidence demonstrating that Halo delivered interexchange landline traffic to AT&T, of which significant amounts were interMTA wireless or interLATA landline traffic, all of which is subject to AT&T's access tariffs.

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[1] *Id*. at 15, lines 13-19; Exhibit MN-4.

[2] Halo witness Wiseman Testimony at 31 *et seq.*

[3] AT&T witness Neinast Direct at 18, line 21.

To summarize, Halo has offered no traffic studies of its own to contradict the studies showing that substantial amounts of Halo's traffic originated on landline facilities. Likewise, Halo has offered no traffic studies to contradict AT&T's traffic studies or the RLEC data showing that substantial amounts of Halo's traffic was interMTA non-local landline-originated interexchange traffic terminated to AT&T and RLEC end user customers. Based upon AT&T's call study data, the Commission concludes that Halo has been sending large amounts of landline-originated traffic to AT&T for termination either by it, or other third-party carriers, such as the RLECs.[1]

Halo's defense is its claim that all the calls it sent to AT&T, regardless of who dialed the number or on what carrier's network the call began, should be deemed to have originated with Transcom. The evidence in this proceeding is clear that no one at Transcom dialed these calls and neither the calling party nor the called party on any call was a Transcom customer. Nevertheless, Halo contends that whenever a call passed through Transcom, that call was terminated and Transcom then originated a new, local, wireless call before the call reached Halo. To understand this theory, we begin by explaining what Transcom is and the arrangement it had with Halo.

Both Halo and Transcom have equipment at the same tower site or sites that send traffic to North Carolina and the arrangement between them works as follows: Every call that comes to Halo first passes from the carrier whose end user customer originated the call to Transcom (typically, indirectly through intermediate carriers) at one of its four switching stations (in Dallas, New York, Atlanta, and Los Angeles). Transcom then sends the call to its equipment at the tower site, where Transcom transmits the call, wirelessly, for about 150 feet to Halo's equipment.[2] Halo then sends the call on to AT&T's tandem switch for termination to an AT&T end-user or to be passed on to a third-party carrier for termination.[3]

To envision how a call flowed through this arrangement, AT&T used the example of a call that begins with a girl picking up her landline phone in California and dialing her grandmother in Raleigh.[4] That landline call would travel across the country, eventually hit Transcom's equipment at a Halo/Transcom tower site, travel wirelessly to Halo for 150 feet and then be handed off to AT&T, which would terminate the call in Raleigh on its landline network and thus enable the girl and her grandmother to talk to each other. The call originated with the girl in California, who is the calling party, and is a non-local, landline-originated call, subject to access charges. According to Halo, however, when the girl's call reached Transcom's equipment at the tower site, Transcom terminated the call and then originated a new call to the grandmother that was both local and wireless, and, therefore, was only subject to reciprocal compensation charges. Halo makes this argument even though the calling party (the girl who started the call)

[1] The Commission need not determine the exact amount of landline originated traffic with precision in this proceeding since the Bankruptcy proceeding is required to determine the precise numbers as an element in calculating the damages that are due to AT&T as a result of Halo's breach of the ICA.

[2] Rebuttal Testimony of AT&T witness Raymond W. Drause ("Drause Rebuttal"), at 5, line 1– 8, line 3.

[3] *Id*. at 6, lines 20-22.

[4] *See* AT&T witness Neinast Direct at 21 and Ex. MN-7.

had no relationship with Transcom, did not dial Transcom's number, had no idea Transcom was even involved with the call, and ended up talking to the person she dialed in the first place (her grandmother) without dialing any extra numbers or codes.

The "logic" of Halo's "Transcom origination" theory runs as follows:

1. Transcom is an enhanced service provider (ESP) under federal law.

2. As an ESP, Transcom is treated like an end-user for purposes of access charges.

3. Therefore, Transcom must be treated as an end user for all purposes.

4. Since Transcom is treated as an end user, all calls must be deemed to terminate to Transcom and originate with Transcom.

5. Therefore, a call from California to Raleigh terminated with Transcom, which then originated a new, wireless call, which passed through Halo and then to AT&T in the same MTA as Transcom.

6. Thus, the call that AT&T received from Halo originated wirelessly, with Transcom, and Halo was not breaching its ICA.

Halo's theory that the call that AT&T receives from Halo originates wirelessly, with Transcom, and therefore that Halo does not breach the AT&T/Halo ICA fails for several reasons. First, and foremost however, the ESP/Transcom in the middle theory fails because the FCC rejected that theory in the Connect America Order.[1] In doing so, the Federal Communications Commission (FCC) singled out Halo by name, described Halo's arrangement of having traffic pass through a purported ESP[2] (*i.e.*, Transcom) before reaching Halo, noted Halo's theory that calls in this arrangement are "re-originated" in the middle by Transcom, and thereafter rejected that theory. The FCC stated the following in paragraphs 1003-06:

> 1003. In the *Local Competition First Report and Order*, the Commission stated that calls between a LEC and a CMRS provider that originate and terminate within the same Major Trading Area (MTA) at the time that the call is initiated are subject to reciprocal compensation obligations under section 251(b)(5), rather than interstate or intrastate access charges. As noted above, this rule, referred to as the "intraMTA rule," also governs the scope of traffic between LECs and CMRS

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[1] *Connect America Fund*, FCC 11-161, 2011 WL 5844975 (rel. Nov. 18, 2011) ("*Connect America Order*").

[2] In this proceeding, the parties devoted considerable time and energy trying to explain why Transcom should or should not be classified as an ESP. For the purpose of this decision, the Commission assumes without finding as a fact that Transcom is an ESP. In doing so, we note that Transcom's classification is unimportant to our analysis since the FCC decided in the Connect America Order that the ubiquitous presence of a wireless link in the middle of a wireline initiated call does not convert that call to a wireless call for the purposes that are at issue in this proceeding. The FCC's decision in this regards contains no exceptions. Thus, it matters not if Transcom is an ESP or not, a wireless link in the middle of a wireline initiated call simply will not convert that call to a wireless call for the purposes that are at issue in this proceeding.

> providers that is subject to compensation under section 20.11(b). The *USF/ICC Transformation NPRM* sought comment, *inter alia,* on the proper interpretation of this rule.
>
> 1004. The record presents several issues regarding the scope and interpretation of the intraMTA rule. Because the changes we adopt in this Order maintain, during the transition, distinctions in the compensation available under the reciprocal compensation regime and compensation owed under the access regime, parties must continue to rely on the intraMTA rule to define the scope of LEC-CMRS traffic that falls under the reciprocal compensation regime. We therefore take this opportunity to remove any ambiguity regarding the interpretation of the intraMTA rule.
>
> 1005. We first address a dispute regarding the interpretation of the intraMTA rule. Halo Wireless (Halo) asserts that it offers "Common Carrier wireless exchange services to ESP and enterprise customers" in which the customer "connects wirelessly to Halo base stations in each MTA." It further asserts that its "high volume" service is CMRS because "the customer connects to Halo's base station using wireless equipment which is capable of operation while in motion." Halo argues that, for purposes of applying the intraMTA rule, "[t]he origination point for Halo traffic is the base station to which Halo's customers connect wirelessly." On the other hand, ERTA claims that Halo's traffic is not from its own retail customers but is instead from a number of other LECs, CLECs, and CMRS providers. NTCA further submitted an analysis of call records for calls received by some of its member rural LECs from Halo indicating that most of the calls either did not originate on a CMRS line or were not intraMTA, and that even if CMRS might be used "in the middle," this does not affect the categorization of the call for intercarrier compensation purposes. These parties thus assert that by characterizing access traffic as intraMTA reciprocal compensation traffic, Halo is failing to pay the requisite compensation to terminating rural LECs for a very large amount of traffic. Responding to this dispute, CTIA asserts that "it is unclear whether the intraMTA rules would even apply in that case."
>
> 1006. We clarify that ***a call is considered to be originated by a CMRS provider for purposes of the intraMTA rule only if the calling party initiating the call has done so through a CMRS provider***. Where a provider is merely providing a transiting service, it is well established that a transiting carrier is not considered the originating carrier for purposes of the reciprocal compensation rules. Thus, we agree with NECA that ***the "re-origination" of a call over a wireless link in the middle of the call path does not convert a wireline-originated call into a CMRS-originated call for purposes of reciprocal compensation and we disagree with Halo's contrary position.*** [Emphasis added, footnotes omitted].

In reaching this conclusion, the FCC makes clear that an important element in its decision is that a call will only be considered to be originated by a wireless carrier if the calling party initiating the call has done so through a CMRS provider. In this case, Halo admits that there have been instances in which it has delivered calls to AT&T for termination that began as wireline calls and not wireless calls. In those instances, the FCC's analysis instructs that those calls are not wireless originated calls even if they subsequently are transited through wireless customer premises equipment (CPE) before being delivered to AT&T for termination. In this instance, the Commission concurs with the both the FCC's decision and the reasoning underlying the decision. In doing so, the Commission also notes that the Tennessee[1], South Carolina[2], Georgia[3], Wisconsin[4], and Missouri[5] Commissions reached similar decisions. This Commission views the analysis included in those Commission decisions as supportive of this decision.

Additionally, Halo's "ESP/Transcom in the middle" theory fails because there is no authority for Halo's contention that ESPs terminate every call they touch and then originate a new call.

Halo's theory rests on the idea that ESPs are deemed to be end-users, and therefore (according to Halo) Transcom must be deemed to have originated every call that passed through its equipment. To the contrary, the FCC has made clear that ESPs "are treated as end-users *for the purpose of applying access charges*"[6] only, and "are treated as end users *for purposes of our access charge rules*."[7] Thus, the "ESP exemption" is a legal fiction that allows ESPs to be treated like end users *for the purpose of not having to pay access charges*. That does not mean an ESP could use this limited "end-user" status to claim it "originates" calls that actually began when someone else picked up a phone and dialed a number. Moreover, the ESP exemption from access charges applies *only to the ESP itself*, not to any telecommunications carrier that serves

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[1] Order, *BellSouth Telecommunications LLC d/b/a AT&T Tennessee v. Halo Wireless, Inc.*, Docket No. 11-00119 (Tenn. Reg. Auth., Jan. 26, 2012) ("*Tennessee Halo Order*").

[2] Order Granting Relief against Halo Wireless, *Complaint and Petition for Relief of BellSouth Telecommunications LLC d/b/a AT&T Southeast d/b/a AT&T South Carolina v. Halo Wireless, Inc.*, Docket No. 2011-304-C (Pub. Serv. Comm. S. Car. July 17, 2012) ("*South Carolina Halo Order*").

[3] Order on Complaints, *Complaint of TDS Telecom on behalf of its Subsidiaries against Halo Wireless, Inc. Transcom Enhanced Services, Inc. and Other Affiliates for Failure to Pay Terminating Intrastate Access Charges for Traffic and for Expedited Declaratory Relief and Authority to Cease Termination of Traffic*, Docket No. 34219 (Ga. Pub. Serv. Comm'n July 17, 2012) ("*Georgia Halo Order*").

[4] Final Decision, *Investigation into Practices of Halo Wireless, Inc., and Transcom Enhanced Services, Inc.*, No. 9594-TI-100 (Pub. Serv. Comm'n of Wis., July 27, 2012) ("*Wisconsin Halo Order*").

[5] Report and Order, *Complaint of Halo Wireless, Inc. against Respondent Local Exchange Carriers*, File No. 2012-0331 (Mo. Pub. Serv. Comm'n August 13, 2012) ("Missouri *Halo Order*").

[6] *Implementation of the Local Competition Provisions in the Telecommunications Act of 1996, Intercarrier Compensation for ISP-Bound Traffic*, 16 FCC Rcd. 9151, ¶ 11 (2001) ("*ISP Remand Order*") (emphasis added, subsequent history omitted).

[7] *Northwestern Bell Tel. Co. Petition for Declaratory Ruling*, 2 FCC Rcd. 5986, ¶ 21 (1987) ("*Northwestern Bell Order*"). Five years after it was issued, this decision was vacated as moot. 7 FCC Rcd. 5644 (1992). The decision still carries weight, however, as the FCC's explanation of the ESP exemption.

the ESP, which means that any ESP exemption for Transcom would not apply to *Halo*.[1] [Emphasis added.]

Halo also tries to support its "Transcom origination" theory by citing *Bell Atlantic Tel. Cos. v. FCC*, 206 F.3d 1 (D.C. Cir. 2000), claiming that the court there "functionally" held that every ESP is an "origination" "endpoint" on every call. But that decision does not so hold, and in any event has no bearing here. The FCC was well aware of the D.C. Circuit's *Bell Atlantic* decision when it issued the *Connect America Order*, but still rejected Halo's theory that all calls originate with Transcom. *Connect America Order*, ¶¶ 1005-06. The court in *Bell Atlantic* also was not dealing with ESPs in general, but rather was dealing with Internet Service Providers (ISPs) in particular, so its discussion cannot be generalized to all purported ESPs. Transcom is not an ISP and Halo does not claim it is. Moreover, contrary to Halo's claim, the D.C. Circuit did not hold that ISPs are an origination "endpoint." Rather, it merely remanded to the FCC to consider that alternative as a possible way to look at what those providers do, and on remand the FCC took a different path, so it never had to address the issue.[2]

Finally, Halo's "ESP/Transcom in the middle theory" fails in this proceeding because there is no support for Halo's contention that an end-user such as Transcom, must originate every call that it touches.

Halo has argued that even if Transcom is not an ESP, it still must be deemed to have originated every call it touched. Halo claims that every entity must either be a common carrier or an end-user, that Transcom is not a common carrier and therefore must be an end-user, and therefore that Transcom originates every call it touches. Halo has failed to establish its premise, *i.e.*, that every entity involved in the world of communications must be either a common carrier or an end user. But even if Transcom were deemed to be an end-user based on Halo's definitional argument, Halo's theory would still fail. While it is true that end-users *can* originate calls, there is no support for the idea that a purported end-user must be deemed to originate every call it touches – especially when the call was started by someone else and all the purported "end-user in the middle" does is pass the call along to Halo.

II. Halo Breached The ICA By Inserting Incorrect Charge Number Data In The Call Information It Sends To AT&T.

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[1] *Northwestern Bell Order*, 2 FCC Rcd. 5986, ¶ 21 (1987); *Illinois Bell Tel. Co. v. Global NAPs Illinois, Inc.*, Docket No. 08-0105, at 24, 42 (Ill. Comm. Comm'n Feb. 11, 2009) (the ESP exemption "exempts ESPs, and *only* ESPs, from certain access charges" and does not apply to carriers that transport calls for ESPs); *Pacific Bell Tel. Co. v. Global NAPs Cal., Inc.*, D.09-01-038, Order Denying Rehearing of D.08-09-027, at 11, 2009 WL 254838, at *5 (Cal. P.U.C. Jan. 29, 2009) ("the [ESP] exemption applies only to the ESP itself, not to the carrier of ESP traffic"); *In re Petition of CLEC Coalition for Arbitration Against Southwestern Bell Telephone, L.P. d/b/a SBC Kansas*, Order No. 16, Dkt., Nos. 06-BTKT-365-ARB et al., 2005 Kan. PUC LEXIS 868 *26-27 (Kan. Corp. Comm'n 2005) ("that [ESP] exemption applies to the information service provider, not to carriers . . . that provide service to ESPs and other customers"). Thus, regardless of Transcom's purported status, there is no basis for *Halo* to claim it is exempt from access charges on the toll traffic it has been sending to AT&T.

[2] The Georgia Commission rejected Halo's reliance on *Bell Atlantic* for similar reasons. *See Georgia Halo Order* at 8.

In Section XIV.G of the ICA the parties agreed that:

> The parties will provide each other with the proper call information including all proper translations for routing between networks and any information necessary for billing where BellSouth provides recording capabilities. This exchange of information is required to enable each party to bill properly.

The exchange of accurate call detail information between interconnected carriers is essential pursuant to this provision. This information includes the phone number of the person that originated the call (the Calling Party Number, or CPN) and, in some instances, a different number for the person or entity that bears financial responsibility for the call (the Charge Number, or CN).[1] A Charge Number might be used, for example, when a business has 100 different lines for its employees but wants all calls on those lines to be billed to a single number. In that situation, calls from those 100 lines would include call detail that shows both the CPN, for the actual line that originated the call, and the Charge Number, for the billing number that will be charged for the call. When the call information includes both a CPN and a CN, the CN overrides the CPN and controls how the call is categorized and billed.[2] Specifically, the CN is used to determine the jurisdiction and rating for the call – that is, whether the call is local or non-local, and therefore whether it is subject to reciprocal compensation or access charges.

The ICA requires call information like CPN and CN to be accurate so the parties can accurately bill one another.[3] AT&T, however, discovered that until the end of 2011, Halo inserted inaccurate CNs – CNs that should not have been there at all – on every call that Halo sent to AT&T.[4] Specifically, Halo admits that it inserted a CN assigned to Transcom into the call record on every call it sent to AT&T.[5] Moreover, in every case the CN was local to (*i.e.*, in the same MTA as) the number the call was being terminated to, making the call appear to be local, and thus subject to reciprocal compensation rather than access charges – even when the call was not local.[6] For example, a call destined to Raleigh may begin in California and would therefore have a California CPN, but Halo would insert a CN that is local to Raleigh into the call information and thereby make the call appear to be local rather than long-distance.

There was no justification for Halo's insertion of a Transcom CN, because Transcom was not the financially responsible party on any of these calls. A CN is used when one party (say, an employer) takes financial responsibility for calls made by another party (say, its employee). Here, however, it is undisputed that there is no relationship between Transcom and any of the

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[1] AT&T witness Neinast Direct at 30-31, line 12–21, line 1-12.

[2] *Id.* at 31, lines 9-12.

[3] AT&T witness McPhee Direct at 22, lines 4-15.

[4] AT&T witness Neinast Direct at 31, lines 14-19.

[5] Halo witness Wiseman Testimony at 62, lines 11-14.

[6] AT&T witness Neinast Direct at 31, lines 19-32, line 2.

calling parties that made these calls,[1] and therefore Transcom is not the financially responsible party on any of these calls, because Transcom does not pay the phone bills for any of those calling parties. Halo therefore violated the ICA and industry practices for call information.

Halo tries to excuse its conduct with the same argument as on the origination issue, namely that Transcom should be deemed to originate all calls and therefore is financially responsible for them. But Transcom does not originate calls, as shown above. Furthermore, if Transcom actually originated the call, as Halo claims, its number would have shown up in the CPN field (Calling Party Number), not the CN field. The CN field is only used when a party other than the party that originated the call will be financially responsible for the call. Consequently, Halo's theory that it inserted the Transcom CN to comply with its view of how the industry treats CN is not credible. As the FCC stated, the CN field "may not contain or be populated with a number associated with an intermediate switch, platform, or gateway," yet that is what Halo did. *Connect America Order*, ¶ 714. In addition, Transcom has no relationship with any of the individuals that actually originated any of these calls, and no reason – or authorization – to have Halo insert a CN to make Transcom financially responsible for these calls originated by strangers through their own separate carriers. Thus, as the Tennessee, South Carolina, Georgia, and Missouri Commissions all concluded, Halo's insertion of a Transcom Charge Number breached the ICA.[2]

III. Halo Breached The ICA By Failing To Pay For Facilities That It Ordered Pursuant To The ICA.

This issue is different from the two issues discussed above, for it involves a simple failure of Halo to pay for facilities provided by AT&T under the ICA.

In order to interconnect with AT&T, Halo has ordered and obtained interconnection facilities from AT&T. AT&T billed Halo for those facilities, but Halo disputed those charges and refused to pay them. As of March 31, 2012, charges for these facilities remained disputed and unpaid.[3]

Halo's main defense is its theory that cost responsibility for interconnection facilities ends at the point of interconnection (POI).[4] In support of this theory, Halo details the arrangement of facilities with which it connects with AT&T at various locations and it cites various FCC rules to argue that AT&T cannot charge Halo for facilities located on AT&T's side of the POI. This argument is without merit because it relies upon the premise that the location of

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[1] Halo witness Johnson Testimony at 8, lines 15-18.

[2] *Tennessee Halo Order*, at 18; *South Carolina Halo Order* at 28-31; *Georgia Halo Order* at 11; *Missouri Halo Order* at 32.

[3] *Id.* at 24, lines 11-12.

[4] Halo witness Wiseman Testimony at 82, lines 3-8.

the POI is the sole determinant of each carrier's financial responsibility for interconnection facilities located on either side of the POI.[1]

After thoroughly examining the ICA, and reviewing the testimony and the pleadings of the parties, the Commission finds no evidence that the parties agreed that their financial obligations for interconnection facilities were to be determined by their designation of the POI. In fact, the Commission finds the contrary to be true.

In Section I of the ICA, the parties agreed that the POI would be defined as follows:

> I. Point of Interconnection (POI) is defined as the physical geographic location(s), within BellSouth's service area within a LATA, at which Parties interconnect their facilities for the origination and/or termination of traffic. This point establishes the technical interface, the test point(s), and the point(s) for operational division of responsibility between BellSouth's network and [Halo's] network

While this language clearly indicates that the POI will exist as a physical location, it does not mention nor imply that any financial obligations accompany the designation of a physical point of interconnection. See *T- Mobile USA, Inc. et al v. Armstrong et al,* 2009 WL 1424044, (E.D. Ky. May 20, 2009), where the Court held that a portion of the Commission-approved interconnection agreement between the parties, defining "interconnection point" as "a demarcation point on the incumbent network of the [RLEC] ... for the delivery of traffic pursuant to the terms and conditions of [the] Agreement" does not imply financial obligations. Thus, the Commission finds that the mere designation of the physical location of the POI in the parties' ICA does not support Halo's corresponding contention, implicit though it may be that the location of the POI is the sole determinant of the parties' financial responsibility for interconnection facilities located on either side of the POI. The Parties never reached such an agreement.

After reviewing the ICA, the testimony, pleadings and exhibits in this case, we find that the overwhelming evidence presented in this proceeding indicates that it was clearly understood that the financial responsibility was meant to be a shared responsibility that was dependent on the proportionate use of the facilities by the parties. The Commission's decision in this regard is buttressed by our review of the ICA in its entirety. For instance, Section V.B of the ICA requires AT&T and Halo to pay each other for interconnection facilities based on the proportion of the total traffic that each party sends to the other, stating:

> BellSouth and Carrier will share the cost of the two-way trunk group carrying both Parties traffic proportionally when purchased via this Agreement or the General Subscriber Services Tariff,

[1] Halo witness Wiseman Testimony at 83, lines 15-17, "The POI is where Halo's network ends. Halo has expended considerable sums to get to the POI location, which is in the AT&T tandem. AT&T is cost responsible from there." See also Wiseman Testimony at 86, lines 8-11, "IV. C establishes the "POI" concept, which serves as the location where traffic exchange occurs and where a carrier's financial responsibility for providing facilities ends and reciprocal compensation for completing the other parties' carrier's traffic begins."

> Section A35, or, in the case of North Carolina, in the North Carolina Connection and Traffic Interchange Agreement effective June 30, 1994, as amended from time to time. BellSouth will bear the cost of the two-way trunk group for the proportion of the facility utilized for the delivery of BellSouth originated Local traffic to Carrier's POI within BellSouth's service territory and within the LATA (calculated based on the number of minutes of traffic identified as BellSouth's divided by the total minutes of use on the facility), and Carrier will provide or bear the cost of the two-way trunk group for all other traffic, including intermediary traffic.

Section VI.B.2.b, in turn, states:

> BellSouth will bill Carrier for the entire cost of the facility. Carrier will then apply the BellSouth originated percent against the Local Traffic portion of the two-way interconnection facility charges billed by BellSouth to Carrier. Carrier will invoice BellSouth on a monthly basis, this proportionate cost for the facilities utilized by BellSouth.

This language clearly indicates that the apportioning of facilities costs applies for the entire facility between AT&T's switch and Halo's switch. The Commission thus finds no merit to Halo's contention that the location of the POI is the sole determinant of the financial responsibility of the parties for interconnection facilities located on either side of the POI.

Halo offers two additional defenses, but neither is persuasive. First, Halo contends that trunking costs are to be shared proportionately under the ICA only when Halo uses AT&T-supplied facilities to get to the POI.[1] That is incorrect. As Section V.B of the ICA plainly states, the apportioning of trunking costs applies "if the Parties mutually agree upon a two-way trunking arrangement."

Next, Halo contends that facilities costs are covered by reciprocal compensation charges.[2] That is wrong. Reciprocal compensation charges are per minute charges for the incremental costs incurred to transport and terminate traffic. Facilities charges, in contrast, are non-usage sensitive recurring charges for the cost of the facilities themselves.[3]

Halo admits that it ordered the facilities and trunk group elements for which AT&T seeks payment.[4] There is also no dispute that AT&T provided the facilities and trunk groups that Halo ordered.[5] Because the ICA clearly states that the costs of these interconnection facilities will be

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[1] Halo witness Wiseman Testimony at 84, lines 18-20.

[2] Halo witness Wiseman Testimony at 87, lines 14-16.

[3] AT&T witness McPhee Rebuttal at 23, lines 10-13.

[4] *See id*. at 24, lines 14-24, line 7, quoting Wiseman Testimony at 76, lines 5-8.

[5] AT&T witness McPhee Rebuttal at 24, lines 1-2.

shared based upon each carriers' proportional use, and because Halo is responsible for 100% (or nearly 100%)[1] of the traffic that has been exchanged between the parties, Halo is 100% responsible for the costs of the facilities and trunk groups.

As remedies for Halo's breaches of the ICA, the Commission grants the relief AT&T has requested. As shown above, Halo has sent landline-originated traffic to AT&T in breach of the ICA. As also shown above, a large portion of that landline traffic is non-local in nature, and AT&T either terminated that traffic for Halo, or routed Halo traffic through its tandems to subtending RLECs for termination to their end user customers. Because the landline-originated traffic was not permitted by the ICA, there are no terms in the ICA defining the proper intercarrier compensation that Halo must pay AT&T for terminating that traffic. When AT&T terminates interexchange and interstate calls for other carriers, that is access service, and those carriers must pay the access rates in AT&T's access tariffs.

There is a legal doctrine that covers what Halo has done and that makes clear that Halo must pay AT&T access charges for the non-local traffic it delivered to AT&T for termination – the "constructive ordering" doctrine. Under that doctrine, a carrier "constructively orders" service under a tariff, and therefore must pay the tariffed rate, if it (1) is interconnected in such a manner that it can expect to receive access services; (2) fails to take reasonable steps to prevent the receipt of services; and (3) does in fact receive such services.[2] The doctrine applies here, and Halo is liable to AT&T for access charges on the interstate and intrastate non-local traffic it sent to AT&T for termination.[3] The actual amount Halo must pay will be determined in bankruptcy court.

Regarding AT&T's claims for facilities charges, there is no dispute that Halo ordered interconnection facilities from AT&T and used those facilities to send traffic to AT&T. The only question is whether Halo should have to pay for the use of that equipment. As found above, the ICA requires Halo to pay for those facilities based on proportional use. The Commission therefore declares that Halo must pay the amount due for those facilities. The specific amount that Halo must ultimately pay will be determined in bankruptcy court.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of September, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Lh092712.01

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[1] AT&T witness McPhee Testimony at 26, lines 4-8.

[2] *Advamtel LLC v. AT&T Corp.*, 118 F. Supp. 2d 680, 685 (E.D. Va. 2000) (*citing United Artists Payphone Corp. v. New York Tel. Co.,* 8 FCC Rcd 5563 at ¶ 13 (1993) and *In re Access Charge Reform,* 14 FCC Rcd 14221 (1999) at ¶ 188).

[3] *Accord*, *See Tennessee Halo Order at 22; Georgia Halo Order* at 15; *South Carolina Halo Order* at 27; *Wisconsin Halo Order* at 8; *Missouri Halo Order* at 46-50.

DOCKET NO. P-35, SUB 96

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Mebtel, Inc. d/b/a CenturyLink	)	ORDER GRANTING MEBTEL'S
For Approval of a Price Regulation Plan	)	PROPOSAL FOR DISPOSITION
Pursuant to G.S. 62-133.5(a)	)	OF SERVICE QUALITY
	)	PENALTIES

BY THE COMMISSION: On January 5, 2012, Mebtel, Inc. d/b/a CenturyLink (Mebtel) filed its Confidential Annual Service Penalty Report as required pursuant to its Price Regulation Plan for the November 1, 2010 through October 31, 2011 Plan Year which included a service penalty assessment.

On February 20, 2012, Mebtel filed a Proposal for Disposition of Service Quality Penalties for the 2010/2011 Plan Year. Mebtel specified that, in lieu of issuing a one-time customer credit, it was proposing to make an unplanned and unbudgeted capital expenditure to enhance the Company's network by extending Digital Subscriber Line (DSL) service to a specific location.

By Order dated February 28, 2012, the Commission requested comments on Mebtel's Proposal.

Initial comments were filed on March 20, 2012 by the Public Staff. On March 26, 2012, Mebtel filed a letter in lieu of more formal reply comments.

PETITION

Mebtel noted that Section 11.G of its Commission-approved Price Regulation Plan states:

> If any penalties are applicable at the end of a penalty period, the Company will issue a credit on the bill of each residence and business customer of record within 90 days following the report. The amount of the credit will be determined by dividing the appropriate penalty by the number of residence and business total access lines in service at the end of the penalty period. If the calculated amount is less than $.10 per customer, no credit will be issued for that plan period, however the amount will be carried over to the next plan period. Credits will be issued once the amount per customer is equal to or greater than $.10.

Mebtel maintained that the penalty credit due to Mebtel customers for misses during the November 1, 2010 through October 31, 2011 Plan Year is a nominal amount. Therefore, Mebtel stated, it began discussing alternative remedies with the Public Staff that would provide a more substantial and tangible benefit to Mebtel's customers.

Mebtel specified that, in lieu of issuing a one-time customer credit, it was proposing to make an unplanned and unbudgeted capital expenditure to enhance the Company's network by extending DSL service to a specific location. Mebtel provided confidential information detailing the aggregate incremental capital investment for this proposed DSL expansion.

Mebtel stated that it is important to note that the designated location was not included in Mebtel's DSL capital planning projects for 2012; therefore, the investments at this site represent a substantial financial commitment above and beyond the current business plan in place for DSL expansion in Mebtel's service area. Mebtel maintained that, absent approval of Mebtel's proposal, the customers who are poised to benefit from this investment will not have Mebtel DSL service available to them for the foreseeable future. Mebtel asserted that if this proposal is approved by the Commission, Mebtel expects to make DSL service available to customers in the designated location within six (6) months of the Commission's approval of the proposal.

Mebtel maintained that the Public Staff does not object to Mebtel's Proposal.

INITIAL COMMENTS

The **Public Staff** stated in its initial comments that it has reviewed Mebtel's penalty period report and believes that the dollar amount that each Mebtel customer would receive if the penalties were issued as credits would be so small that many customers would be unlikely to notice the one-time adjustment on their monthly bills. The Public Staff maintained that instead of issuing a *de minimis* credit to each Mebtel customer, the Public Staff believes the better course would be for the Commission to allow Mebtel to apply the penalty amounts to an expansion of Mebtel's DSL deployment as proposed.

The Public Staff asserted that, in making its recommendation, it relies heavily on Mebtel's assurances that it has not allocated any 2012 capital dollars for DSL expansion into the areas identified in the Proposal.

The Public Staff further recommended that the Commission order Mebtel to file a report with the Commission detailing the areas and numbers of customers to which the projects have made DSL service available after the projects are completed. The Public Staff specified that Mebtel should also confirm in this report that the DSL expansions were completed in accordance with the Proposal, and that the costs incurred in extending DSL service to these new areas and customers equal or exceed the cost estimates furnished in the Proposal filing.

The Public Staff recommended that the Commission issue an order: (1) authorizing Mebtel to utilize the service quality penalty amounts for the twelve months ended October 31, 2011, cited on Attachment A of its Proposal, to offset the capital costs it incurs in extending DSL service into the areas identified in Attachment B of that filing; and (2) requiring Mebtel to submit a report within 30 days of completing the DSL expansion projects, providing details on the new areas and customers served by DSL and the costs Mebtel incurred in completing the DSL expansion projects identified in its Proposal.

No other party filed initial comments on Mebtel's Proposal.

REPLY COMMENTS

Mebtel stated in its letter filed in lieu of more formal reply comments that it appreciates the Public Staff's support and does not object to filing a report as proposed by the Public Staff.

WHEREUPON, based on the foregoing, the Commission finds that good cause exists to grant Mebtel's Proposal for the disposition of service quality penalty amounts due for the November 1, 2010 through October 31, 2011 penalty year as outlined in Attachment B of its February 20, 2012 Proposal in lieu of providing a one-time customer credit for the service quality penalties incurred.

In addition, the Commission finds it appropriate to require Mebtel to file a report within 30 days of completing the DSL expansion projects, providing details on the new areas and customers served by DSL and the costs Mebtel incurred in completing the DSL expansion projects identified in its Proposal.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of March, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner William T. Culpepper, III and Commissioner ToNola D. Brown-Bland did not participate in this decision.

bp032812.01

DOCKET NO. T-4418, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Joy Jessica Hall, d/b/a Joyful Movers, 106 Tapestry Terrace, Cary, North Carolina 27511 – Application for Certificate of Exemption	))))	RECOMMENDED ORDER GRANTING PROBATIONARY CERTIFICATE OF EXEMPTION WITH CONDITIONS

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Thursday, June 7, 2012, at 10:00 a.m.

BEFORE: Bruce G. Ramaekers, Hearing Examiner

APPEARANCES:

For Joy Jessica Hall, d/b/a Joyful Movers:
Joy Jessica Hall, *pro se*, 106 Tapestry Terrace, Cary, North Carolina 27511

For James G. Dunnagan, d/b/a Dunnagan's Moving & Storage:
James G. Dunnagan, *pro se*, 449 Shipyard Boulevard, Post Office Box 471, Wilmington, North Carolina 28402

For the Using and Consuming Public:
Tab C. Hunter, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

RAMAEKERS, HEARING EXAMINER: On December 21, 2011, Joy Jessica Hall, d/b/a Joyful Movers (Applicant or Company), 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 to transport household goods by motor vehicle for compensation within North Carolina.

On December 30, 2011, the Commission Staff filed a copy of a letter sent to the Applicant, dated December 29, 2011, which acknowledged receipt of the application and requested that the Applicant provide additional information to complete its application.

Also on December 30, 2011, James G. Dunnagan, d/b/a Dunnagan's Moving & Storage, Wilmington, North Carolina (C-1456), filed a protest and petition to intervene in the above-captioned docket.

On March 22, 2012, the Applicant filed the required criminal history records check performed by the Federal Bureau of Investigation (FBI).

On May 7, 2012, the Commission issued an Order granting the intervention of James G. Dunnagan (Protestant) and scheduling the matter for hearing on June 7, 2012, in Raleigh, North Carolina.

On June 7, 2012, a hearing was held in Raleigh, North Carolina, as scheduled. The Applicant, Joy Jessica Hall, appeared and represented herself pursuant to Commission Rule R1-22. The Applicant offered testimony in support of the application and responded to questions from the Public Staff, the Commission, and the Protestant. The Protestant also offered testimony and responded to questions from the Public Staff. The Public Staff offered the testimony of Carol Kimball Stahl, Director of the Transportation Rates Division, on behalf of the using and consuming public. The Hearing Examiner, pursuant to G.S. 62-65, took judicial notice of the transcript of the complaint and show cause proceeding held on April 26, 2012, in Docket No. T-4418, Sub 1.

On June 20, 2012, the Protestant filed his suggested proposal denying certificate of exemption.

On June 28, 2012, the Public Staff filed its Proposed Recommended Order.

Based upon the information contained in the application, the testimony received at the hearing, and the entire record in this matter, the Hearing Examiner now makes the following

FINDINGS OF FACT

1. Joy Jessica Hall is the sole owner of Joyful Movers, located in Cary, 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 to transport household goods by motor vehicle for compensation within North Carolina.

2. On April 30, 2009, in Docket No. T-4418, Sub 0, the Applicant filed an application for a certificate of exemption to transport household goods; however, no certificate of exemption was issued by the Commission. That docket was closed on March 8, 2010.

3. On December 21, 2011, in Docket No. T-4418, Sub 2, the Applicant filed an application for a certificate of exemption to transport household goods; including the required confidential FBI criminal history records check. Prior to the close of the hearing in this matter, the Applicant provided proof of insurance to the Hearing Examiner of vehicle liability, cargo, and general liability as required by law and Commission rules and regulations.

4. The Applicant currently has two trucks and the necessary equipment to engage in the intrastate transportation of household goods and has more than six years of experience in the moving industry. Such experience includes, but is not limited to, managing the day-to-day operations of the Company, supervising crews, and performing moving services.

5. The Applicant attended a Maximum Rate Tariff No. 1 (MRT) training seminar on February 23, 2012.

6. The Applicant has engaged in the intrastate transportation of household goods without a certificate of exemption since assuming ownership of Joyful Movers in 2009 from Donald Haley and has used the revenues derived from performing full-service moves and non-regulated services, such as labor-only moving services and moves conducted exclusively within a gated community, to support her eight children.

7. The Commission initiated a show cause proceeding in Docket No. T-4418, Sub 1, after David Loewy, PhD filed a formal complaint alleging that his household goods were damaged by the Applicant during the intrastate transportation of his household goods by motor vehicle for compensation without a certificate of exemption on June 23 and June 30, 2011, from Cary, North Carolina, to Wilmington, North Carolina.

8. The Better Business Bureau of Eastern North Carolina (BBB) has assigned an "F" rating to Joyful Movers and shows three complaints against the Applicant, including the one from Dr. David Loewy.

9. The Applicant has performed labor-only moving services since the show cause hearing on April 26, 2012.

10. The Applicant has no business or operations management plan for Joyful Movers but does have federal and state tax identification numbers and pays employer taxes for two full-time employees.

11. The Applicant should be granted a probationary certificate of exemption with conditions.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

The Applicant testified that she has two vehicles[1] and the equipment necessary to provide household goods services. She also testified that she has more than six years of management experience in the moving industry, including but not limited to, managing the day-to-day operations of a moving company and supervising crews. In addition, the Applicant stated that she has also performed loading and unloading services. Ms. Hall commented that she had attended an MRT training seminar on February 23, 2012, and learned a lot of new things, but that she plans to attend another MRT training seminar in the future to familiarize herself with all of the Commission's rules and regulations. She explained that childcare assistance from her parents and Donald Haley allows her to manage Joyful Movers from her rental home while attending to her eight children.[2] The Applicant further stated that she does not have a business plan for Joyful Movers, but she does have federal and state tax identification numbers and pays employer taxes for two full-time employees.

[1] In the application, Ms. Hall stated that she owns a 2001 Chevy Express 3500. At the June 7, 2012 hearing Ms. Hall testified that she had since purchased, with cash, in February 2012, a 1996 24-foot International box truck.

[2] Ms. Hall testified that some of her children attend school during the day and the younger children are at home with her during the day.

The Applicant acknowledged that this was not the first time that she had filed an application for a certificate or exemption. She stated that she assumed ownership of Joyful Movers from Donald Haley[1] in 2009 and filed an application for a certificate of exemption in Docket No. T-4418, Sub 0, but she did not complete the prior application process because of domestic relationship issues.

The Applicant admitted to knowingly performing intrastate household goods moves without a certificate after assuming ownership of Joyful Movers in 2009, including the household goods move that was the subject of a formal complaint by Dr. Loewy in Docket No. T-4418, Sub 1, after the Applicant failed to resolve his damage claim. In that proceeding, Ms. Hall testified that Joyful Movers should not have performed the household goods move for Dr. Loewy and acknowledged that it should be fined. She further agreed that performance of the move without a certificate of exemption was unfair to certificated carriers.

In regard to that formal complaint proceeding in Docket No. T-4418, Sub 1, on July 13, 2012, the Commission issued an Order Ruling on Complaint and Show Cause Proceeding. Such Order required, among other things, that Joyful Movers not be issued a certificate of exemption by the Commission until the monetary penalties assessed in that proceeding have been paid in full to the Commission. On August 1, 2012, the Commission issued an Order Ruling Penalty Satisfied and Closing Docket stating that on July 31, 2012, Joyful Movers had filed with the Commission four money orders in the total amount of $1,500. Consequently, the Commission declared that the Company had fully satisfied the $1,500 penalty levied by the Commission on July 13, 2012 and closed that docket.

With respect to the "F" rating assigned by the BBB, on cross-examination the Applicant testified that the BBB lowered the Company's "A-" rating after the Public Staff Transportation Rates Division informed the BBB that the Company was not properly certified. The Applicant maintained that, according to a report from the BBB dated May 10, 2012, the specific factor that lowered the Company's rating was the failure to have a required competency license. Ms. Hall acknowledged that the May 10, 2012 Report included two other complaints in addition to Dr. Loewy's complaint but the Applicant commented that the Company's prior "A-" rating did include Dr. Loewy's complaint.

The Applicant testified that she has advertised and performed labor-only moving services since the complaint and show cause proceeding held on April 26, 2012. She further testified that she hopes to obtain a certificate of exemption and is willing to improve her relationships with the Commission, the Public Staff's Transportation Rates Division, and the certificated movers. She also testified that if she were to be granted a probationary or temporary certificate of exemption, she would be willing to operate within the parameters of such certificate. Prior to the close of the hearing in this matter, the Applicant provided proof of insurance to the Hearing Examiner of vehicle liability, cargo, and general liability as required by law and Commission rules and regulations.

[1] Ms. Hall testified that in 2005 when she was laid off from her full-time job she assisted Mr. Haley, her domestic partner and the father of her children, with his moving business. Ms. Hall stated that during the four years between 2005 and 2009 when she assisted Mr. Haley, he operated his moving business without a certificate of exemption.

The Protestant, Mr. Dunnagan, testified that his concern was with labor-only movers taking jobs away from certificated movers and that his purpose in testifying was to point out to the Commission the Applicant's shortcomings and the need for more training. He also testified as to his belief that, if granted some level of certificate of exemption, the Applicant should follow through with additional training and education; and he stated that he would be willing to help her.[1]

Public Staff witness Stahl recommended that the Commission grant Joyful Movers a time-limited probationary certificate of exemption for six months with conditions. Ms. Stahl expressed concern that Ms. Hall should take responsibility for transporting household goods only in those instances where her crews are capable of doing correct packing of boxes and trucks and the safe transport of household goods from Point A to Point B. She stated that having two trucks should give Ms. Hall the opportunity to do good-size moves, which would give her good revenue to conduct a business. She further stated that she would like to see Ms. Hall concentrate initially on hourly moves, which under the MRT rules are moves of 35 miles or less between origin and destination, and that the Applicant could gradually start doing weight-distance moves upon a showing by Ms. Hall of no significant complaints or damage claims, the ability to handle the paperwork and give appropriate estimates, and the ability of her crews and equipment to handle the transport. She also indicated that Ms. Hall may need guidance from other moving companies in making this transition.

Further, witness Stahl testified that with probationary certificates issued in the past, the conditions were satisfied and eventually the conditions and the probationary status were removed and that such a procedure would be useful in this matter. However, if the company presents problems by not satisfying claims, not performing safe moves, or not handling the business properly, it would be in violation of the certificate, which could be lost altogether.

In addition, witness Stahl also testified that Ms. Hall should refrain from doing regulated/jurisdictional moves until she has obtained the Commission's bill of lading, the addendum to the bill of lading, and the brochure. She recommended that for a period of 30 days, Ms. Hall should provide to the Public Staff's Transportation Rates Division the paperwork for moves conducted for review to determine if it is being completed correctly. Further, witness Stahl recommended that until the Commission rules on her application in this docket, Ms. Hall should state in her advertisings, offerings, and postings that "We are a labor-only company, which means we cannot drive a truck loaded with someone's household goods." Regarding Mr. Haley's role with Joyful Movers, witness Stahl recommended that Mr. Haley, as well as any other persons responsible for the business in Ms. Hall's absence, be required to attend an MRT training seminar.

Finally, witness Stahl expressed her belief that Ms. Hall is now prepared to improve her relationships with the Commission, the Public Staff, and the moving industry; and that she would

[1] On June 20, 2012, the Protestant filed his proposal recommending that the Applicant's request for a certificate of exemption be denied for lack of fitness, knowledge, or skills; that she cease and desist from operating any business organized and advertised for the purpose of intrastate transportation of household goods; and that she include notice on all advertisements that "We are a labor-only company."

be willing to assist Ms. Hall in making proper decisions regarding her ability to be a certificated mover on any level.

Based upon the foregoing, the Hearing Examiner concludes that Joy Jessica Hall has satisfactorily addressed the issue of her fitness to obtain a certificate of exemption. However, the Hearing Examiner is of the opinion that the Applicant needs further training and experience prior to performing weight-distance moves. Further, the Hearing Examiner believes that in order to enhance the Applicant's ability to give appropriate estimates; to ensure the completion of the proper paperwork; and to ensure the proper transport of household goods, guidance, and oversight by the Public Staff is needed for a period of time. In addition, the Hearing Examiner agrees with the Public Staff that Ms. Hall should attend a second MRT training seminar and that a person empowered to manage the Company in her absence should attend a MRT training seminar as well. Consequently, the Hearing Examiner finds and concludes that Joy Jessica Hall, d/b/a Joyful Movers, should be granted a probationary certificate of exemption with conditions.[1] The Hearing Examiner finds and concludes that such probationary certificate of exemption should include certain conditions that would require the Applicant to gradually demonstrate the capability of performing complex moves; to designate a qualified employee to serve in a managerial capacity when the Applicant is unavailable; to develop a reasonable and adequate level of knowledge of the MRT and the laws, rules, and regulations governing the moving industry; and to maintain a level of accountability that is expected of certificated carriers. Therefore, the Hearing Examiner finds and concludes that the following conditions should be imposed:

(1) Joyful Movers shall conduct only hourly-rated moves of 35 miles or less between the customer's origin and destination. This provision shall remain in effect until such time as the Commission issues an order granting a non-probationary certificate of exemption, issues an order modifying the conditions, or cancels the Applicant's authority to perform household goods moves within North Carolina.

(2) At the completion of each move, Joyful Movers shall provide a copy of all paperwork associated with the move, either via facsimile or attached to an email, sent to the designated person within the Public Staff's Transportation Rates Division. The paperwork will include, at a minimum, the completed and signed Uniform Household Goods Bill of Lading and the Addendum to the Uniform Household Goods Bill of Lading; and an Estimated Cost of Services form will be provided if a written estimate was requested by the customer. This provision shall remain in effect until such time as the Public Staff's Transportation Rates Division determines that it is no longer necessary or no more than 180 days from the date of this Order, whichever occurs first.

(3) Joyful Movers shall make contact information for each customer readily available to allow the Public Staff's Transportation Rates Division to contact any customer in its discretion to determine the quality of the service rendered to the customer. This provision shall remain in

[1] The Hearing Examiner notes that this incremental approach addresses several of the concerns raised by the Protestant. The Hearing Examiner encourages Mr. Dunnagan and his colleagues in the moving industry to assist Ms. Hall, when reasonably possible, in meeting the conditions attached to the probationary certificate.

effect until such time as the Public Staff's Transportation Rates Division determines that it is no longer necessary or no more than 180 days from the date of this Order, whichever occurs first.

(4) Joyful Movers shall ensure that all damage claims by its customers are submitted in writing to Joyful Movers and to the Public Staff's Transportation Rates Division on a form provided by the Public Staff's Transportation Rates Division. This provision shall remain in effect until such time as the Public Staff's Transportation Rates Division determines that it is no longer necessary or no more than 180 days from the date of this Order, whichever occurs first.

(5) Joy Jessica Hall shall designate a person empowered to manage the Company in her absence, should it become necessary, and shall require that person to attend an MRT training seminar within 60 days of the granting of the probationary certificate of exemption. Ms. Hall shall also attend a second MRT training seminar within 120 days from the date of this Order.

(6) Joy Jessica Hall shall provide the full legal names of the two full-time employees working for Joyful Movers to the Public Staff's Transportation Rates Division.

The Hearing Examiner is of the opinion that the additional training, oversight, and guidance to be provided by the Public Staff for a brief duration of time as a result of the aforementioned conditions should provide reasonable assurance that the Applicant should be able to maintain the level of service and accountability that is expected of certificated movers.

IT IS, THEREFORE, ORDERED as follows:

1. That Joy Jessica Hall, d/b/a Joyful Movers, is hereby granted a probationary certificate of exemption and authorized to transport household goods within North Carolina under the conditions attached to this certificate of exemption.

2. That the probationary certificate of exemption shall be subject to the six conditions as set forth above in this Order, which shall be attached to the probationary certificate.

3. That this probationary certificate of exemption shall remain in effect until such time as the Commission issues an order granting a non-probationary certificate of exemption, issues an order modifying the conditions, or cancels the Applicant's authority to perform household goods moves in North Carolina.

4. That Joyful Movers shall immediately cease using any forms, agreements, etc., previously used in its negotiations with its customers and shall use only documents required or approved by the Commission. Confirmation of the acquisition of the Uniform Household Goods Bill of Lading, the Addendum to the Uniform Household Goods Bill of Lading, and the mandatory brochure as well as the Estimated Cost of Services form for written estimates shall be provided to the Public Staff's Transportation Rates Division in a manner satisfactory to that office.

5. That 90 days after the date of this Order the Public Staff shall file a status report with the Commission regarding Joyful Mover's compliance with these conditions and confirming that Ms. Hall's designee has attended the MRT training seminar. The status report shall also provide a recommendation as to whether or not Joyful Movers should be permitted to provide moves of greater than 35 miles between the customer's origin and destination.

6. That 120 days from the date of this Order the Public Staff shall file a final report to the Commission with a recommendation as to whether or not Joy Jessica Hall, d/b/a Joyful Movers, should be granted a non-probationary certificate of exemption. Such report shall also provide confirmation that Ms. Hall has attended a second MRT training seminar.

7. That Joy Jessica Hall, d/b/a Joyful Movers, shall abide by the tariff requirements as established by the Commission and adopted in its Maximum Rate Tariff No. 1.

8. That Joy Jessica Hall, d/b/a Joyful Movers, shall properly perform the service of household goods transportation within North Carolina in accordance with this Order and shall obtain a reasonable and adequate knowledge of the rules and regulations governing the moving industry, including the safety requirements as enforced by the North Carolina Division of Motor Vehicles.

9. That Joy Jessica Hall, d/b/a Joyful Movers, shall sustain financial solvency and furnish adequate service on a continuing basis by maintaining the required insurance protection, by maintaining safe and dependable equipment, and by settling any damage claims which may arise in accordance with the provisions of the MRT.

10. That Joy Jessica Hall, d/b/a Joyful Movers, shall maintain and have on file with the North Carolina Division of Motor Vehicles cargo insurance and vehicle liability coverage as required by law and Commission rules and regulations.

11. That Joy Jessica Hall, d/b/a Joyful Movers, shall maintain and have on file with the Commission's Operations Division a certificate of general liability insurance coverage in the minimum amount of $50,000.

12. That Joy Jessica Hall, d/b/a Joyful Movers, shall maintain the Company's books and records in such a manner that all of the applicable items of information required in the prescribed Annual Report to the Commission can be used by the Applicant in the preparation of such Annual Report. A copy of the Annual Report form shall be furnished upon request made to the Public Staff's Transportation Rates Division at 919-733-7766.

13. That Joy Jessica Hall, d/b/a Joyful Movers, shall maintain the Company's books and records in such a manner that all of the applicable items of information requested in its prescribed quarterly Public Utilities Regulatory Fee Report can be used by the Applicant in the preparation of such report and the payment of the quarterly regulatory fee. Any questions regarding the regulatory fee report and/or regulatory fee should be directed to the Commission's Fiscal Management and Administrative Division at 919-733-5265.

14. That all vehicles, whether owned or leased, and used by Joy Jessica Hall, d/b/a Joyful Movers, in the Company's household goods operations must be identified with the Company's name, city, state, and certificate of exemption number (such probationary certificate of exemption number is C-2541) on both sides, and on the rear, left upper quadrant, of each vehicle in letters not less than three (3) inches high.

15. That this Order shall constitute a probationary certificate of exemption until formal probationary Certificate of Exemption No. C-2541 has been issued and transmitted to the Applicant, along with a copy of Maximum Rate Tariff No. 1.

ISSUED BY ORDER OF THE COMMISSION.
This the 9th day of August, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

br080912.02

DOCKET NO. T-4445, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Allen Botnick, 3437 Glasson Street, Apt. H, Durham, North Carolina 27705, Complainant	)	RECOMMENDED ORDER DISMISSING COMPLAINT AND RULING ON SHOW CAUSE PROCEEDING
v.	)	
Lawrence Eugene Hinnant, III, d/b/a First Class Move, Respondent	)	

HEARD: Wednesday, June 27, 2012, at 9:30 a.m., in the Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Corrie V. Foster, Commission Staff Hearing Examiner

APPEARANCES:

For Allen Botnick:

No appearance

For Lawrence Eugene Hinnant, III, d/b/a First Class Move:

Lawrence Eugene Hinnant, III, *pro se*, 4705-B Walden Pond, Raleigh, North Carolina 27604

The Using and Consuming Public:

Tab C. Hunter, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Dobbs Building, Raleigh, North Carolina 27699-4326

BY THE HEARING EXAMINER: On February 17, 2012, Allen Botnick (Complainant), filed a complaint with the Commission against Lawrence Eugene Hinnant, III, d/b/a First Class Move (First Class Move or Respondent), alleging that First Class Move operated illegally as an uncertificated mover, committed fraud, and damaged his household goods (HHG) during a move on August 6, 2011.

On February 21, 2012, the Commission issued an order serving the complaint on First Class Move that directed First Class Move to either satisfy the demands of the Complainant or to file an answer to the complaint with the Commission on or before March 7, 2012.

On March 14, 2012, Commission Staff filed a copy of electronic mail (e-mail) sent to First Class Move regarding its failure to respond to the complaint.

On March 20, 2012, First Class Move sent a responsive e-mail to Commission Staff asserting that he had not received the Commission's Order Serving Complaint.

On March 21, 2012, the Commission served its Reissuing Order Serving Complaint on First Class Move via United States Certified Mail, return receipt requested, and by e-mail that directed First Class Move to either satisfy the demands of the Complainant or to file an answer to the complaint with the Commission on or before April 6, 2012.

On April 18, 2012, the Commission's Reissuing Order Serving Complaint served on First Class Move at 4705-B Walden Pond, Raleigh, North Carolina 27604, was returned to the Commission's Chief Clerk's Office by the United States Postal Service as unclaimed.

On May 31, 2012, the Commission issued an Order Scheduling Show Cause Hearing. In the Order, the Commission scheduled the hearing for Wednesday, June 27, 2012, and stated that it had reviewed its records of certificates of exemption to move HHG and determined that First Class Move's application for a certificate of exemption was granted on September 9, 2011, in Docket No. T-4445, Sub 0, and assigned certificate number C-2523. The Commission's Order further stated that, according to Commission records, First Class Move has a mailing address of 4705-B Walden Pond, Raleigh, North Carolina 27604, and an e-mail address of firstclassmove@aol.com.

Accordingly, the Commission ordered Lawrence Eugene Hinnant, III, d/b/a First Class Move to appear and show cause:

(a) Why First Class Move should not be found to have willfully failed to respond to the Commission's Reissuing Order Serving Complaint dated March 21, 2012;

(b) Why First Class Move should not be found to be a de facto public utility by holding itself out as a common carrier of HHG, as defined in G.S. 62-3(7), by engaging in intrastate commerce as set forth in G.S. 62-3(15);

(c) Why First Class Move should not be found to have performed an intrastate transportation 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, by performing a move of HHG in Raleigh, North Carolina, for Allen Botnick on August 6, 2011; and

(d) Why First Class Move, for its actions, should not be subject to sanctions or penalties provided by G.S. 62-310(a), recoverable pursuant to G.S. 62-312, and/or have its license plates revoked/suspended pursuant to G.S. 62-278(a).[1]

The Commission ordered the Public Staff to participate in the hearing on behalf of the using and consuming public and to prosecute the show cause. The Order Scheduling Show Cause Hearing was served on First Class Move by United States Certified Mail, return receipt requested and e-mail notification.

On June 11, 2012, First Class Move filed an answer and motion to dismiss. In its answer, First Class Move stated that Mr. Botnick's damage claim was satisfied with a cashier's check for the judgment amount and the associated court costs decreed in the civil action filed by Mr. Botnick in the courts of Wake County, North Carolina. The Respondent testified that he was unaware he needed to respond to the Commission because the Wake County courts had entered a judgment for the damages to Mr. Botnick's household goods and he regretted his failure to comply with Commission requirements.

On June 19, 2012, the Complainant filed a reply stating that, although the answer filed by First Class Move was not completely satisfactory, he was not requesting a hearing on the matter at the present time. The Complainant did, however, request that the Commission keep the docket open for at least six (6) months, so the matter could be monitored by the Complainant, the Commission, and the Public Staff.

The complaint and show cause came on for hearing as scheduled. The Hearing Examiner declared that the complaint matter had been resolved, denied the Complainant's motion to hold the docket open for six (6) months, and ruled that evidence would be received for the issues in the show cause proceeding. The following persons testified: Lawrence Eugene Hinnant, III, the Respondent and owner of First Class Move; and Cynthia K. Smith of the Public Staff's Transportation Rates Division. The Complainant, Allen Botnick, did not appear at the hearing.

Based on the information contained in the application, the testimony at the hearing and the entire record in this matter, the Hearing Examiner makes the following

FINDINGS OF FACT

1. The Commission has authority pursuant to G.S. 62-3(23)a.4 to regulate common carriers by motor vehicle engaged in intrastate commerce to transport HHG for the public for compensation, as defined by G.S. 62-3(7) and (15).

2. The Commission has authority to issue certificates of exemption to applicants for the purpose of intrastate transportation of HHG for compensation in North Carolina pursuant to G.S. 62-261(8) and Commission Rule R2-8.1 and to issue sanctions and/or monetary penalties pursuant to G.S. 62-278(a) and G.S. 62-310(a) for willfully violating any provision of Chapter 62 or for the willful violation of any lawful rule or regulation of the Commission and engaging in the

[1] G.S. 62-278(a) authorizes the revocation and removal of the license plates from the vehicles of any carrier of persons or household goods by motor vehicle for compensation for willful violation of any provision of Chapter 62, or for the willful violation of any lawful rule or regulation made and promulgated by the Utilities Commission.

intrastate transportation of HHG for compensation without having been granted a certificate of exemption, respectively.

3. Lawrence Eugene Hinnant, III, d/b/a First Class Move was granted a certificate of exemption from the Commission on September 9, 2011, in Docket No. T-4445, Sub 0, and assigned certificate number C-2523.

4. First Class Move's official mailing address is 4705-B Walden Pond, Raleigh, North Carolina 27604, and the e-mail address is firstclassmove@aol.com.

5. First Class Move operates two (2) motor vehicles with license plates issued by the North Carolina Division of Motor Vehicles (DMV), a 1996 Freightliner FL70 and a 1997 International 4700. First Class Move owns another 1997 International that has not been issued license plates by the DMV.

6. First Class Move engaged in the intrastate transportation of HHG for compensation in North Carolina without a certificate of exemption on or about August 6, 2011, on behalf of Allen Botnick.

7. On August 18, 2011, Allen Botnick was issued a conditional credit in the amount of $159.00 by his credit card company for disputed charges levied by First Class Move.

8. On January 19, 2012, Allen Botnick was granted a judgment for damages to his personal property from a Wake County Civil magistrate, against Lawrence Eugene Hinnant, III, in the amount of $732.38.

9. First Class Move filed a copy of a cashier's check from Regions Bank dated June 11, 2012, with its answer and motion to dismiss in the amount of $1,002.88. The cashier's check was made payable to the Wake County Sheriff. This was evidence that First Class Move had satisfied the judgment for the damages to Mr. Botnick's household goods entered by the Wake County courts.

10. The Public Staff recommended that First Class Move should be assessed a penalty of $1,000 for performing a HHG move on behalf of Allen Botnick within North Carolina without a certificate of exemption, as required by G.S. 62-261(8) and Commission Rule R2-8.1.

DISCUSSION OF THE EVIDENCE

Witness Cynthia K. Smith of the Public Staff's Transportation Rates Division testified on direct examination that her duties and responsibilities include investigating complaints involving motor carriers that perform intrastate HHG moves. Witness Smith stated that she was familiar with First Class Move and was aware that the Commission issued Lawrence Eugene Hinnant, III, d/b/a First Class Move a certificate of exemption on September 9, 2011.

Witness Smith stated that First Class Move's application for a certificate of exemption listed two (2) trucks: a 2000 Hyundai and a 2002 Chevrolet. The Respondent testified that First

Class Move now operates a 1996 Freightliner FL70 and a 1997 International 4700 as motor vehicles bearing license plates issued by the North Carolina Division of Motor Vehicles. The Respondent further testified that First Class Move owns another truck, a 1997 International that has not been issued license plates by the North Carolina Division of Motor Vehicles.

Witness Smith testified that she was notified by Allen Botnick in an e-mail dated August 16, 2011, that his household goods had been damaged during a move performed by First Class Move on or about August 6, 2011. Witness Smith further testified that she sent Mr. Botnick an e-mail requesting additional information about the move and the damages. Witness Smith stated that she received the requested information from Mr. Botnick in an e-mail dated August 23, 2011. She further stated that she subsequently contacted First Class Move regarding Mr. Botnick's complaint in an e-mail dated August 25, 2011, and that First Class Move responded to her e-mail on August 26, 2011. Witness Smith testified that Mr. Botnick filed a formal complaint with the Commission on February 17, 2012, alleging that the Respondent performed a HHG move for Mr. Botnick on August 6, 2011.

The Respondent testified that he filed an answer to the complaint on June 11, 2012, after realizing that First Class Move needed to comply with the Commission's Order. The Respondent also testified that his failure to comply with the Commission's Order to file an answer to the complaint was not willful but excusable neglect due to his confusion as to whether the court's authority outweighed that of the Commission. He stated he mistakenly believed that since he had already been served by the Wake County courts, the matter would be resolved with the courts. The Respondent testified that First Class Move performed the HHG move for Allen Botnick on or about August 5th or 6th of 2011 and acknowledged that the Commission had not granted First Class Move a certificate until September 9, 2011. The Respondent further testified that the Complainant received a credit for $159 and that First Class Move satisfied the judgment for damages to the Complainant's household goods with a Regions Bank cashier's check made payable to the Wake County Sheriff in the amount of $1,002.88.

Public Staff witness Smith recommended that First Class Move should be assessed a penalty of $1,000 for performing the move for Mr. Botnick without a certificate of exemption. Witness Smith also testified that she would like to see First Class Move do better at resolving its claims in a timely manner and in accordance with the procedures established by the Commission.

During cross-examination by Mr. Hinnant, Public Staff witness Smith testified that another formal complaint had been filed against First Class Move by Crystal Simpson. The Respondent testified that no date for a public hearing had been set for the complaint filed by Crystal Simpson, and First Class Move has taken steps to improve its processes and more effectively handle complaints. The Respondent stated that First Class Move has hired people who have been in the industry for years and has a designated employee to handle complaints. The Respondent further testified that he considered a $1,000 penalty to be a "heavy" fine but believes that First Class Move could pay the penalty in two weeks if permitted to do so.

CONCLUSIONS

Since January 1, 2003, movers of household goods in intrastate commerce in North Carolina have been required to obtain a certificate of exemption from the Commission pursuant to G.S. 62-261(8), before beginning to provide such services. The Commission has long since recognized that the status of an entity as a public utility does not depend upon whether it has obtained operating authority from the Commission, but rather upon whether it is in fact operating a business defined as a public utility by the General Statutes. State ex. rel. Utilities Commission v. Carolina Telephone and Telegraph Co., 267 N.C. 257 (1966); State ex. rel. Utilities Commission v. Mackie, 79 N.C. App. 19 (1986), modified and aff'd, 318 N.C. 686 (1987). As stated in the Commission's Order to Cease and Desist and to Assess Penalties, issued July 27, 2009, in Docket No. T-4422, Sub 0, the Commission "has been unequivocal about its exercise of authority" over motor carriers of household goods and "has looked squarely at the actions of noncertificated movers to find jurisdiction."

Based on the foregoing findings of fact and the entire record in this proceeding, the Hearing Examiner concludes that First Class Move should be subject to sanctions and penalized as provided in G.S. 62-310(a), for violating state statutes and Commission Rules based on the following:

(1) holding itself out to the public as a common carrier of household goods engaged in intrastate commerce as set forth in G.S. 62-3(7) and G.S. 62-3(15) and operating as a *de facto* public utility on or about August 6, 2011, without having been issued a certificate of exemption from the Commission; and

(2) performing intrastate transportation of HHG for compensation on behalf of Allen Botnick within North Carolina without a certificate of exemption on or about August 6, 2011, as required by G.S. 62-261(8) and Commission Rule R2-8.1.

The Hearing Examiner further finds and concludes that First Class Move's failure to respond to the Commission's Reissuing Order Serving Complaint dated March 21, 2012, was not willful but the result of excusable neglect and, therefore, First Class Move should not be subject to sanctions or penalties as provided by G.S. 62-310(a), recoverable pursuant to G.S. 62-312, and/or have its license plates revoked/suspended pursuant to G.S. 62-278(a).

The Hearing Examiner also finds and concludes that First Class Move shall submit copies of all damaged claims filed by customers to the Public Staff's Transportation Rates Division within 48 hours of its submission to First Class Move to ensure complaints and/or claims are being resolved in accordance with Commission requirements. This process shall be in effect for 90 days from the date of this Order. In accordance with the statement made by the Respondent, the designated employee responsible for handling customer complaints and damage claims shall attend an MRT training seminar within four (4) months of the date of this Order.

The Hearing Examiner is, therefore, of the opinion that First Class Move should be assessed a penalty of $1,000 payable in certified funds or United States currency to the Commission as one payment or in twelve (12), equal monthly installments into the Office of the Chief Clerk, commencing thirty (30) days following the issuance of this Order and every subsequent thirty (30) days thereafter until satisfied. The Hearing Examiner further opines that the $1,000 penalty is a just and reasonable settlement of the show cause issues and violations and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the complaint filed by Allen Botnick is hereby dismissed.

2. That pursuant to G.S. 62-310(a), Lawrence Eugene Hinnant, III, d/b/a First Class Move, shall remit in United States currency or certified funds to the Commission (made payable to the North Carolina Department of Commerce/Utilities Commission) a penalty in the amount of $1,000, as one payment or in twelve (12) equal monthly installments into the Office of the Chief Clerk, commencing thirty (30) days following the issuance of this Order and every subsequent thirty (30) days thereafter until said $1,000 is paid in full, for operating as a de facto public utility by holding himself out as a common carrier of HHG, as set forth in G.S. 62-3(7), and by engaging in intrastate commerce as set forth in G.S. 62-3(15), by performing intrastate transportation of HHG for compensation in North Carolina, without a certificate of exemption, as required by G.S. 62-261(8) and Commission Rule R2-8.1.

3. That Lawrence Eugene Hinnant, III, d/b/a First Class Move shall submit a copy of all damage claims to the Public Staff's Transportation Rates Division within 48 hours of its submission to First Class Move to ensure complaints and/or claims are being resolved in accordance with Commission requirements. This process shall be in effect for 90 days from the date of this Order.

4. That the person within First Class Move designated to handle customer complaints shall attend an MRT training seminar within four (4) months of the date of this Order.

5. That the Chief Clerk shall serve this Order on the Respondent by United States Certified Mail, return receipt requested and e-mail.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of September, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Cf092612.01

DOCKET NO. T-4418, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of David Loewy, 2316 South 17th Street, Suite 140, PMB 401, Wilmington, North Carolina, 28403, Complainant v. Joy Jessica Hall and Donald Haley, d/b/a Joyful Movers, Respondent	ORDER RULING ON COMPLAINT AND SHOW CAUSE PROCEEDINGS

HEARD: Thursday, April 26, 2012, 10:00 a.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Bryan E. Beatty, Presiding; Commissioner ToNola D. Brown-Bland, and Commissioner Lucy T. Allen

APPEARANCES:

For the Complainant:

James C. Thornton, Parker Poe Adams & Bernstein, LLP, Wachovia Capital Center, 150 Fayetteville Street, Suite 400, Raleigh, North Carolina 27601

For the Public Staff:

Tab C. Hunter, Staff Attorney, Public Staff - North Carolina Utilities Commission, Dobbs Building, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

For the Respondents:

Joy Jessica Hall and Donald Haley, d/b/a Joyful Movers, Pro se 106 Tapestry Terrace, Cary, North Carolina 27511

BY THE COMMISSION: On November 29, 2011, David Wesley Loewy (Complainant) through his attorney Ashley Culbreath Council, filed a complaint with the Commission against Joy Jessica Hall and Donald Haley, d/b/a Joyful Movers (Respondents), alleging that the Respondents damaged his belongings while operating as an uncertificated mover. According to the Complainant, Joyful Movers performed a household goods (HHG) move for him from Cary, North Carolina to Wilmington, North Carolina, in June of 2011 and caused in excess of $60,000 worth of damages to his personal property. Complainant also requested relief pursuant to House Bill 311 which became effective on October 1, 2011.

On the same day, the Commission issued an Order Serving Complaint and served the complaint on Respondents and directed Respondents to either satisfy the demands of the Complainant or to file an answer to the complaint with the Commission.

On December 19, 2011, Respondent Joy Jessica Hall on behalf of Joyful Movers filed an answer to the complaint. In the pleading, Ms. Hall admitted that Joyful Movers performed the move of household goods for compensation for Complainant on June 23, 2011, from Cary to Wilmington, but denied any liability for the alleged damages to Complainant's personal property. Ms. Hall further asserted that HB 311 was not yet in effect when Joyful Movers performed the move in June of 2011 and therefore, the move that Joyful Movers performed would not have been in violation of House Bill 311 at that time.

On December 20, 2011, the Commission issued an Order Serving Answer and requested Complainant to advise the Commission by January 6, 2012, whether Ms. Hall's answer was acceptable or if he was requesting a public hearing on his complaint.

On January 4, 2012, attorney Ashley Culbreath Council filed a notice of withdrawal as attorney for the Complainant. On January 6, 2012, attorney James C. Thornton filed a letter to notify the Commission that he had been retained to represent the Complainant and requested an extension of time to reply to the Commission Order issued on December 20, 2011. On January 6, 2012, the Commission issued an Order granting the request for extension of time until February 5, 2012.

On February 3, 2012, Complainant, through his counsel, filed notice with the Commission and requested a hearing in order to present evidence in support of his complaint.

On February 29, 2012, the Commission issued an Order Scheduling a Show Cause Hearing for April 3, 2012. Respondents were requested to appear and show cause why they should not be found to have operated as a de facto public utility in the State of North Carolina in June and July of 2011, by operating as a moving company within North Carolina without a certificate of exemption from the Commission, and why they should not be subject to sanctions provided by statute, including monetary penalties levied by the Commission.

Ms. Hall and Mr. Haley were further ordered to appear before the Commission to show cause why they should not be found to have violated House Bill 311, now G.S. 62-280.1, by advertising their services as a household goods carrier in the November 2011 edition of Outreach NC magazine without first having been issued a certificate of exemption from the Commission and why they should not be subject to sanctions as provided by statute, including penalties levied by the Commission.

The Order scheduled the hearing for Tuesday, April 3, 2012, at 9:30 a.m., Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina; directed the Public Staff - North Carolina Utilities Commission to participate in the hearing on behalf of the using and consuming public and prosecute the show cause proceeding; and ordered the Chief

Clerk to serve a copy of the Order and the attached 2 exhibits from the November 2011, Vol. 2, Issue 11 of Outreach NC (Cover page and page #33), on Joy Jessica Hall and Donald Haley, d/b/a Joyful Movers, by means of United States Certified Mail, return receipt requested.

On March 5, 2012, the Clerk's office filed notice that the certified mail return receipt for the Commission's February 29, 2012 order was delivered to Respondent Joy Jessica Hall on March 1, 2012.

On March 16, 2012, Complainant filed a Motion for Continuance of the Hearing. On March 27, 2012, the Commission issued an Order Rescheduling Hearing for April 26, 2012, 10:00 a.m. in Raleigh.

On April 26, 2012, the matter came on to be heard before the Commission. In attendance at the hearing were Respondents Joy Jessica Hall and Donald Haley, pro se; Tab C. Hunter, Public Staff Legal Division and Public Staff witness Carol Stahl; the Complainant David Loewy; and Complainant's counsel, James C. Thornton. The Complainant and Public Staff submitted exhibits and documents to the record and the Public Staff submitted the affidavit of Gail L. Mount, Chief Clerk of the Commission.

Based upon the testimony and the exhibits presented at the hearing, and the entire record in this proceeding, 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 (HHG) for compensation in North Carolina, as defined by G.S. 62-3(7) and (15).

2. The Commission has authority to issue Certificates of Exemption to applicants for the purpose of intrastate transportation of HHG for compensation in North Carolina, pursuant to G.S. 62-261(8) and Commission Rule R2-8.1.

3. Ms. Joy Jessica Hall and Donald Haley are properly before the Commission, pursuant to Commission Rule R1-4(3).

4. Ms. Joy Jessica Hall is the owner and/or operator of Joyful Movers, for the purpose of intrastate transportation of HHG, for compensation in North Carolina. Mr. Donald Haley is the supervisor of Joyful Movers' moving crews.

5. The Commission has never issued a Joyful Movers a certificate of exemption to transport household goods in the State of North Carolina in the name of Joy Jessica Hall, Donald Haley or Joyful Movers.

6. Ms. Hall submitted an application for a certification with the Commission on April 30, 2009 in Docket No. T-4418, Sub 0. However, the application was never completed and was withdrawn in 2010.

7. Respondent Joy Jessica Hall, d/b/a Joyful Movers, acted as a de facto public utility by holding itself out as a common carrier of HHG, as defined in G.S. 62-3(7), by engaging in intrastate commerce as set forth in G.S. 62-3(15). Respondent Donald Haley was not an owner or operator of Joyful Movers.

8. Respondent Joy Jessica Hall, d/b/a Joyful Movers provided Mr. Loewy with a quote of $1,600.00 for a move of a four bedroom[s] fully furnished home.

9. On June 23, 24 and 30th, 2011, Respondent Joy Jessica Hall, d/b/a Joyful Movers engaged in the intrastate transportation of the household goods of David Loewy for compensation from a residence in Cary, North Carolina, to a residence in Wilmington, North Carolina without a certificate of exemption, as required in G.S. 62-261(8) and Commission Rule R2-8.1.

10. The Commission does not have jurisdiction to order Respondent to pay Mr. Loewy for damages which he alleges were caused by Respondents.

11. House Bill 311 codified in § 62-280.1(a)(1) states, in pertinent part, that it is unlawful for a person not certificated to operate as a carrier of household goods…in print, or by sign, including the use of … magazine…or in any other manner, directly or by implication, represent that the person holds a certificate or is otherwise authorized to operate as a carrier of household goods in this State.

12. Respondent Joy Jessica Hall, d/b/a Joyful Movers, violated G.S. 62-280.1, by advertising its services in the November 2011- Vol. 2, Issue 11 of Outreach NC, as a household goods carrier to the public without first having been issued a certificate of exemption from the Commission.

EVIDENCE AND CONCLUSION FOR FINDINGS OF FACT NOS.1 AND 2

The evidence to support the findings of fact can be found in G.S. 62-3, the Commission records, and Commission Rule R2-8.1.

It has long been determined that the Commission has authority to regulate motor carriers of household goods as "public utilities." G.S. 62-3(23)a.4. This authority also extends to persons and/or entities that may not have specifically met all of the Commission's authorization requirements. The Commission has previously stated:

> The status of an entity as a public utility does not depend upon whether it has obtained operating authority from the Commission, but rather upon whether it is in fact operating a business defined as a public utility by the General Statutes. State ex rel. Utilities Commission v. Carolina Telephone and Telegraph Co., 267 N.C. 257 (1966); State ex rel. Utilities Commission v. Mackie, 79 N.C. App. 19 (1986), modified and aff'd, 318 N.C. 686 (1987). "If an entity is, in fact, operating as a public utility, it is subject to the regulatory powers of the Commission notwithstanding the fact that it has failed to comply with G.S. 62-110 before beginning its operation" Mackie, 79 N.C. App., at 32. The

> same conclusion applies when an entity is required to obtain a certificate of exemption from the Commission, but fails to do so. (quoting, In Weathers Bros. Transfer Co, Inc. d/b/a Weathers Moving and Distribution v. Movers at Demand, Inc, Docket Nos. T-4176, Sub 1 and T-4171, Sub 2 (May 11, 2004)).
>
> (See NCUC Docket No. T-4422, Sub 0, July 27, 2009.)

Commission Rule R2-8.1 sets forth the specific requirements which are needed in order to obtain a certificate of exemption from the Commission. These requirements are also on the applications which the Commission provides to prospective applicants.

In order to obtain a certificate of exemption, an applicant must demonstrate to the Commission that it is fit, willing, and able to properly perform the service of household goods transportation within the North Carolina, is familiar with the moving industry, has a reasonable and adequate knowledge of the rules and regulations governing the moving industry, including safety requirements as enforced by the N.C. Division of Motor Vehicles, and has knowledge of and will abide by the tariff requirements as established by the Commission in Maximum Rate Tariff No. 1. An applicant must also show that it is financially solvent, maintain minimum limits of liability and cargo insurance coverage, file proof of general liability insurance, permit only persons possessing a valid driver's license to operate the motor vehicles that will be used for transporting household goods, submit a Federal certified criminal record check, and certify that the applicant has valid authorization to work in the United States.

After carefully considering the evidence in these findings of fact, the Commission concludes that it has jurisdiction over regulated public utilities as well as "de facto" public utilities. The Commission further concludes that it is solely responsible for issuing certificate of exemptions to applicants that have successfully met the prescribed requirements.

EVIDENCE AND CONCLUSION FOR FINDINGS OF FACT NO. 3

Respondents Hall and Haley appeared at the hearing and did not contest the jurisdiction of the Commission to decide this matter.

EVIDENCE AND CONCLUSION FOR FINDINGS OF FACT NO. 4

The evidence for this finding of fact can be found in the testimony of Complainant Mr. Loewy and Respondent Ms. Hall.

In his testimony, Mr. Loewy stated that he negotiated the terms and details of the move primarily with Ms. Hall. These negotiations with her occurred over the telephone and via electronic mail (e-mail). Although Mr. Loewy never met Ms. Hall face-to-face, he assumed that she was in control because she made all the important decisions such as the estimate and the scheduling of the move.

Mr. Loewy also described that he was present at the Wilmington residence on June 24, 2011, when Joyful Movers delivered his goods. He stated that it was Mr. Haley with whom he dealt when Joyful Movers off-loaded the furniture. It was Mr. Haley who directed the

Joyful Movers' personnel when they off-loaded the furniture from the truck and into the residence.

Ms. Hall in her direct testimony confirmed that Mr. Haley serves as the "supervisor of the crews" and "facilitate[s] the actual physical moves." Ms. Hall, on the other hand, is the owner of the business and handles most of the administrative responsibilities. According to Ms. Hall, she took over the business in 2009 from Mr. Haley who initially started the business with a friend around 2005. She has been running the business since then.

No party offered direct testimony contesting the Respondent's positions within the business. Therefore, in the absence of any direct testimony to the contrary, the Commission concludes that Respondent Joy Jessica Hall is the owner/operator of Joyful Movers, while Respondent Donald Haley is the supervisor of Joyful Movers' moving crew.

EVIDENCE AND CONCLUSION FOR FINDINGS OF FACT NOS. 5 AND 6

The evidence to support these findings of fact can be found in the testimony of witness Stahl, the affidavit of witness Gail Mount, and the testimony of Respondent Hall.

It is uncontested that Joyful Movers has never possessed a certificate to transport household goods in the State of North Carolina. Witness Stahl who has worked in the Public Staff – N.C. Utilities Commission's Transportation Rates Division since 2002, testified that she had never been made aware of a certificate being issued to Joyful Movers. According to witness Stahl, it is her job as Director of Transportation Rates Division to remain informed of the certificates that are issued by the Commission. She has consistently reviewed the list of certificates that are issued by the Commission, and Joyful Movers has never been included on any lists of entities possessing a certificate of exemption. However, she did testify that she was aware that Ms. Hall filed an application for a certificate of exemption back in 2009, but did not complete it. Witness Stahl also testified that she is aware that Ms. Hall submitted another application in December 2011.

The Public Staff also presented an affidavit from witness Gail L. Mount, Chief Clerk of the Commission which was admitted into evidence. As Chief Clerk, Ms. Mount is the custodian of the Commission's official records. In Ms. Mount's affidavit she attested that she researched the Commission's records of certificates of exemption and was able to confirm that the Commission has never issued a certificate in the name of Joy Jessica Hall, Donald Haley or Joyful Movers.

Ms. Hall admitted in her direct testimony that she has never possessed a certificate of exemption from the Commission to move household goods. Ms. Hall further testified that she did submit an application in 2009. However, she did not follow through with it and it was eventually withdrawn.

After carefully considering the evidence in these findings of fact, the Commission concludes that the Commission never issued a certificate of exemption to Respondent Joy Jessica Hall or Joyful Movers. The Commission further concludes that the Respondent submitted an application in 2009, but it was withdrawn in 2010.

EVIDENCE AND CONCLUSION FOR FINDINGS OF FACT NOS. 7, 8, AND 9

The evidence supporting these findings of fact is found in the testimony of Complainant Loewy, the testimony of Respondent Hall, and Complainant's Hearing Exhibit #1.

The facts and circumstances show that Respondent Joy Jessica Hall, d/b/a Joyful Movers consistently held herself out as an authorized mover to the general public. Mr. Loewy testified that he became aware of Ms. Joy Jessica Hall and Joyful Movers while planning to move his residence from 108 Gwinnet Place, Cary, North Carolina to 2302 Parham Drive, Wilmington, North Carolina, Mr. Loewy further testified that he conducted research on moving companies on the internet and discovered Joyful Movers' advertisement on Craigslist. According to Mr. Loewy, Joyful Movers described itself in its advertisement as a carrier of household goods.

Mr. Loewy received competitive bids from several moving carriers and settled on Joyful Movers. According to his testimony, Mr. Loewy selected Joyful Movers for the following reasons:

> Ms. Hall was very forthcoming with answering my questions; being able to do the move in the time I needed it done; and they were not the least expensive, but they were within $20 of --- (sic) of the least expensive. And it was a comfortability (sic) feeling among other things.

Mr. Loewy testified that Joy Jessica Hall arranged and coordinated the move of his household goods. According to Mr. Loewy, the early planning for the move occurred between Ms. Hall and Mr. Loewy's assistant, Shelley Murdoch. Initially, Mr. Loewy was unavailable and delegated the planning to Ms. Murdoch. Ms. Murdoch was responsible for overseeing the Cary end of the move. Mr. Loewy indicated that he never had a face to face meeting with Ms. Hall. However, he did have communications with Ms. Hall via e-mail and several telephone calls. During their communications, they discussed the specifics of the pending move. Mr. Loewy further testified that he explained to Ms. Hall that he worked out of his home and there was office equipment. Additionally, he informed her that he had "two attics that were relatively full of goods." He specifically remembers informing Ms. Hall that he possessed a lot of artwork, but did not describe any one particular piece.

Mr. Loewy requested that Ms. Hall or another representative of Joyful Movers visit his home in Cary to perform an estimate for a move of "a four bedroom[s] fully furnished home." Ms. Hall scheduled a time when she or a representative of Joyful Movers would visit Mr. Loewy's Cary residence to conduct an assessment of his furniture in order to provide him with a quote for the move. However, the appointment was cancelled by Mr. Loewy due to a business conflict. The cancelled appointment was never rescheduled and Ms. Hall did not visit the residence to conduct a visual estimate for the move.

Mr. Loewy was never provided with any Commission-approved documentation such as a bill of lading or other forms to acknowledge the move. Instead, Ms. Hall quoted Mr. Loewy a flat rate of $1,600.00 over the telephone. The quote was eventually memorialized in an e-mail sent to Mr. Loewy. Mr. Loewy submitted a copy of the e-mail as an exhibit during his testimony. Mr. Loewy also received a copy of Joyful Movers' certificate of liability insurance.

Mr. Loewy stated in his testimony that Joyful Movers packed his household goods from the Cary residence on June 23, 2011, and transported the goods to Wilmington using two Ryder rental trucks the next day. He was present at the residence in Wilmington on June 24, 2011, when Mr. Haley arrived to off-load the furniture. He also testified that Joyful Movers performed a second trip the next week on June 30, 2011, from Cary to Wilmington to move additional furniture. Despite a second trip from Cary, Joyful Movers failed to move remaining amount of Mr. Loewy's furniture to Wilmington.

Joy Jessica Hall's actions of operating without a certificate as a de facto public utility were without regard to the Commission's rules and regulations. The testimony showed that Ms. Hall acted with the knowledge that she needed a certificate from the Commission to operate in the state. The move performed by Ms Hall for Mr. Loewy was a "full service move." Ms. Hall was entirely responsible for boxing, loading and transporting Mr. Loewy's household goods from Cary to Wilmington.

In her direct testimony, Ms. Hall admitted to the Commission that Joyful Movers' employees moved Mr. Loewy's goods at a time that she was not certificated to conduct moves. Specifically, Ms. Hall stated "I'm not saying that I did not perform the move without a certificate. We did. And we knew we shouldn't have done it." This fact was further highlighted during Complainant's cross examination, in which Ms. Hall stated that "I knew that we should have been certificated and held a certificate" when she was asked if she knew at the time she spoke with Mr. Loewy regarding the move that it should not have been done. Ms. Hall further testified that she should be fined for her actions that were undertaken while Joyful Movers was uncertificated because her actions have brought harm to certificated carriers that are following the rules. Ms. Hall became aware of the Commission's requirements to obtain a certificate in 2009 and she submitted an application, but did not follow up with a request by the Commission for additional information. The application was eventually withdrawn.

The law allows the Commission to address unlawful or unapproved actions by public utilities that violate the laws set-forth in Chapter 62. Specifically, § 62-310 (a) states that any public utility which violates any provision of this Chapter or refuses to conform to or obey any rule or regulation of the Commission shall… 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. 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.

Therefore, after carefully considering the evidence, the Commission concludes that Respondent Joy Jessica Hall, d/b/a Joyful Movers acted willfully as a de facto public utility by performing a move without authorization from the Commission. The Commission also determines that $1,000 is a reasonable penalty to assess Respondent Joy Jessica Hall, d/b/a Joyful Movers for her operation without a certificate.

EVIDENCE AND CONCLUSION FOR FINDINGS OF FACT NO. 10

The evidence supporting this finding of fact is found in the testimony of Complainant Loewy.

During his testimony, Mr. Loewy spoke extensively and in detail about the damages to his personal property. Specifically, he asserted that several pieces of valuable artwork, furniture and personal effects were damaged to the tune of $61,000.00. According to Mr. Loewy many of the items were not wrapped or boxed properly. As a result of the negligent packing, he asserted that some of his most valued possessions were either nicked or scratched in transit.

Although Mr. Loewy did pay Joyful Movers the initial flat rate of $1,600.00, he refused to pay an additional $600 expense for boxes or other costs because he was dissatisfied with the damage that occurred to his items. According to Mr. Loewy, he incurred over $60,000 worth of damage to his personal property.

In an effort to recoup his damages, Mr. Loewy filed a claim against Joyful Movers' insurance carrier, Nautilus Insurance Company. His claim with Nautilus was denied. Nautilus provides Joyful Movers with general liability coverage not cargo insurance. Nautilus' general liability insurance did not cover Mr. Loewy's personal property.

Mr. Loewy testified that he learned from witness Stahl that the Commission would not be able to order the payment of damages to him. However, this would not preclude Mr. Loewy from seeking relief in the appropriate Court of General Justice.

After careful consideration of the evidence, the Commission concludes that it does not possess jurisdiction over Mr. Loewy's damages claim against Respondent Joy Jessica Hall, d/b/a Joyful Movers because the Commission cannot render a judgment for compensatory damages.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NOS. 11 AND 12

The evidence for these findings of fact is found in the testimony of witness Stahl, and Respondent Ms. Hall.

Witness Stahl testified that she was personally aware of several Joyful Movers' advertisements

> I'm aware of some postings that were done to Craigslist. In those, they were done at other dates. And I have some copies of some of those postings that offered moving services on Craigslist. They were done when she had full knowledge that she should not be asking or offering the services of a full service move.

Witness Stahl testified that as early as 2009, she had "many conversations with Ms. Hall." According to witness Stahl, these conversations revolved around the content in the advertisements that Ms. Hall had placed on Craigslist. Witness Stahl advised Ms. Hall several times in 2009 and 2010 that Joyful Movers could not operate without a certificate of exemption issued by the Commission and that she was restricted in the content of information placed in her advertisements.

Witness Stahl also testified that she contacted Ms. Hall via e-mail in August 2011, to advise her about House Bill 311, now G.S. 62-280.1, and its specific restrictions on uncertificated carriers. Witness Stahl advised Ms. Hall that her current advertisements on

Craigslist must be revised to eliminate the impression or suggestion that Joyful Movers is certified and/or conducts full service moves.

Despite several warnings from witness Stahl, Ms. Hall chose not to pull the advertisement that was scheduled to run in the November 2011, Vol. 2, Issue 11 of Outreach NC. Instead, Ms. Hall admitted in her testimony that she contracted with Outreach NC to run the advertisement in question in November 2011. Ms. Hall testified that she did not believe she violated G.S. 62-280.1. In her testimony, Ms. Hall stated "I did not put up there that we were full service and I didn't have that we were certified or anything licensed."

The Commission has reviewed Joyful Movers' advertisement and does not find Ms. Hall's argument persuasive. In reviewing the advertisement in question, it clearly states "Moving? Downsizing? ... Happy to move you Anytime, Anywhere!" There is no mention of labor only services in the text of the advertisement. The advertisement further states that Joyful Movers is "Family Owned & Operated since 2005." The words in the text and the picture of a truck can lead a reasonable person to the conclusion that Joyful Movers is an authorized carrier of household goods and has been engaging in moves since 2005. The Commission concurs with witness Stahl's statement "that Joyful Movers could have revised all of its advertisements to clearly state that it provides just labor or include some other language that would place the general public on notice that Joyful Movers was not an authorized carrier of household goods."

The Commission can take action against a person or entity that unlawfully advertises and holds themselves out as a certificated carrier while not possessing the authorization to do so. Specifically, § 62-280.1(a)(1) states, in pertinent part, that it is unlawful for a person not certificated to operate as a carrier of household goods…in print, or by sign, including the use of … magazine…or in any other manner, directly or by implication, to represent that the person holds a certificate or is otherwise authorized to operate as a carrier of household goods in this State. The law became effective on October 1, 2011.

After carefully considering the evidence, the Commission concludes that Respondent Joy Jessica Hall, d/b/a Joyful Movers violated this statute by posting the advertisement in Outreach NC magazine in November 2011. Subsection (c) of the above statute 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 Commission determines that $500 is a reasonable penalty to assess Respondent for her violation of this statute.

FURTHER CONCLUSIONS

After carefully considering the testimony, exhibits, and pleadings regarding Joyful Movers' actions, the Commission finds and concludes that Respondent Joy Jessica Hall, d/b/a Joyful Movers actions were *willful and without regard* to the authority of the Commission. Pursuant to G.S. 62-310 (a) and G.S. 62-280.1(c), the Commission specifically, finds and concludes as follows:

1. That Respondent Joy Jessica Hall, d/b/a Joyful Movers shall pay a penalty of **$1,000** in certified funds (made payable to the North Carolina Department of Commerce/Utilities Commission) to the Commission, Office of the Chief Clerk, for operating as a de facto public utility

by holding itself out as a common carrier, as set forth in G.S. 62-3(7), by engaging in intrastate commerce as set forth in G.S. 62-3(15), and by performing intrastate transportation of HHG for compensation in North Carolina, without a Certificate of Exemption, as required by G.S. 62-261(8) and Commission Rule R2-8.1;

2. That Respondent Joy Jessica Hall, d/b/a Joyful Movers shall pay a penalty of **$500** in certified funds (made payable to the North Carolina Department of Commerce/Utilities Commission) to the Commission, Office of the Chief Clerk, for its violation of G.S. 62-280.1(c), by unlawfully advertising in the November 2011 publication of Outreach NC;

3. That Respondent Joy Jessica Hall, d/b/a Joyful Movers shall immediately cease and desist operations until it fully complies with the Commission's monetary penalties and is assigned a Certification of Exemption by this Commission;

4. That the Commission will seek to recover the $**1,500** total penalty in an action instituted in the Superior Court of Wake County, North Carolina, pursuant to G.S. 62-310(a), should Respondent Joy Jessica Hall, d/b/a Joyful Movers fail to remit the payment within 30 days of this Order.

5. That Respondent Joy Jessica Hall, d/b/a Joyful Movers shall not be issued a Certificate of Exemption by the Commission until all said monetary penalty is paid to the Commission; and

6. That Respondent Joy Jessica Hall, d/b/a Joyful Movers shall be served this Order via United States Postage Service certified mail, return receipt requested.

ISSUED BY ORDER OF THE COMMISSION.
This the __13th__ day of July, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Julie Kennedy, Acting Deputy Clerk

Cf071312.02

DOCKET NO. W-1044, SUB 19

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Bradfield Farms Water Company, 2335 Sanders Road, Northbrook, Illinois 60062 for Authority to Increase Rates for Water and Sewer Utility Service in All of Its Service Areas in Cabarrus and Mecklenburg Counties, North Carolina	)	ORDER APPROVING STIPULATION AND GRANTING RATE INCREASE

HEARD IN: Charlotte-Mecklenburg Government Center, Room 267, 600 E. Fourth Street, Charlotte, North Carolina, on Tuesday, October 2, 2012

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Thursday, November 15, 2012

BEFORE: Commissioner Bryan E. Beatty, Presiding, and Commissioners Susan W. Rabon and Lucy T. Allen

APPEARANCES:

For Bradfield Farms Water Company

Christopher J. Ayers, Poyner Spruill, LLP, 301 Fayetteville Street, Suite 1900, Raleigh, North Carolina 27602-1801

For the Using and Consuming Public

Gina C. Holt, Staff Attorney, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On June 29, 2012, Bradfield Farms Water Company (Bradfield Farms or Applicant) filed an application with the Commission for authority to increase in its water and sewer rates in all of its service areas in Cabarrus and Mecklenburg Counties in North Carolina. By Order issued July 17, 2012, the Commission declared the matter to be a general rate case pursuant to G. S. 62-137; suspended the proposed new rates for up to 270 days pursuant to G. S. 62-134; scheduled the application for public hearing in Charlotte, North Carolina, and for evidentiary hearing in Raleigh, North Carolina; and required customer notice of the proposed rate increase and hearings.

On August 6, 2012, the Applicant filed its Certificate of Service stating under oath that the required customer notice was mailed to all affected customers.

On September 7, 2012, Mr. William R. Colyer filed a letter with the Commission seeking to intervene in this docket on behalf of Bradfield Farms Homeowners Association (BFHOA).

On September 13, 2012, Mr. Colyer filed a revised letter requesting to intervene as an individual customer of Bradfield Farms.

On September 14, 2012, the Commission issued an Order denying the request by Mr. Colyer to intervene on behalf of BFHOA and allowing Mr. Colyer to intervene on his own behalf as a customer of Bradfield Farms.

On September 26, 2012, Bradfield Farms filed the direct testimony of Regulatory Accountant Mike Kulov in support of the application.

On October 2, 2012, a public hearing was held in Charlotte, North Carolina, for the purpose of receiving customer testimony. No customers presented testimony at the hearing.

On October 12, 2012, a partial settlement agreement between Bradfield Farms and the Public Staff was filed with the Commission in this docket. In the agreement, Bradfield Farms and the Public Staff agreed on the capital structure and the rate of return for Bradfield Farms, waived the filing of all direct, supplemental and rebuttal rate of return testimonies by Bradfield Farms and the Public Staff, and waived the right to cross-examine each other's rate of return witnesses, if any.

On November 2, 2012, the Public Staff filed an Agreement and Stipulation of Settlement (Stipulation) as to all issues between those Bradfield Farms and the Public Staff in this matter. Attached to the Stipulation were Exhibit I and Exhibit II summarizing the operating revenues, operating revenue deductions, rate base, and rate of return that the Applicant and the Public Staff agreed are appropriate for use in this proceeding. Attached as Appendix A was a Schedule of Rates showing the rates and charges intended to produce total annual operating revenue requirements for Bradfield Farms' water and sewer operations. The parties to the Stipulation also agreed that all prefiled testimony may be introduced into evidence without objection, and waived their respective rights to cross-examine all witnesses who prefiled testimony.

On November 9, 2012, Bradfield Farms filed a Motion for Order Excusing Witness from Hearing requesting that witness Mike Kulov be excused from appearing in-person at the evidentiary hearing.

On November 9, 2012, Mr. William Colyer, the only other party in this docket, filed a letter with the Commission in which he consented to the terms of the Stipulation filed on November 2, 2012. In addition, Mr. Colyer waived his right to cross-examine any of Bradfield Farms' witnesses.

On November 14, 2012, the Commission issued an Order Granting Motion to Excuse Witness and Admitting Prefiled Testimony and Exhibit into Evidence.

The matter came on for hearing in Raleigh, North Carolina, on November 15, 2012, as scheduled. No customers presented testimony at the hearing. Pursuant to the Stipulation, the testimony of Mike Kulov was copied into the record as if given orally from the witness stand and the exhibits of the witness were admitted into evidence. The Application for General Increase in

Rates filed with the Commission on June 29, 2012, the Partial Settlement Agreement filed with the Commission on October 12, 2012, the Stipulation filed jointly on November 2, 2012, and Mr. Colyer's November 9, 2012, letter to the Commission were also submitted as exhibits. Ms. Gina Casselberry provided testimony on behalf of the Public Staff in response to questions raised by the Commission.

On the basis of the application, the Stipulation, the records of the Commission and the evidence in the record, the Commission makes the following

FINDINGS OF FACT

1. Bradfield Farms is a corporation organized under the laws of the State of North Carolina and is a franchised utility providing water and sewer utility service to customers in Cabarrus and Mecklenburg Counties, North Carolina. Bradfield Farms is a wholly owned subsidiary of Utilities, Inc.

2. Pursuant to its franchise, Bradfield Farms provides service to 965 water customers and 970 sewer customers in Bradfield Farms Subdivision and sewer-only service to 160 customers in the Larkhaven Subdivision. Bradfield Farms also provides bulk sewer service to 510 residences in the Silverton and Woodland Farms Subdivisions and apartments in Vista Park.

3. The overall quality of water and sewer utility service provided by Bradfield Farms is adequate.

4. Bradfield Farms is properly before the Commission pursuant to G. S. 62-133 and 62-134 and Commission Rule R1-17 for a determination of the justness and reasonableness of its proposed rates and charges for its water and sewer operations in all of its service areas in North Carolina.

5. The test period for purposes of establishing rates in this proceeding is the twelve months ended September 30, 2011.

6. Bradfield Farms' present and proposed rates are as follows:

	Present	Proposed
Monthly Water Rates:		
Base charge per month, zero usage	$ 7.72	$ 10.80
Usage charge, per 1,000 gallons	$ 1.82	$ 2.55
Monthly Sewer Rates:		
Residential Customers Flat Rate, per month	$ 21.97	$ 30.02
Bulk Flat Rate, per customer per month	$ 20.84	$ 28.48

Bulk Sewer Service for Vista Park Apartments

Base charge, per month per REU	$ 20.84	$ 28.48

7. Bradfield Farms' total annual operating revenues under present rates are as follows:

Water Operations: $241,681
Sewer Operations: $395,038

8. Bradfield Farms requested an increase in rates that would produce the following additional revenues:

Water Operations: $85,437
Sewer Operations: $143,691

9. Bradfield Farms' original cost rate base for use in this proceeding is as follows:

Water Operations: $359,617
Sewer Operations: $262,854

10. Bradfield Farms had water plant in service of $838,182 and sewer plant in service of $1,040,499 at the end of the test year, including pro forma adjustments.

11. The accumulated depreciation related to Bradfield Farms' plant in service at the end of the test year, including pro forma adjustments, was $255,045 for water operations and $283,128 for sewer operations.

12. The contributions in aid of construction (CIAC), net of accumulated amortization, collected by Bradfield Farms as of the end of the test year were $77,761 for water operations and $340,543 for sewer operations.

13. Bradfield Farms' total operating revenue deductions under present rates are as follows:

Water Operations: $227,747
Sewer Operations: $426,563

14. Bradfield Farms' total operating revenue deductions under the stipulated rates are:

Water Operations: $238,084
Sewer Operations: $438,557

15. The total rate case costs for this proceeding are $73,253. These costs should be amortized over three years, resulting in an annual rate case expense of $24,418.

16. It is reasonable and appropriate to calculate: regulatory fees using the statutory rate of 0.12%; gross receipts taxes using the statutory rates of 4% for water operations and 6%

for sewer operations; and state and federal income taxes using the corporate rates of 6.9% for state income taxes and 34% for federal income taxes.

17. The appropriate rate of return components to be used in this proceeding are 50.42% long-term debt with an embedded cost of debt of 6.60% and a common equity ratio of 49.58% with a return on common equity of 9.80%, resulting in an overall weighted return of 8.19%.

18. It is appropriate to determine the revenue requirement for Bradfield Farms using the rate base method as allowed by N.C. Gen. Stat. § 62-133.

19. Bradfield Farms should be allowed to increase its rates and charges so as to produce the following revenues:

	Service Revenues	Other Revenues & Uncollectibles	Total Operating Revenues
Water Operations	$239,628	$27,896	$267,524
Sewer Operations	$457,829	$ 2,247	$460,076
Combined Operations	$697,457	$30,143	$727,600

20. The annual revenue levels set forth above will provide Bradfield Farms with the opportunity to earn a return on operating revenue deductions of 8.19%.

21. The rates and charges agreed to by Bradfield Farms and the Public Staff are intended to produce total annual operating revenues of $267,524 for water operations and $460,076 for sewer operations. These rates and charges are as follows:

Monthly Water Rates:

Base charge per month, zero usage	$ 8.66
Usage charge, per 1,000 gallons	$ 2.04

Sewer Utility Service (excluding Vista Park Apartments):

Residential Customers Flat Rate, per month	$25.62
Bulk Flat Rate, per month per customer	$24.30

Bulk Sewer Service for Vista Park Apartments:

Bulk Flat Rate, per month per REU	$24.30

New Water Customer Charge:	$27.00
New Sewer Customer Charge:	$27.00

Water Reconnection Charge:

If water cut off by utility for good cause or at the customer's request and there is no cut-off valve on customers' service line	Actual cost to istall cut-off valve

Returned Check Charge: $25.00

22. On April 27, 2012, the Commission issued an Order Approving Transfer, Cancelling Franchise and Requiring Customer Notice in Docket No. W-1044, Sub 18 wherein it approved Bradfield Farms' transfer of the sewer collection system in the Woodbury Subdivision in Mecklenburg County, North Carolina to the City of Charlotte and its utility department Charlotte-Mecklenburg Utilities ("CMU"). Pursuant to a filing in Docket W-1044, Sub 18 on July 10, 2012, Bradfield Farms notified the Commission that the transfer was completed on July 2, 2012. The wastewater collection system will be connected to CMU's wastewater collection system once CMU completes construction of facilities for interconnection. In the interim, CMU purchases bulk wastewater service from Bradfield Farms at the Commission-approved bulk sewer rate of $20.84/month/residence.

23. The Stipulation contains a provision wherein the Parties agree that the rates and charges for sewer operations shall go into effect on the later of: (1) when the City of Charlotte has ceased receiving sewer service from Bradfield; or (2) the Commission has issued an order approving the rates and charges for sewer service as shown on the attached Appendix A. Bradfield agrees to provide the Public Staff and the Commission five days written notice of the date Charlotte ceases receiving sewer treatment service.

24. The Stipulation contains a provision that states the Parties have agreed that any recommended order approving rates and charges agreed to in the Stipulation may become the final order of the Commission upon issuance, and they waive the right to file exceptions to the recommended order.

25. The Stipulation contains a provision that states the Parties have agreed to waive the right to appeal from a final order of the Commission approving the Stipulation.

26. The Stipulation contains a provision that states the Parties have agreed none of the positions, treatments, figures, or other matter reflected in said Stipulation 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 matter at issue.

Whereupon, the Commission reaches the following

CONCLUSIONS

Based upon the foregoing findings of fact and the entire record in this proceeding, the Commission is of the opinion, and so concludes, that the provisions of the Stipulation between Bradfield Farms and the Public Staff filed on November 2, 2012, are just and reasonable and should be approved and that Bradfield Farms should be authorized to adjust and increase its rates for all of its service areas as provided in the Stipulation effective for service rendered on and after the date of this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation between Bradfield Farms and the Public Staff entered and filed on November 2, 2012, is hereby approved.

2. That Bradfield Farms is authorized to increase its rates and charges for water and sewer utility service in all of its service areas in North Carolina, effective for service rendered on and after the date of this Order, provided that the rates and charges for sewer operations shall go into effect on the later of: (1) when the City of Charlotte has ceased receiving sewer service from Bradfield; or (2) the Commission has issued an order approving the rates and charges for sewer service as shown on the attached Appendix A. Bradfield shall provide the Public Staff and the Commission five dates written notice of the date Charlotte ceases receiving sewer treatment service as a bulk customer.

3. That the Schedule of Rates attached as Appendix A is approved and deemed to be filed with the Commission pursuant to G. S. 62-138.

4. That a copy of the Notice to Customers attached as Appendix B be mailed with sufficient postage or hand delivered to all affected customers in each relevant service area and that the Applicant submit the attached Certificate of Service properly signed and notarized not later than 45 days after the date of this Order.

ISSUED BY ORDER OF THE COMMISSION
This the _18th_ day of _December_, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

rb121712.01

APPENDIX A
PAGE 1 OF 3

SCHEDULE OF RATES

for

BRADFIELD FARMS WATER COMPANY

for providing water and sewer utility service in

BRADFIELD FARMS SUBDIVISION

in Cabarrus and Mecklenburg Counties, North Carolina

WATER AND SEWER – CERTIFICATE

for providing sewer only service in

LARKHAVEN SUBDIVISION

and for providing bulk sewer utility service in

SILVERTON AND WOODLAND FARMS SUBDIVISIONS AND
VISTA PARK APARTMENTS

in Cabarrus and Mecklenburg Counties, North Carolina

Metered Water Utility Service:

Base charge, zero usage	$ 8.66 per month
Usage charge, per 1,000 gallons	$ 2.04

Sewer Utility Service:

Residential Customer Flat Rate	$25.62 per month
Bulk Flat Rate	$24.30 per month per customer

Bulk Sewer Service for Vista Park Apartments:

Base charge	$24.30 per month per REU [1/]

(To be collected from Vista and delivered to Bradfield Farms Water Company for treatment of Vista wastewater)

New Water Customer Charge:	$27.00
New Sewer Customer Charge: [2/]	$27.00

Disconnection/Reconnection Charges: [3/]

Water

If water service is cut off by utility for good cause or at the customer's request, and the customer has a cut-off valve on customer's service line	$27.00
If water service is cut off by utility for good cause or at the customer's request, and	Actual cost to install

there is no cut-off valve on customer's service line [4/]	cut-off valve

Sewer

If sewer service is cut off by utility for good cause and:

A.	The customer is also a water customer of the Company	No charge
B.	The customer is not water customer of the Company [4/]	Actual cost to install sewer plug

Bills Due:	On billing date
Bill Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Returned Check Charge:	$25.00
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bill still past due 25 days after billing date

NOTES:

1/ 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.

2/ This charge shall be waived if sewer customer is also a water customer within the same service area.

3/ Customers who have been disconnected and are reconnected a the same address within nine months of disconnection will be charged the monthly base charge or the monthly flat rate per month for the period during which they were disconnected.

4/ Company shall notify the customer the estimated cost of disconnecting service at the time Notice of Disconnection is provided to customer.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1044, Sub 19, on this the _18th_ day of _December_, 2012

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX B

DOCKET NO. W-1044, SUB 19

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Bradfield Farms Water Company,	)	
2335 Sanders Road, Northbrook, Illinois 60062	)	
for Authority to Increase Rates for Water and	)	NOTICE TO CUSTOMERS
Sewer Utility Service in All of Its Service Areas	)	
in Cabarrus and Mecklenburg Counties, North	)	
Carolina	)	

Notice is hereby given that the North Carolina Utilities Commission has issued an Order authorizing Bradfield Farms Water Company to increase water and sewer rates in Cabarrus and Mecklenburg Counties by approximately 14% overall.[1] The new approved rates are as follows:

Monthly Water Rates:	
Base charge per month, zero usage	$ 8.66
Usage charge, per 1,000 gallons	$ 2.04
Sewer Utility Service (excluding Vista Park Apartments):	
Residential Customers Flat Rate, per month	$25.62
Bulk Flat Rate, per month per customer	$24.30
Bulk Sewer Service for Vista Park Apartments:	
Bulk Flat Rate, per month per REU	$24.30

This the _18th_ day of _December, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

[1] The approved rate will enable the Company, by sound management, a reasonable opportunity to generate combined water and sewer total annual operating revenues of $727,600, which is an increase of $90,881 over present total annual operating revenues of $636,719 or a 14.3% increase.

WATER AND SEWER – CERTIFICATE

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-1044, Sub 19, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________, 2012.

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-1044, Sub 19.

Witness my hand and notarial seal, this the ____ day of ______________, 2012.

____
Notary Public

____
Address

(SEAL) My Commission Expires: ____________________________________
Date

DOCKET NO. W-1034, SUB 6

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Water Resources, Inc.,	)	RECOMMENDED ORDER GRANTING
5970 Fairview Road, Suite 710, Charlotte,	)	CERTIFICATE OF PUBLIC
North Carolina 28210, for a Certificate of	)	CONVENIENCE AND NECESSITY,
Public Convenience and Necessity for Water	)	APPROVING RATES, REQUIRING
Utility Service in River Walk Subdivision, in	)	INPROVEMENTS, AND REQUIRING
Mecklenburg County, North Carolina, and for	)	CUSTOMER NOTICE
Approval of Rates	)	

HEARD IN: Community Room, Gastonia Police Department, 200 East Long Avenue, Gastonia, North Carolina, on September 29, 2011, at 7:00 p.m.

Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on November 15, 2011, at 9:00 a.m.

BEFORE: Ronald D. Brown, Hearing Examiner

APPEARANCES:

For Water Resources, Inc.:

E. Brett Breitschwerdt, McGuireWoods, LLP, Post Office Box 27507, Raleigh, North Carolina 27601

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BROWN, HEARING EXAMINER: On January 18, 2011, Water Resources, Inc. (WRI or Company) filed with the Commission an application for a certificate of public convenience and necessity (CPCN) to provide water utility service in the River Walk Subdivision (River Walk) in Mecklenburg County, North Carolina, and further requested approval of proposed initial rates for certificated utility service to River Walk.

The Commission issued an Order Requiring Customer Notice on March 22, 2011, directing WRI to provide notice of the application to all customers in River Walk, and specifying that the matter might be decided without hearing if no significant protests were received subsequent to customer notice.

By order issued on August 12, 2011, the Commission determined that a significant number of protests had been received and scheduled a hearing for September 29, 2011, in Gastonia, North Carolina.

The Public Staff filed the affidavit of Calvin C. Craig, III, Public Utilities Financial Analyst, on September 7, 2011, and the testimony of Trisha L. Edwards, Staff Accountant, and O. Bruce Vaughan, Engineer, on September 14, 2011.

On September 8, 2011, WRI filed an amended Page 1 to its application in which it requested approval for certain customer fees not mentioned in its original application, and corrected the tap-on fee included in the original application to a connection fee of $685 per lot.

On September 27, 2011, WRI filed a Motion to Clarify Procedural Schedule, requesting that the September 29 hearing be limited to the testimony of public witnesses, that WRI be given an opportunity to file testimony, and that an evidentiary hearing be scheduled after the filing of WRI's testimony.

The matter came on for hearing as scheduled on September 29. The Hearing Examiner granted WRI's Motion to Clarify Procedural Schedule filed two days previously. The following persons testified as public witnesses: Dawn O'Connor, Sara Van Aken, Patricia Joslin, Dennis Mitchell, Roy Joslin, Lu Yan, Drew Henry, Charleen Goolsby, Baldee Thakor, Sharon Byrd, James Hough, and Jitenvra Veva.

On October 13, 2011, WRI filed copies of a Management Services Agreement and a Lease Agreement between itself and Abbott Enterprises, Inc. (AE), a corporation affiliated with WRI. On the same day WRI filed the testimony of Dennis C. Abbott, owner and president of both WRI and AE, and Patricia A. Lausier, Controller of AE.

In an Order Scheduling Hearing and Requiring Customer Notice issued on November 4, 2011, the Commission set the case for evidentiary hearing on November 15, 2011.

On November 15, 2011, prior to the evidentiary hearing, the Public Staff and WRI jointly filed an Agreement and Partial Stipulation of Settlement, accompanied by three exhibits. The stipulation reflected that the parties had reached agreement on all contested issues in the case, with one exception. The one unresolved issue was whether WRI was entitled to collect a tap-on charge or connection fee of $685 per lot from those lot owners in River Walk who have already connected to WRI's water system and have begun receiving water utility service. The parties agreed that this issue could be treated as a question of law and resolved by the Hearing Examiner on the basis of briefs and proposed orders submitted by the parties. Certain facts potentially relevant to the disputed issue were set out in Exhibit 3 attached to the parties' stipulation.

The evidentiary hearing was held on November 15 as scheduled. Pursuant to the parties' stipulation, the testimony of Public Staff witnesses Edwards and Vaughan and WRI witnesses Abbott and Lausier was admitted without objection and without cross-examination. The Hearing Examiner directed that proposed orders or briefs be filed on or before December 12, 2011.

Based upon the foregoing, the verified application, the parties' stipulation and exhibits thereto, the evidence and exhibits presented at the hearing, the proposed orders and briefs filed subsequent to the hearing, and the entire record in this proceeding, the Hearing Examiner makes the following

FINDINGS OF FACT

1. WRI is properly before the Commission seeking issuance of a CPCN pursuant to G.S. 62-110 to provide water utility service in River Walk in Mecklenburg County, North Carolina, and for approval of initial rates and charges for water utility service within River Walk.

2. As of November 2011, WRI was providing water service to 27 residences in River Walk. The residents are not being charged for these services. No other person or utility seeks to provide the utility services proposed.

3. WRI is currently also providing water service pursuant to a CPCN, and collecting rates from customers, in the Rocky River Plantation subdivision located in Cabarrus County, North Carolina. These rates were approved by order issued on December 3, 2002, in Docket No. W-1034, Sub 4, and are not at issue in this proceeding.

4. The test year for this proceeding is the 12 months ending December 31, 2010.

5. WRI has submitted all information and exhibits required for the issuance of a CPCN.

6. WRI has the technical, managerial, and financial capacity to provide water utility service in this new franchise area.

7. The quality of service being provided by WRI to current residents in River Walk is adequate. However, residents of River Walk have expressed concerns in this proceeding related to water quality, inability to communicate with WRI personnel, timing of response by WRI to leaks and service requests, and timing of response by WRI for new meter installation when requested by new residents. WRI met with the River Walk Home Owners Association Board on October 26, 2011 to discuss improving communication and responsiveness to service requests, and has agreed to undertake the recommendations of the Public Staff with regard to River Walk as set forth in Findings of Fact 8-10 below.

8. WRI has agreed to submit plans and specifications to the Department of Environment and Natural Resources (DENR), within three months after the issuance of the Commission's final order in this proceeding, documenting the conversion of Well No. 1 from gaseous chlorine to chemical feeding of hypochlorite.

9. WRI has agreed to take the following actions recommended by Public Staff witness Vaughan within six months after the issuance of the Commission's final order in this proceeding:

a. Clean and paint both tanks.
b. Eliminate the coupling leak on the ground storage tank.
c. Install vacuum breakers at each spigot at the wellhouse and wellheads.
d. Secure the cover on Well No. 2.
e. Submit the following plans to DENR:
   (1) Updated Disinfectants and Disinfection By-products (DDBP) sampling plan.
   (2) Operation and Maintenance Plan.
   (3) Emergency Response Plan.

WRI has further agreed to file a letter in this docket verifying completion of the above actions no later than 30 days after the six-month deadline.

10. WRI has agreed to take the following actions recommended by Public Staff witness Vaughan immediately upon approval of a CPCN to provide water utility service to residents within River Walk:

a. Keep a log book of customer complaints.
b. Return customer calls within 60 minutes of receipt.
c. Respond to outages within 60 minutes of receiving an outage report from a customer, even if well operations appear to be satisfactory and the reason for the reported outage is not immediately obvious.
d. Meet with the River Walk Home Owners Association within 30 days after the issuance of the Commission's final order in this docket.
e. Repair leaks in a timely manner.
f. Install meters requested by new residents in a timely manner.

11. WRI's original cost rate base as of December 31, 2010, is $16,841.

12. The $50,000 purchase price of the River Walk water system should be excluded from rate base and should not be recovered as part of the revenue requirement set forth in Finding of Fact 15 below. WRI and the Public Staff generally agree that reasonable acquisition costs of utility plant are appropriately recoverable from customers, and that a connection fee is a reasonable approach to recovering this capital cost.

13. The appropriate revenue requirement for WRI should be determined using the operating ratio method, as allowed by G.S. 62-133.1.

14. WRI should be allowed to charge initial rates that produce annual revenues of $31,025, which allows WRI the opportunity to earn a return on expenses of 8.00%. See supporting Schedules 1-3 attached to the parties' stipulation as Stipulation Exhibit 1.

15. The rates shown on Stipulation Exhibit 2 are intended to produce total annual operating revenues of $31,025 based on average consumption of 6,000 gallons per month and should be approved.

16. The charges and fees included in Stipulation Exhibit 2 should be approved.

17. WRI's existing bond in the amount of $35,000 should remain in effect. $10,000 of the existing $35,000 bond should be allocated to River Walk, and the remainder should be allocated to certificated service to Rocky River Plantation. No additional bond should be required.

18. The Management Services Agreement and Lease Agreement between WRI and AE should be accepted for filing pursuant to G.S. 62-153, and WRI should be authorized to operate under the terms of the respective agreements. Such acceptance by the Commission does not constitute approval of any amounts of rents, fees, or compensation for future ratemaking purposes and does not prejudice the right of the Public Staff and other interested parties to contest the reasonableness of the terms, charges, or fees set out in these agreements in a future proceeding.

19. The connection fee of $685 proposed by WRI should be approved with respect to customers who may connect to the River Walk system in the future. However, customers who have already connected to the system should not be required to pay this fee.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-18

These Findings of Fact are based on the stipulation filed by WRI and the Public Staff on November 15, 2011. The parties' stipulation resolved most of the disputed issues in this case. As a result of the stipulation, these facts are no longer in controversy.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The only issue on which the parties are in disagreement is the question of whether WRI's connection fee, or tap-on charge, of $685 should be applicable to all customers in River Walk Subdivision, or only to new customers who connect to the system in the future. The Public Staff contends that the connection fee should apply only to new customers; WRI asserts that it should be collected from all customers. The parties have agreed that this issue may be treated as a question of law and decided by the Hearing Examiner on the basis of the briefs and proposed orders. Stipulation Exhibit 3 provides a listing of facts potentially relevant to the disputed issue.

WRI provided the following arguments for its position:

I. There is no legal basis to justify the effective disallowance of any portion of WRI's recovery of system plant acquisition cost through a connection fee, nor any factual record evidence to support such a position.

II. The proposed connection fee is supported by all record evidence in the proceeding, and recovery of system plant acquisition cost from all customers on a pro rata basis is justified on both legal and equitable grounds.

A. There is no legal prohibition to charging one-time connection fee to a customer that is currently connected to a water system at the time a utility receives a franchise.

B. WRI is seeking recovery of its system plant acquisition cost through the stipulated connection fee at its first authorized opportunity, and there is no legal or equitable basis to impute to WRI the connection fee intended to be charged to currently connected residences.

III. Recovery of the proposed connection fee from all customers is fair to customers and WRI, and avoids discriminatory rates between similarly-situated customers.

IV. In recognition of the Public Staff's concerns, WRI proposes to allow current users to repay the connection fee over a six-month period.

WRI's argument for applying the connection fee to all customers is based primarily on its contract with the original developer of River Walk, Storer Pearson, LLC. This contract was dated November 24, 1997, and was titled "Purchase and Service Agreement for Water Utility Distribution System." It constitutes Exhibit 7 to WRI's application for a CPCN. Under the terms of this contract, Storer Pearson agreed to construct a water distribution system (including wells, water tanks, water mains, and all other needed facilities) in River Walk and to transfer ownership of the system to WRI. Sections 5 and 9 of the contract address WRI's payment of the purchase price for the water system. The purchase price is $50,000, to be paid to Storer Pearson in installments as follows: (a) an initial installment of $508; (b) an installment of $4,500 when the first customer connects to the system; (c) additional installments of $486 for each subsequent customer that connects to the system; and (d) a final installment of $10,000 when the last customer connects. Section 9 of the contract provides that WRI will seek Commission approval of a connection fee of at least $685 per lot. (With 73 lots in the subdivision, a fee of $685 per lot will be sufficient to defray the purchase price of $50,000.) If the Commission approves a fee of less than $685 per lot, the purchase price for the water system will be reduced proportionally.

Based on these contractual provisions, WRI argues that it is essential for <u>all</u> customers in River Walk – not just those who connect to the system in the future – to pay the $685 connection fee. Otherwise, the method planned by the parties for funding the purchase price of the water system will be inadequate.

In the Hearing Examiner's view, WRI relies too heavily on the provisions of its agreement with the developer, Storer Pearson. It was fully appropriate for WRI and Storer Pearson to enter into a contract that defined their rights and obligations with respect to each other; but a contract between two parties, such as WRI and Storer Pearson, cannot prejudice the rights of third parties, such as WRI's customers.

The factual circumstances of this case are very unusual. For a period of over nine years, WRI has connected customers to the water utility system in River Walk, and has provided water utility service to these customers, without charge.[1] At any time during this nine-year period, WRI could have applied for a CPCN and for authorization to charge rates to its customers, but it chose not to do so until this year. Likewise, WRI could have taken the position that until it had a CPCN and could charge rates, it would not connect customers to its system; but it chose not to proceed in this manner. By voluntarily connecting customers to its system and providing water service to them, while failing to obtain a CPCN, WRI waived its right to receive compensation for these services.

Not only has WRI waived its right to receive compensation for the services it provided without a CPCN for River Walk, it is prohibited by the rule against retroactive ratemaking from imposing any charge for these past services. The rule against retroactive ratemaking is well established in North Carolina regulatory law. In *State ex rel. Utilities Commission v. City of Durham,* 282 N.C. 308, 318, 193 S.E.2d 95, 102 (1972), the Supreme Court held that "the Commission may not fix rates retroactively so as to make them collectible for past service." Similarly, in *State ex rel. Utilities Commission v. Edmisten,* 291 N.C. 451, 468, 232 N.C. 184, 194 (1977), the Court stated: "[R]etroactive rate making occurs when an additional charge is made for past use of utility service . . . ."

During the nine years when WRI was operating without a certificate for River Walk, there was no authorized rate, either for connections to the system or for water consumption, because the Commission had no opportunity to fix rates. If the Commission were to allow WRI to impose charges on its customers now for connections that have been made in the past, it would be approving "an additional charge . . . for past use of utility service," contrary to the Supreme Court's decision in *Edmisten.* WRI has not asked the Commission for authority to charge its existing customers for their past water consumption; but if it had, that request would violate the rule against retroactive ratemaking, in exactly the same way as WRI's actual request to charge these customers for connections of service that have already occurred. In either case, the Commission would be "fix[ing] rates retroactively so as to make them collectible for past service," 282 N.C. at 318, 193 S.E.2d at 102, and this is prohibited.

Apart from considerations of waiver and retroactive ratemaking, there is still another reason why WRI should not be allowed to impose its proposed connection fee on its existing customers. WRI's contract with Storer Pearson did not specifically and unequivocally provide that WRI must charge a $685 connection fee (nor did it prohibit requesting the Commission to approve a higher connection fee). Instead, the contract recognized the authority of the Commission to fix the amount of the fee, and it provided for a reduction in the purchase price of the water system if the Commission did not approve a $685 fee. Even though 14 years have passed since the contract was executed, WRI has not paid any portion of the purchase price to Storer Pearson, except for the initial installment of $508. Thus, if the Commission rules that the

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[1] In WRI's last rate case – Docket No. W-1034, Sub 4, decided in 2002 – Public Staff witness Kenneth Rudder testified (at pages 3-4 of his prefiled testimony) that WRI was operating a water system in River Walk and serving nine customers, but it was not charging rates and planned to seek a CPCN at a later time. The Hearing Examiner found, at page 2 of his Recommended Order in that proceeding, that "[t]he Company is also operating a water utility system in River Walk Plantation in Mecklenburg County, but is not charging customers for water at that location."

connection fee cannot be collected from existing customers, it would be entirely possible for WRI and Storer Pearson to negotiate an equitable reduction in the purchase price even today.

For all these reasons, the Hearing Examiner finds and concludes that the connection fee of $685 proposed by WRI should be approved for future connections to WRI's system, but it should not be approved for those customers who have already been connected to the system.

IT IS, THEREFORE ORDERED as follows:

1. That Water Resources, Inc. is hereby granted a Certificate of Public Convenience and Necessity to provide water utility service in River Walk Subdivision in Mecklenburg County, North Carolina.

2. That Appendix A constitutes the Certificate of Public Convenience and Necessity.

3. That WRI's existing bond in the amount of $35,000 shall remain in effect.

4. That $10,000 of the existing $35,000 bond shall be allocated to River Walk, and the remainder shall be allocated to certificated service to Rocky River Plantation Subdivision.

5. That the Schedule of Rates, attached hereto as Appendix B, is hereby approved and deemed to be filed with the Commission pursuant to G.S. 62-138. Said Schedule of Rates is hereby authorized to become effective for service rendered on and after the effective date of this Order.

6. That a copy of the Notice to Customers attached hereto as Appendix C shall be mailed or hand delivered to all affected customers by WRI in conjunction with the next regularly scheduled billing process.

7. That WRI shall file the attached Certificate of Service, properly signed and notarized, within ten days of completing the requirement of the preceding paragraph.

8. That, beginning immediately, WRI shall keep a log book of customer complaints.

9. That, beginning immediately, WRI shall respond to customer calls within 60 minutes of receipt.

10. That, beginning immediately, WRI shall respond to outages within 60 minutes of receiving an outage report from a customer, even if well operations appear to be satisfactory and the reason for the reported outage is not immediately obvious.

11. That, beginning immediately, WRI shall repair leaks in a timely manner.

12. That, beginning immediately, WRI shall install meters requested by new residents in a timely manner.

13. That, within 30 days after the issuance of the Commission's final order in this docket, WRI shall meet with the River Walk Home Owners Association.

14. That, within three months after the issuance of the Commission's final order in this docket, WRI shall submit plans and specifications to the Department of Environment and Natural Resources (DENR) documenting the conversion of Well No. 1 from gaseous chlorine to chemical feeding of hypochlorite.

15. That, within six months after the issuance of the Commission's final order in this docket, WRI shall clean and paint both tanks.

16. That, within six months after the issuance of the Commission's final order in this docket, WRI shall eliminate the coupling leak on the ground storage tank.

17. That, within six months after the issuance of the Commission's final order in this docket, WRI shall install vacuum breakers at each spigot at the wellhouse and wellheads.

18. That, within six months after the issuance of the Commission's final order in this docket, WRI shall secure the cover on Well No. 2.

19. That, within six months after the issuance of the Commission's final order in this docket, WRI shall submit the following plans to DENR: (a) updated Disinfectants and Disinfection By-products (DDBP) sampling plan; (b) Operation and Maintenance Plan; and (c) Emergency Response Plan.

20. That, within seven months after the issuance of the Commission's final order in this docket, WRI shall file a report with the Commission showing that the requirements of ordering paragraphs 8 through 19 above have been met.

21. That the connection fee of $685 approved in this Order shall be applicable only to new customers connecting to the River Walk system in the future, and not to existing customers.

22. That a copy of the Order issued in this docket, including Appendix C, shall be mailed or hand delivered to all customers of WRI in River Walk Subdivision within 15 days of the date of this Order; and that WRI shall submit to the Commission the attached Certificate of Service properly signed and notarized not later than 30 days after the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of January, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX A

DOCKET NO. W-1034, SUB 6

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

WATER RESOURCES, INC.

is granted this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

to provide water utility service

in

RIVERWALK SUBDIVISION

Mecklenburg 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 27th day of January, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

APPENDIX B
PAGE 1 OF 2

SCHEDULE OF RATES

for

WATER RESOURCES, INC.

for providing water utility service in

WATER AND SEWER – CERTIFICATE

RIVER WALK SUBDIVISION

Mecklenburg County, North Carolina

Monthly Metered Water Utility Service Rates:

Base charge, zero usage	$ 38.30
Usage charge, per 1,000 gallons	$ 9.57

Connection Charge: (New Residential Connection Only)	$685.00
New Account Fee:	$ 40.00

Reconnection Charge:

If water service is cut off by utility for good cause:	$ 40.00
If water service cut off by utility at customer's request:	$ 40.00
Billing rates per hour for after hours, holidays, weekends	$ 40.00

If payment for water utility service is not received by the past-due date, a customer may, in addition to all past-due and current charges, have to pay late payment finance charges to avoid having water utility service disconnected.

To resume water utility service after discontinuance for good cause, a customer must pay the reconnection charge(s) discussed above, plus any delinquent water bill(s), including finance charges.

Returned Check Charge:	$25.00
Billing Frequency:	Shall be monthly for service in arrears
Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Finance Charges for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after the billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1034, Sub 6, on this the 27th day of January, 2012.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX C

NOTICE TO CUSTOMERS
DOCKET NO. W-1034, SUB 6
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Notice is given that the North Carolina Utilities Commission has issued an Order granting a certificate of public convenience and necessity to Water Resources, Inc. to provide water utility service in River Walk Subdivision in Mecklenburg County, North Carolina. The Commission has approved the following rates, effective for service rendered on and after the date of this Order.

Monthly Metered Water Utility Service Rates

Base charge, zero usage	$38.30
Usage charge, per 1,000 gallons	$ 9.57

The Commission ordered Water Resources, Inc., to take the following steps to improve the quality of its service: (1) Begin keeping a log book of customer complaints immediately. (2) Beginning immediately, respond to customer calls within 60 minutes of receipt. (3) Beginning immediately, respond to outages within 60 minutes after receiving an outage report from a customer, even if well operations appear to be satisfactory and the reason for the reported outage is not immediately obvious. (4) Beginning immediately, repair leaks in a timely manner. (5) Beginning immediately, install meters requested by new residents in a timely manner. (6) Within 30 days, meet with the River Walk Home Owners Association. (7) Within three months, submit plans and specifications to the Department of Environment and Natural Resources (DENR) documenting the conversion of Well No. 1 from gaseous chlorine to chemical feeding of hypochlorite. (8) Within six months, clean and paint both tanks. (9) Within six months, eliminate the coupling leak on the ground storage tank. (10) Within six months, install vacuum breakers at each spigot at the wellhouse and wellheads. (11) Within six months, secure the cover on Well No. 2. (12) Within six months, submit the following plans to DENR: (a) updated Disinfectants and Disinfection By-products (DDBP) sampling plan; (b) Operation and Maintenance Plan; and (c) Emergency Response Plan. (13) Within seven months, file a report with the Commission showing that the requirements of items (1) through (12) above have been met.

ISSUED BY ORDER OF THE COMMISSION.
This the _27th_ day of _January_, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

WATER AND SEWER – CERTIFICATE

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-1034, Sub 6, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________, 2012.

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-1034, Sub 6.

Witness my hand and notarial seal, this the ____ day of ______________, 2012.

____
Notary Public

____
Address

(SEAL) My Commission Expires: ____________________________________
Date

WATER AND SEWER – COMPLAINT

DOCKET NO. W-1160, SUB 13

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of REDUS NC COASTAL, LLC, Complainant v. KDHWWTP, LLC, Respondent	)))))))	ORDER APPROVING STIPULATION AGREEMENT

HEARD: Wednesday, May 23, 2012, at 9:30 a.m., Commission Hearing Room2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner William T. Culpepper, III, Presiding; Chairman Edward S. Finley, Jr.; and Commissioner Susan Warren Rabon

APPEARANCES:

For KDHWWTP, LLC:

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

For Bermuda Bay, LLC:

Daniel C. Higgins, Esq.
Burns, Day & Presnell, P.A.
P.O. Box 10867, Raleigh, North Carolina 27605

For TowneBank:

Karen Kemerait, Esq.
Styers and Kemerait
1101 Haynes Street, Suite 101, Raleigh, North Carolina 27604

For Group Holdings, LLC:

Dwight Allen
Brady W. Allen
The Allen Law Offices, PLLC
1514 Glenwood Avenue, Suite 200, Raleigh, North Carolina 27608

BY THE COMMISSION: On June 15, 2011, REDUS NC Coastal, LLC ("REDUS" or "Complainant"), filed a complaint with the Commission against KDHWWTP, LLC ("KDH" or "Respondent"), requesting a declaratory ruling determining rights with respect to wastewater treatment availability and capacity in KDH's wastewater treatment plant that was contracted for by Bermuda Bay, LLC ("Bermuda Bay"). On June 17, 2011, the Commission issued an Order Serving Complaint in the above-captioned proceeding.

On July 6, 2011, KDH filed its Answer and Motion to Dismiss. On July 8, 2011, the Commission issued an Order Serving Answer and Motion to Dismiss.

On July 20, 2011, REDUS filed its Reply to Answer and Motion to Dismiss.

On August 10, 2011, the Commission issued an Order Holding Docket in Abeyance.

On November 3, 2011, TowneBank ("TowneBank"), filed its Petition to Intervene, which was granted by Commission order issued November 10, 2011.

On December 12, 2011, REDUS filed its Motion to Join Necessary Party. On January 18, 2012, the Commission issued an Order Serving Motion to Join Necessary Party.

On January 20, 2012, Group Holdings, LLC ("Group Holdings") filed its Petition to Intervene, which was granted by Commission order issued January 27, 2012. On February 8, 2012, KDH filed its Response to Petition to Intervene.

On February 17, 2012, Bermuda Bay filed its request for an extension of time to file an Answer, which was granted by Commission Order issued February 22, 2012.

On February 23, 2012, Group Holdings filed its Reply to KDHWWTP's Response to Group Holdings' Petition to Intervene.

On March 2, 2012, Bermuda Bay filed its Response to REDUS NC Coastal, LLC's Motion to Join Necessary Party.

On March 9, 2012, the Commission issued an Order Joining Party and Requiring Answer.

On March 26, 2012, Bermuda Bay filed its Response to REDUS NC Coastal, LLC's Complaint and Petition for Declaratory Ruling.

On March 28, 2012, the Commission issued its Order Serving Bermuda Bay's Response to REDUS NC Coastal, LLC's Complaint and Petition for Declaratory Ruling.

On April 17, 2012, REDUS filed its request for a hearing on its Complaint and TowneBank filed its Request for Hearing.

On April 25, 2012, the Commission issued an Order Scheduling Hearing. The docket was scheduled to be heard on Wednesday, May 23, 2012, at 9;30 a.m., Commission Hearing Room 2115, Dobbs Building, 427 N. Salisbury Street, Raleigh, NC.

On May 11, 2012, Group Holdings filed a Motion for Expedited Relief requesting Commission approval of a Stipulation of Partial Settlement that had been entered into by Group Holdings, Bermuda Bay, REDUS, and TowneBank.

On May 15, 2012, TowneBank filed attachments to its November 2, 2011, Petition to Intervene.

On May 23, 2012, the Commission did not conduct an evidentiary hearing as initially scheduled. Instead, the Commission inquired from REDUS, KDHWWTP, TowneBank, Group Holdings, and Bermuda Bay (collectively "the Parties") as to the terms of a Settlement that had been reached by the Parties, but which had then not been reduced to writing. At the conclusion of the Commission's inquiry, the Parties were ordered to file a written Settlement Agreement and a Proposed Order or Orders for the Commission to consider.

On July 25, 2012, the Parties filed an Agreement and Stipulation of Settlement ("Stipulation") and the Joint Proposed Order of the Stipulating Parties.

Based on the foregoing, the pleadings, the exhibits presented at the hearing, the Stipulation, and the entire record in this proceeding, the Commission makes the following

FINDINGS OF FACT

1. KDH is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of this Commission. KDH is engaged in the business of providing sewer utility service to retail customers in eastern North Carolina. KDH's office and principal place of business are in North Carolina.

2. The Commission has jurisdiction over the rates and charges, rate schedules, classifications, and practices of public utilities operating in North Carolina, including KDH, under Chapter 62 of the General Statutes of North Carolina.

3. KDH is lawfully before the Commission based upon REDUS's complaint, G.S. §62-60 and Commission Rule R1-9.

4. Bermuda Bay was the initial developer of the Bermuda Bay residential real estate development ("Bermuda Bay Development") located in Dare County, North Carolina.

5. In 2004, Bermuda Bay sought financing from Wachovia Bank, N.A., now known as Wells Fargo Bank, N.A. ("Wells Fargo"), for the Bermuda Bay Development. On July 23, 2004, Bermuda Bay executed two promissory notes in favor of Wells Fargo. Both promissory notes were secured by a deed of trust covering the Bermuda Bay Development. Bermuda Bay and Wells Fargo subsequently modified the promissory notes and deed of trust.

6. In 2006, VOC, a real estate developer, purchased Units 2, 3, 4, 5, and 6 of the Hamilton Cay condominium development ("Hamilton Cay") in the Bermuda Bay Development from Bermuda Bay. TowneBank provided financing to VOC for the purchase of that real estate, and VOC executed a promissory note in favor of TowneBank secured by a deed of trust, in which VOC granted to TowneBank the rights, title and interest to Units 2, 3, 4, 5, and 6 of Hamilton Cay. After receiving partial payment from VOC, TowneBank released Units 5 and 6 from the deed of trust, but retained the rights, title and interest in Units 2, 3, and 4 in Hamilton Cay.

7. On January 30, 2008, TowneBank provided lending to Bermuda Bay for the Devonshire Place area in Bermuda Bay ("Devonshire"), and TowneBank obtained a deed of trust to Devonshire, whereby Bermuda Bay granted to TowneBank the rights, title and interest to lots located in Devonshire. TowneBank and Community Bankers' Bank ("CBB") executed a Master Loan Participation Agreement, in which TowneBank sold to CBB a Master Participation in TowneBank's loan to Bermuda Bay. Therefore, CBB is the beneficial holder of a first mortgage and lien on Devonshire. The Master Loan Participation Agreement provides TowneBank with the sole right to enforce the obligations of Bermuda Bay.

8. The deed of trust, as modified in favor of Wells Fargo, covers 71.9% of the Bermuda Bay Development. The remaining 28.1% of the Bermuda Bay Development is covered by a deed of trust in favor of TowneBank.

9. On July 23, 2004, Bermuda Bay entered into an Agreement for Sewer Utility Service with KDH ("Agreement"), whereby KDH agreed to provide 118,400 gallons per day ("gpd") of sewage treatment capacity in its treatment plant to Bermuda Bay at KDH's capacity charge approved by the Commission.

10. On January 30, 2006, KDH acknowledged by letter its willingness to serve and allocate capacity (out of the 118,400 gpd when paid for) to certain properties in the Bermuda Bay Development, including Building 308 at 308 Cambridge Road, Kill Devil Hills, North Carolina 27948 ("Building 308").

11. The Agreement was amended and restated by Bermuda Bay and KDH in an Amended and Restated Agreement for Sewer Utility Service dated June 16, 2006 ("Amended Agreement") to reduce the amount of capacity to be purchased by Bermuda Bay to serve the Bermuda Bay Development to 114,170 gpd of capacity. Bermuda Bay paid KDH, either by direct payment or by virtue of credits/reimbursements due Bermuda Bay from KDH for Bermuda Bay's installation of irrigation infrastructure used by KDH, for wastewater treatment capacity of at least 66,965.33 gpd, of which 31,500 gpd was allocated to Bermuda Bay by KDH based on certificates of occupancy, leaving paid for but unallocated capacity owned by Bermuda Bay of 35,465.33 gpd.

12. Bermuda Bay defaulted on the modified promissory notes due to Wells Fargo by failing to make required payments of principal and interest as they became due.

13. As a result of this default, Wells Fargo instituted foreclosure action pursuant to the powers of sale contained in the relevant deed of trust. Bermuda Bay filed a Petition in the U.S. Bankruptcy Court for the Eastern District of Virginia, which is where it was incorporated. Eventually, that Court lifted the automatic stay and the foreclosure was allowed to proceed.

14. Wells Fargo purchased the property covered by its deed of trust at foreclosure and transferred it to REDUS (an affiliate of Wells Fargo).

15. VOC defaulted on the promissory note in favor of TowneBank for Units 2, 3, and 4 of Hamilton Cay, and TowneBank foreclosed on Units 2, 3, and 4 of Hamilton Cay.

16. Bermuda Bay defaulted on the January 30, 2008 promissory note that is secured by a deed of trust on the Devonshire property in favor of TowneBank. TowneBank has instituted foreclosure proceedings as to the Devonshire property, but that foreclosure has not yet been completed. In the promissory note and deed of trust, Bermuda Bay assigned its right, title and interest in all present and future leases and rents in Devonshire to TowneBank. Bermuda Bay stipulates that TowneBank is entitled to the paid-for capacity that is allocated to the Devonshire property, as provided for in this Agreement.

17. On June 15, 2011, REDUS filed a formal complaint against KDH petitioning the Commission for a ruling determining the parties' rights with respect to treatment availability and capacity in KDH's wastewater treatment plant.

18. REDUS subsequently sold a segment of the foreclosed property, identified as Building 308, to Group Holdings.

19. In order to begin timely construction, Group Holdings contacted KDH to acquire the sewer capacity needed in order to obtain required building permits. Due to the existence of this Docket, KDH declined to provide any of the sewer capacity previously purchased by Bermuda Bay to Group Holdings.

20. In December 2011, Group Holdings separately purchased, in its own name, the capacity it needed in order to meet its required construction schedule for $31,152.00. This payment was made to KDH with the understanding that the amount tendered for this purchase would be refunded by KDH if the Commission determined that Group Holdings was entitled to have its capacity needs met from the capacity previously purchased by Bermuda Bay but not yet allocated.

21. On March 21, 2012, TowneBank, through its subsidiary Northeastern North Carolina Properties at Bermuda Bay, LLC, entered into a Purchase and Sale Agreement with KDH, in which TowneBank purchased 10,800 gpd of sewer capacity for the amount of $140,184.00. In the event that the Commission in this Docket allocates or assigns any paid-for capacity to TowneBank, the Purchase and Sale Agreement provides that any payment for capacity made by TowneBank, through its subsidiary Northeastern North Carolina Properties at Bermuda Bay, LLC, will be applied to any outstanding balance with TowneBank, credited to

TowneBank's account, or refunded to TowneBank. TowneBank has provided the full amount of the purchase price, $140,184.00, to KDH.

22. On June 20, 2012, TowneBank, through its subsidiary Northeastern North Carolina Properties Bermuda Bay Development, LLC, entered into a second Purchase and Sale Agreement with KDH, in which TowneBank agreed to purchase 12,000 gpd of sewer capacity for Devonshire for the amount of $155,760.00. TowneBank/CBB have provided payment of $77,880 to KDH under this Purchase and Sale Agreement. This Purchase and Sale Agreement provides that in the event that the Commission allocates or assigns any paid-for capacity to TowneBank, the payment made by TowneBank pursuant to this Purchase and Sale Agreement will be applied to any outstanding balance, credited to the account, or refunded to TowneBank.

23. On May 22, 2012, the Parties reached a comprehensive settlement resolving all matters in dispute in this docket.

24. On July 25, 2012, the Parties filed the Stipulation with the Commission.

25. The Stipulation provides that Bermuda Bay has paid to and received credits from KDH for wastewater treatment capacity for the Bermuda Bay Development in the amount of $869,210.03, which is equivalent to 66,965.33 gpd of capacity.

26. The Parties agree and stipulate that the amount of capacity that has been allocated to the Bermuda Bay Development is 31,500 gpd. Therefore, the remaining unallocated, paid-for capacity owed by KDH to serve the Bermuda Bay Development is 35,465.33 gpd.

27. The Stipulation provides that the Parties agree that REDUS is entitled to 71.9% of the remaining 35,465.33 gpd of capacity, minus the 2,400 gpd Group Holdings is entitled to as a result of purchasing Building 308 from REDUS. The Parties further agree that TowneBank is entitled to 28.1% of the remaining 35,465.33 gpd of capacity. Accordingly, the Parties agree as follows regarding the allocation of the 35,465.33 gpd of capacity:

(a) REDUS is entitled to 23,100 gpd;
(b) Group Holdings is entitled to 2,400 gpd; and
(c) TowneBank is entitled to 9,965 gpd.

28. The Parties agree that KDH shall refund to Group Holdings the $31,152.00 payment for sewage capacity made by Group Holdings to KDH in December 2011.

29. The Parties also agree that KDH shall provide a refund in the amount of $61,269.02 to TowneBank and provide credit in the amount of $68,076.68 due under the June 20, 2012 Purchase and Sale Agreement. Therefore, the amount of $9,803.32 is due to KDH under the terms of the June 20, 2012 Purchase and Sale Agreement.

30. In the event that TowneBank/CBB require capacity in excess of the amounts purchased in the March 21, 2012 Purchase and Sale Agreement and the June 20, 2012 Purchase and Sale Agreement, TowneBank/CBB will be required to purchase any such excess capacity from KDH.

31. REDUS agrees that all of the capacity which it receives as a result of the Stipulation will be used only in the geographical area represented by the properties in the Bermuda Bay Development which REDUS acquired from Wells Fargo. REDUS acknowledges that if REDUS (or its successor) further develops the portion of the Bermuda Bay Development currently owned by REDUS, the 23,100 gpd which REDUS agrees to accept in the Stipulation may not be sufficient to serve all of the resulting sewer capacity needs. Therefore, at some point in time, either REDUS (or its successor) may be required to acquire additional capacity from KDH. However, KDH is not required to retain any amount of capacity for REDUS (or its successor).

32. The Parties further agree that both the Agreement and Amended Agreement for sewer capacity by and between Bermuda Bay and KDH are terminated, and that no Party retains any claims against any other Party based on the Agreement and Amended Agreement.

33. The provisions of the Stipulation are just and reasonable to all of the Parties under the circumstances of this proceeding and should be approved in their entirety.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 1-3

The evidence supporting these findings and conclusions is contained in the pleadings, the exhibits received into evidence at the hearing, the Stipulation and the entire record in this proceeding. These findings and conclusions are informational, procedural, and jurisdictional in nature, and are not contested by any party.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 4-33

The evidence supporting these findings and conclusions is contained in the pleadings, the exhibits received into evidence at the hearing, the Stipulation and the entire record in this proceeding. These findings and conclusions are not contested by any party.

Bermuda Bay was the initial developer of the Bermuda Bay Development. In 2004, Bermuda Bay sought financing from Wells Fargo for the Bermuda Bay Development. On July 23, 2004, Bermuda Bay executed two promissory notes in favor of Wells Fargo. Both promissory notes were secured by a deed of trust covering the Bermuda Bay Development. Bermuda Bay and Wells Fargo subsequently modified the promissory notes and deed of trust. The deed of trust in favor of Wells Fargo, as modified, covers 71.9% of the Bermuda Bay Development. The remaining 28.1% of the Bermuda Bay Development is covered by a deed of trust in favor of TowneBank.

In 2006, VOC, a real estate developer, purchased Units 2, 3, 4, 5, and 6 of Hamilton Cay in the Bermuda Bay Development from Bermuda Bay. TowneBank provided financing to VOC for the purchase of that real estate, and VOC executed a promissory note in favor of TowneBank secured by a deed of trust, in which VOC granted to TowneBank the rights, title and interest to Units 2, 3, 4, 5, and 6 of Hamilton Cay. After receiving partial payment from VOC, TowneBank released Units 5 and 6 from the deed of trust, but retained the rights, title and interest in Units 2, 3, and 4 in Hamilton Cay.

On January 30, 2008, TowneBank provided lending to Bermuda Bay for Devonshire, and TowneBank obtained a deed of trust to Devonshire, whereby Bermuda Bay granted to TowneBank the rights, title and interest to lots located in Devonshire. TowneBank and CBB executed a Master Loan Participation Agreement, in which TowneBank sold to CBB a Master Participation in TowneBank's loan to Bermuda Bay. Therefore, CBB is the beneficial holder of a first mortgage and lien on Devonshire. The Master Loan Participation Agreement provides TowneBank with the sole right to enforce the obligations of Bermuda Bay.

On July 23, 2004, Bermuda Bay entered into the Agreement, whereby KDH agreed to provide 118,400 gpd of sewage treatment capacity in its treatment plant to Bermuda Bay at KDH's capacity charge approved by the Commission. On January 30, 2006, KDH acknowledged by letter its willingness to serve and allocate capacity to certain properties in Bermuda Bay, including Building 308. The Agreement was amended and restated by Bermuda Bay and KDH in the Amended Agreement dated June 16, 2006 to reduce the amount of capacity to be purchased by Bermuda Bay to serve the Bermuda Bay Development to 114,170 gpd of capacity.

Bermuda Bay defaulted on the modified promissory notes due to Wells Fargo by failing to make required payments of principal and interest as they became due. As a result of this default, Wells Fargo instituted foreclosure action pursuant to the powers of sale contained in the relevant deed of trust. Bermuda Bay filed a Petition in the Bankruptcy Court in Virginia, where it was incorporated. Eventually, the Court lifted the automatic stay and the foreclosure was allowed to proceed. Wells Fargo purchased the property at foreclosure and transferred it to REDUS.

REDUS subsequently sold a segment of the foreclosed property, identified as Building 308, to Group Holdings. In order to begin timely construction, Group Holdings contacted KDH to acquire the sewer capacity needed in order to obtain required building permits. Due to the existence of this docket, KDH declined to provide any of the sewer capacity previously purchased by Bermuda Bay to Group Holdings.

In December 2011, Group Holdings separately purchased, in its own name, the capacity it needed in order to meet its required construction schedule for $31,152.00. This payment was made with the understanding that the amount tendered for this purchase would be refunded by KDH if the Commission determined that Group Holdings was entitled to have its capacity needs met from the capacity previously purchased by Bermuda Bay but not yet allocated.

On March 21, 2012, TowneBank, through its subsidiary Northeastern North Carolina Properties at Bermuda Bay, LLC, entered into a Purchase and Sale Agreement with KDH, in which TowneBank purchased 10,800 gpd of sewer capacity for the amount of $140,184.00. The Purchase and Sale Agreement provides that, in the event that the Commission in this Docket allocates or assigns any paid-for capacity to TowneBank, any payment for capacity made by TowneBank, through its subsidiary Northeastern North Carolina Properties at Bermuda Bay, LLC, will be applied to any outstanding balance with TowneBank, credited to TowneBank's account, or refunded to TowneBank. TowneBank has provided the full amount of the purchase price, $140,184.00, to KDH.

On May 22, 2012, the Parties reached a comprehensive settlement resolving all matters in dispute in this Docket.

On June 20, 2012, TowneBank, through its subsidiary Northeastern North Carolina Properties Bermuda Bay Development, LLC, entered into a second Purchase and Sale Agreement with KDH, in which TowneBank agreed to purchase 12,000 gpd of sewer capacity for Devonshire for the amount of $155,760.00. TowneBank/CBB have provided payment of $77,880 to KDH under this Purchase and Sale Agreement. This Purchase and Sale Agreement provides that in the event that the Commission allocates or assigns any paid-for capacity to TowneBank, the payment made by TowneBank pursuant to this Purchase and Sale Agreement will be applied to any outstanding balance, credited to the account, or refunded to TowneBank.

On July 25, 2012, the Parties filed the Stipulation with the Commission. The Stipulation provides that Bermuda Bay has paid to and received credits from KDH for capacity for the Bermuda Bay development in the amount of $869,210.03, which is equivalent to 66,965.33 gpd of capacity.[1]

The Stipulation provides that the amount of capacity that has been allocated to the Bermuda Bay development is 31,500 gpd. At the hearing, counsel for the Parties confirmed that there was no dispute that 31,500 gpd was the correct figure for the amount for the paid-for capacity that has already been allocated to the Bermuda Bay Development.

Therefore, the remaining unallocated, paid-for capacity owed by KDH to Bermuda Bay is 35,465.33 gpd.

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[1] This number was arrived at as follows (*see* Official Exhibits to the Hearing Transcript):

In the Second Amended Plan of Reorganization of Bermuda Bay, LLC and ABKDH, LLC issued February 19, 2010 (Compl., Ex. D), the recitals to the agreement between KDHWWTP and the debtors provide that the principal sum remaining unpaid from the scheduled 2007 and 2008 annual payments due to KDHWWTP under the Amended Agreement is $612,716.58, which is equivalent to 47,204.66 gallons per day at KDHWWTP's rate of $12.98/gallons per day. That means that Bermuda Bay paid for 66,965.33 gallons per day (114,170 minus 47,204.66), which at $12.98/gallons per day equals payments/credits in the amount of $869,210.03.

$612,716.58 / $12.98/gpd = 47,204.66 gpd that have not yet been paid for

114,170 gpd (contract amount) - 47,204.66 gpd (not paid for) = 66,965.33 gpd (paid for)

The Stipulation provides that the Parties agree that REDUS is entitled to 71.9% of the remaining 35,465.33 gpd of capacity (which equals approximately 25,500 gpd), minus the 2,400 gpd Group Holdings is entitled to as a result of purchasing Building 308 from REDUS (leaving REDUS with an entitlement to 23,100 gpd). The Parties further agree that TowneBank is entitled to the 28.1% of the remaining 35,465.33 gpd of capacity, which equals 9,965 gpd.

The Parties agree that KDH shall refund to Group Holdings the $31,152.00 payment for sewage capacity made by Group Holdings to KDH in December 2011.

The Parties agree that KDH shall provide a refund in the amount of $61,269.02 to TowneBank and provide credit in the amount of $68,076.68 due under the June 20, 2012 Purchase and Sale Agreement. The amount of $9,803.32 continues to be due from TowneBank to KDH under the terms of the June 20, 2012 Purchase and Sale Agreement.

The Stipulation also provides that in the event that TowneBank/CBB require capacity in excess of the amounts purchased in the March 21, 2012 Purchase and Sale Agreement and the June 20, 2012 Purchase and Sale Agreement, TowneBank/CBB will be required to purchase any such excess capacity from KDH. Similarly, REDUS acknowledges that if REDUS (or its successor) further develops the portion of the Bermuda Bay Development currently owned by REDUS, the 23,100 gpd which REDUS agrees to accept in this Stipulation may not be sufficient to serve all of the resulting sewer capacity needs. Therefore, at some point in time, either REDUS (or its successor) may be required to acquire additional capacity from KDH. However, KDH is not required to retain any amount of capacity for REDUS (or its successor). Additionally, the Stipulation provides that REDUS agrees that all of the capacity which it receives as a result of this Stipulation will be used only in the geographical area represented by the properties in the Bermuda Bay Development which REDUS acquired from Wells Fargo.

The Parties agree that both the Agreement and Amended Agreement for sewer capacity by and between Bermuda Bay and KDH are terminated, and that no Party retains any claims against any other Party based on the Agreement and Amended Agreement.

No parties are making any claims as to the capacity which Bermuda Bay contracted for in the Amended Agreement, but never paid for; specifically, TowneBank and REDUS have abandoned any such claims to unpaid-for capacity made in their initial pleadings. The unpaid-for capacity belongs to KDH, which is free to sell such capacity as it sees fit.

The Commission, having carefully reviewed the Stipulation and all of the evidence of record, finds and concludes that the provisions of the Stipulation are just and reasonable to all the Parties under the circumstances of this proceeding and should be approved in their entirety.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by REDUS, TowneBank, Bermuda Bay, KDH, and Group Holdings is hereby approved in its entirety;

2. That REDUS shall be entitled to 23,100 gpd of treatment availability and capacity in KDH's wastewater treatment plant;

3. That Group Holdings shall be entitled to 2,400 gpd of treatment availability and capacity in KDH's wastewater treatment plant;

4. That TowneBank shall be entitled to 9,965 gpd of treatment availability and capacity in KDH's wastewater treatment plant;

5. That KDH shall refund to Group Holdings the $31,152.00 payment for sewage capacity made by Group Holdings to KDH in December 2011;

6. That KDH shall provide a refund in the amount of $61,269.02 to TowneBank and provide credit in the amount of $68,076.68 due under the June 20, 2012 Purchase and Sale Agreement. The amount of $9,803.32 continues to be due from TowneBank to KDH under the terms of the June 20, 2012 Purchase and Sale Agreement; and

7. That both the Agreement and Amended Agreement for sewer capacity by and between Bermuda Bay and KDH are terminated, and that no Party retains any claims against any other Party based on the Agreement and/or the Amended Agreement.

ISSUED BY ORDER OF THE COMMISSION.
This the 16th day of August, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Cf081612.01

WATER AND SEWER – DISCONTINUANCE

DOCKET NO. W-386, SUB 18

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Holiday Island Property Owners Association, Inc., d/b/a Holiday Island Utility Company, 123 B Clubhouse Road, Hertford, North Carolina 27944, to Discontinue Water and Sewer Utility Services at Camp Holiday, Perquimans County, North Carolina	))))))	ORDER APPROVING EMERGENCY ASSESSMENT AND TEMPORARY SURCHARGE

HEARD IN: Perquimans County Courthouse, Courtroom 1, 128 N. Church Street, Hertford, North Carolina, on Thursday, December 15, 2011, at 9:00 a.m.

Perquimans County Courthouse, Courtroom 1, 128 N. Church Street, Hertford, North Carolina, on Tuesday, January 31, 2012, at 10:00 a.m.

BEFORE: Commissioner William T. Culpepper, III, Presiding; and Commissioners Bryan E. Beatty and ToNola D. Brown-Bland

APPEARANCES:

For Holiday Island Property Owners Association, Inc., d/b/a Holiday Island Utility Company:

Steven J. Levitas, Kilpatrick, Townsend & Stockton, LLP, 4208 Six Forks Road, Suite 1400,Raleigh, North Carolina 27609

For Minzies Creek Village:

Lloyd C. (Clif) Smith, III, Pritchett & Burch, PLLC, Post Office Drawer 100, Windsor, North Carolina 27983

For the Using and Consuming Public:

William E. Grantmyre, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On September 6, 2011, Holiday Island Property Owners Association, Inc., d/b/a Holiday Island Utility Company (HIPOA), filed an Application to Discontinue Water and Sewer Utility Services (Discontinuance Application) to the Camp Holiday service area located in Perquimans County, North Carolina, stating therein that there is no reasonable probability that HIPOA will be able to realize sufficient revenues from its customers to make the repairs and improvements to HIPOA's sewer system which are required by the North Carolina Department of Environment and Natural Resources (NCDENR).

On October 3, 2011, the Commission issued an Order Scheduling Hearing and Requiring Public Notice for the Discontinuance Application. That Order scheduled a public hearing for December 15, 2011, in the Perquimans County Courthouse in Hertford, North Carolina.

On November 2, 2011, HIPOA prefiled the direct testimony and exhibits of its witnesses Elaine A. Mazure, HIPOA's Treasurer; David May, Aquifer Protection Regional Supervisor for the Washington Region of the Division of Water Quality; and William G. Simmons, Professional Engineer.

On November 16, 2011, the Public Staff-North Carolina Utilities Commission (the Public Staff) prefiled the direct testimony of Babette McKemie, Utilities Engineer, Water and Sewer Division; the direct testimony and exhibits of Laura D. Bradley, Staff Accountant, Accounting Division; and the Affidavit of Calvin C. Craig, III, Financial Analyst, Economic Research Division. Intervention and participation in this docket by the Public Staff is made and recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On November 16, 2011, customers of HIPOA's sewer system (an unincorporated nonprofit association named Minzies Creek Village), filed a Petition to Intervene. The Commission granted the Minzies Creek Village Petition to Intervene by Order dated November 22, 2011.

On December 2, 2011, HIPOA prefiled the rebuttal testimony and exhibits of its witness, Elaine A. Mazur.

On December 8, 2011, HIPOA filed a Motion to Stay Proceeding in which HIPOA requested the Commission stay until June 15, 2012, the discontinuance of water and sewer utility service aspects of this proceeding in order to provide Minzies Creek Village the opportunity to form a sanitary district for the purpose of taking ownership of the HIPOA water and sewer utility systems.

Also, on December 8, 2011, HIPOA filed a Petition for Emergency Assessment and Temporary Surcharge (Petition).

Pursuant to the Petition, HIPOA applied for an emergency assessment totaling $6,917 and a temporary surcharge totaling $8,100. HIPOA stated the emergency assessment is necessary to pay for past improvements and renovation costs to its sewer utility system. HIPOA stated the temporary surcharge is necessary to generate funds to continue operating the system and create a reserve for maintenance and repair costs that might arise during the pendency of this proceeding. HIPOA proposed that each of its 90 customers should be assessed $25.62 per month and surcharged $30.00 per month for three months, with payments due 30 days from each monthly billing. HIPOA also requested Commission approval to disconnect utility service to any customers unable or unwilling to pay the assessment and/or surcharge.

On December 8, 2011, the Public Staff filed Comments supporting the requested stay of the discontinuance proceeding and supporting the requested emergency assessment and temporary surcharge.

On December 12, 2011, Minzies Creek Village filed a Consent to Motion to Stay Proceeding citing its efforts to form a sanitary district.

On December 12, 2011, the Commission issued an Order Staying Evidentiary Hearing and Imposing Conditions. Said Order stayed the discontinuance evidentiary hearing until June 15, 2012, and required Minzies Creek Village to file progress reports with the Commission regarding the progress of the sanitary district formation.

On December 15, 2011, the first public hearing was held in Hertford, North Carolina, as scheduled. The following customers presented testimony: William Smith, Annie Gavin, Norman Morris, Jr., Peter Messina, Jr., Jeannie Thigpen, Jeanne Hecker, Frank Page, Melinda Sue Haugen, Clay Helm, David Stephenson, Jerry Butler, Christopher Colvin, James Finley, Chris Angelo, Richard Keller, and David Colvin. The public witnesses generally testified that they were opposed to closure of the wastewater treatment plant and supported the creation of a sanitary district.

On December 22, 2011, the Commission issued its Order Scheduling Public Hearing, which among other things, scheduled an evidentiary hearing on the Petition for January 31, 2012, in Hertford, North Carolina.

On January 20, 2012, the Public Staff filed the Assessment and Surcharge Testimony of its witness, Laura D. Bradley, Accountant, Public Staff Accounting Division.

On January 26, 2012, HIPOA filed the testimony and exhibits of its Secretary Barbara Bostwick.

On January 31, 2012, the second public hearing was held in Hertford, North Carolina, as scheduled. The following customers presented testimony: Cheryl Booten, Marshall Whisner, Kim Loveland, Jo Ann Kehr, Jeanne Hecker, Sheila Robertson, Melinda Haugen, and Clay Helm. The public witnesses generally testified that they were opposed to closure of the wastewater treatment plant, supported the creation of a sanitary district, and were concerned about accountability for funds paid to HIPOA. HIPOA presented the testimony of witness Barbara Bostwick. The Public Staff presented the testimony of witness Laura Bradley.

On March 2, 2012, the Public Staff and HIPOA filed a Joint Proposed Order. On March 23, 2012, the Commission issued an Order Notifying Parties of Ex Parte Communication.

Based upon the Petition, the testimony presented at the December 15, 2011, hearing and the January 31, 2012, public hearings, the Joint Proposed Order, and other evidence of record, the Commission makes the following

FINDINGS OF FACT

1. HIPOA has a certificate of public convenience and necessity to provide water and sewer utility service to customers in the Camp Holiday service area located in Perquimans County, North Carolina.

2. Minzies Creek Village is an unincorporated nonprofit association comprised of customers of HIPOA residing in the Camp Holiday water and sewer service area. Minzies Creek Village's duly authorized representative is attorney Lloyd C. Smith, III. Only attorney Smith is authorized to communicate the position of Minzies Creek Village to this Commission.

3. During the summer of 2011, HIPOA incurred costs for sewer plant improvement renovations associated with a sewer leak. The costs totaled $6,917, as shown on Exhibit A of the December 8, 2011, Petition.

4. On January 31, 2012, HIPOA provided water utility service to 87 residential customers and sewer utility service to 83 residential customers.

5. By Order dated June 12, 1992, in Docket No. W-386, Sub 8, the Commission approved for HIPOA an emergency assessment of $580 per lot for each of approximately 450 lots in the Camp Holiday water and sewer service area (sections H, P, and R). The Commission Order required HIPOA to keep the revenues produced by this assessment in a separate fund, and the revenues were ordered to be used solely for upgrading the sewer plant to bring it into compliance with North Carolina law and the regulations of the Division of Environmental Management (DEM), which is the predecessor agency to the Division of Water Quality (DWQ) of the NCDENR. This separate fund has been named the Emergency Capital Improvement Assessment (ECIA) account.

6. Approximately one third of the $580 per lot emergency assessment approved in 1992 has not been collected. As of December 31, 2011, the ECIA account had a balance of $293.

7. The Public Staff has reviewed the ECIA bank statements for the past nine years and there are receipts for all expenditures. Public Staff witness Bradley testified that she has observed nothing improper from her review.

8. The Public Staff recommended that the Commission approve an emergency assessment for sewer utility customers only, totaling $6,917, for the sewer system improvement renovations made in 2011, thereby enabling HIPOA to repay the $6,917 loan that the Holiday Island Property Owners Association, Inc. (Homeowners Association) made to HIPOA to pay for needed sewer plant improvements.

9. The Petition requested the Commission approve a $6,917 emergency assessment based upon 90 sewer customers being assessed $25.62 per month for three months. The Petition also requested the Commission approve a $8,100 temporary surcharge based upon 90 sewer customers being charged $30.00 per month for three months. The total combined emergency assessment and temporary surcharge per customer after three months (based on 90 customers) would be $166.86.

10. At the January 31, 2012, public hearing, HIPOA revised its requests based upon the reduced number of 83 sewer customers. HIPOA requested the total emergency assessment and temporary surcharge per customer remain at $166.86 with the applied for emergency

assessment adjusted to $27.78 (initial request was $25.62) per customer per month for three months and the applied for temporary surcharge reduced to $27.84 (initial request was $30.00) per customer per month for three months. The HIPOA revisions would result in the total emergency assessment remaining at $6,917, and the total temporary surcharge being reduced to $6,932.

11. The sewer operating expenses during 2011, exclusive of the $6,917 borrowed for sewer plant improvements, are not out of line compared to the HIPOA sewer operating expenses audited by the Public Staff in Docket No. W-386, Sub 15, which was HIPOA's last rate case proceeding, and was based upon a test period of 12 months ended December 31, 2004.

12. The HIPOA sewer revenues roughly equal the operating expenses, but do not provide adequate funds to create a reserve for maintenance and repair costs that may arise during the pendency of this proceeding.

13. The Public Staff recommended the Commission approve the revised temporary surcharge totaling $6,932, to enable HIPOA to continue to provide water and sewer service, including making necessary improvements, repairs, and replacements to maintain adequate sewer utility service.

14. DWQ Regional Supervisor David May informed the Public Staff that DWQ supported the temporary surcharge as the funds were necessary to continue operating the sewer system, especially for repairs. Mr. May further informed the Public Staff that on the January 31, 2012, hearing date at least one or two pumps were out at the sewer plant that need repair, and there is no money to make the repairs.

15. It is appropriate for there to be accounting and monthly reporting requirements for funds collected for the emergency assessment and temporary surcharge. It is appropriate for the emergency assessment funds collected to be placed into the current ECIA account for the loan repayment, and the temporary surcharge funds collected be maintained in a separate account, so that the balance of each of these funds can be transferred with the systems to the sanitary district, upon the successful completion and formation of the sanitary district and Commission approval.

16. It is appropriate for the Public Staff to review the documentation for the expenditures utilizing the temporary surcharge funds.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 AND 2

The evidence supporting these findings of fact is contained in HIPOA's Petition, the Minzies Creek Village Petition to Intervene, and the Commission's records. These findings are primarily jurisdictional and informational and are uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence supporting this finding is found in the Exhibit A of the Petition, the testimony of HIPOA witness Barbara Bostwick and the testimony of Public Staff Accountant Laura Bradley.

HIPOA witness Bostwick testified that the $6,917 detailed on Petition Exhibit A was for improvement renovations made to the sewer system during the summer of 2011. Public Staff witness Bradley testified that HIPOA incurred the $6,917 costs as shown on Petition Exhibit A, for plant improvements associated with a sewer leak over the 2011 summer months. Witness Bradley testified that since HIPOA was unable to cover the cost of these sewer plant improvements, which were necessary to get the sewer system up and running again, the Homeowners Association loaned HIPOA the funds.

The Commission concludes that during the summer of 2011, HIPOA incurred $6,917 in costs for sewer plant improvement renovations associated with a sewer leak.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence supporting this finding is contained in the testimony of HIPOA witness Barbara Bostwick.

HIPOA witness Bostwick testified that at the time of filing the Petition on December 8, 2011, there were 90 customers. She testified that on the January 31, 2012, hearing date, there were a total of 87 water customers and 83 sewer customers, as four water customers do not receive sewer service.

No other witnesses presented evidence of the number of water or sewer utility customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 AND 6

The Commission takes judicial notice of the Commission's Order dated June 12, 1992, in Docket No. W-386, Sub 8, approving an emergency assessment of $580 for each lot owner in the Camp Holiday water and sewer service area (sections H, P, and R).

Public Staff witness Bradley testified that the Commission's June 12, 1992, Order approved the emergency assessment to make capital improvements required by DEM in order to achieve compliance. Witness Bradley testified that this assessment was $580 per camp lot. She testified that approximately one third of the lot owners have not paid these $580 per lot assessments. Witness Bradley further testified that over the years the ECIA collected assessments have been spent for capital improvements and major repairs.

Public Staff witness Bradley testified that she has reviewed the ECIA bank statement and agrees with HIPOA witness Bostwick that the ECIA account balance on December 31, 2011, was $293.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

In response to questions from the Commission, Public Staff witness Bradley testified that she has reviewed the ECIA bank statements for the past nine years and that there are receipts for all expenditures. Further, witness Bradley testified that she has observed nothing improper from her review.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

Public Staff witness Bradley testified that the Public Staff recommends the Commission approve an emergency assessment totaling $6,917, as HIPOA needs to repay the outstanding debt of $6,917 for the 2011 sewer plant improvement renovations outlined in Petition Exhibit A.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is found in the December 8, 2011, Petition (Paragraph 18) and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

At the January 31, 2012, public hearing, HIPOA witness Bostwick amended her written testimony filed on January 26, 2012, as a result of the decrease in the number of sewer customers to 83.

Witness Bostwick testified that HIPOA did not desire to modify the three month total combined emergency assessment and temporary surcharge per customer of $166.86. She testified that HIPOA requested the $6,917 total applied for emergency assessment remain the same with the monthly per sewer customer assessment increased from $25.62 to $27.78. The total emergency assessments would be $27.78 per customer X 83 customers X 3 months = $6,917.

Witness Bostwick testified that, in order for the total combined emergency assessment and temporary surcharge of three monthly payments per sewer customer to remain at $166.86, as stated in the filed Petition, HIPOA requested that the monthly temporary surcharge per sewer customer be reduced from $30.00 to $27.84. The total temporary surcharges would be $27.84 per customer X 83 customers X 3 months = $6,932.

EVIDENCE AND CONCULSIONS FOR FINDINGS OF FACT NOS. 11 THROUGH 13

HIPOA witness Bostwick testified that the balance in HIPOA's checking account on December 31, 2011, was $3,659, and the HIPOA December 1, 2011, balance sheet reflected a negative $9,127 total assets.

Public Staff witness Bradley testified that the financial analysis of HIPOA's financial statements by Public Staff Financial Analyst Calvin Craig reflected that HIPOA has an extremely weak financial position and is teetering on the brink of insolvency. In particular, Mr. Craig stated in his affidavit that HIPOA does not currently possess the financial resources necessary to continue to provide water and sewer utility service at Camp Holiday and that given HIPOA's current financial condition, it is very unlikely that HIPOA will be able to obtain the funding necessary to continue to provide water and sewer service in its service area.

Witness Bradley observed that the sewer revenues are in the general vicinity of the sewer expenses, but her calculation was performed before the decrease in sewer customers from 90 to 83. She explained that the monthly sewer revenues of approximately $35 per month per customer with the reduction from 90 customers to 83, leaves a deficit on a monthly basis between revenues and expenses.

Public Staff witness Bradley remarked that the last Public Staff audit conducted on HIPOA's revenues and expenses was performed during HIPOA's last rate case proceeding, in Docket No. W-386, Sub 15, which was based on a test period of 12 months ended December 31, 2004; and she was the accountant assigned to that case. Witness Bradley explained that she compared the operating and maintenance expenses deemed reasonable during the last rate case to those provided in HIPOA Treasurer Elaine Mazur's prefiled testimony in this present docket. Witness Bradley further testified that for the purpose of determining the need for a surcharge in this particular case, she does not feel that the expenses Ms. Mazur presented are out of line. In addition, witness Bradley reported that the customer count has dropped from 98 in the Sub 15 rate case proceeding to the current customer level of 83. As witness Bradley testified, based on the average monthly sewer bill of $35, the resulting decrease in monthly revenues for the loss of 15 customers would be $525.

Additionally, witness Bradley maintained that it would not make sense under the unique circumstances of this case for HIPOA to file a general rate case rather than apply for the temporary surcharge and emergency assessment. She asserted that the unique circumstances in this proceeding are that HIPOA has filed an application to discontinue water and sewer utility services, and the hearing has been tentatively postponed until June 15, 2012, to allow the customers time to form a sanitary district. She observed that a rate case normally takes about seven months to complete, including the time needed to place the Commission approved rates into effect. She further testified that since it is the desired objective of all of the parties that the transfer to a sanitary district be accomplished, it would not make sense to pursue a general rate increase that assumes that HIPOA would continue as a regulated public utility.

Further, witness Bradley testified that a general rate case would create for HIPOA, and the customers, significant additional rate case expenses which the Public Staff believes should be avoided under these unique circumstances. Witness Bradley stated that it is the Public Staff's recommendation that HIPOA needs the emergency assessment to repay the outstanding debt of $6,917 for the 2011 sewer plant improvement renovations, and needs the temporary surcharge for the day-to-day operations of the system, including necessary repairs and renovations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

Public Staff witness Bradley testified that she was informed by David May, the regional supervisor for DWQ who prefiled testimony earlier in this proceeding, that the temporary surcharge was necessary for HIPOA to continue to operate the sewer system. Mr. May informed the Public Staff that DWQ was concerned that if money is not available, the system will go under and that the company needs adequate funds to continue, especially funds for repairs.

DWQ also informed the Public Staff that at the time of the January 31, 2012, hearing date there was at least one or two pumps out at the sewer plant that needed to be repaired, and HIPOA has no money to make the repairs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15 AND 16

Public Staff witness Bradley recommended that the emergency assessment funds collected be placed into HIPOA's ECIA account and that such funds be used to repay the loan of $6,917 for the sewer plant improvement renovations performed during the summer of 2011. She testified that normally these type of sewer plant improvement renovations would be paid from the ECIA account, but the ECIA account balance as of October 21, 2011, was $313, and as of December 31, 2011, the ECIA account balance was $293.

In addition, witness Bradley proposed that the Commission require accounting and reporting requirements as follows:

> HIPOA be required to file a report with the Commission on a monthly basis, due no later than 20 days after the end of the month, that includes (1) the number of customers at the end of the month, (2) the surcharge amounts collected from each customer during the month, (3) the assessment amounts collected from each customer during the month, (4) the income statement for the month detailing the amounts for revenues and expenses, (5) copies of the monthly bank statements, and (6) documentation supporting any expenditures. The Public Staff further recommended that the report list any customer(s) that have requested termination of sewer service by lot number and indicate whether that individual was receiving direct or indirect sewer service.

Witness Bradley stated that the Public Staff would review the HIPOA monthly reports filed with the Commission and the documentation for the expenditures utilizing the temporary surcharge funds.

The Public Staff also recommended that the temporary surcharge funds be maintained in a separate account so that the balance of the temporary surcharge funds and the balance in the ECIA account (if any after the loan repayment) can be transferred with the system to the sanitary district.

Based upon the evidence presented, the Commission concludes that the sewer plant facilities were inadequate during the summer of 2011, when the improvements were made. The Commission further concludes there is no reasonable probability of HIPOA obtaining the capital necessary to pay for the necessary system improvements from sources other than the customers.

The Commission finds and concludes that the ECIA account has been substantially depleted, and there are inadequate ECIA funds to pay for the $6,917 sewer system renovations which were done during the summer of 2011. The Commission approves an emergency assessment of $27.78 per customer for three months (based upon the 83 sewer customers on January 31, 2012, this should total $6,917, when collected). The Commission approves the repayment of the $6,917 loan.

In addition, the Commission is also of the opinion that it is appropriate for HIPOA to have adequate funds during the pendency of this proceeding to operate the sewer utility system and make necessary repairs and renovations. The Commission understands that, without a temporary surcharge, HIPOA does not have adequate funds for system operations, for necessary repairs, and for necessary system improvements. The Commission finds and concludes that the current monthly sewer revenues are inadequate (with the decrease in the number of sewer customers, there is now a monthly operating deficit whereby monthly operating revenues are less than monthly operating expenses).

Consequently, based upon the unique circumstances of this proceeding, the Commission also approves a temporary surcharge in the amount of $27.84 per customer per month for a period of three months.

IT IS THEREFORE, ORDERED as follows:

1. That HIPOA is authorized to bill each sewer customer an emergency assessment of $27.78 per month for each of the next three monthly sewer utility billings after the date of this Order.

2. That all the monthly emergency assessment funds collected by HIPOA shall be deposited into the existing ECIA account.

3. That HIPOA is authorized to utilize the emergency assessment funds collected to repay the loan made by the homeowners association to HIPOA to cover the cost of the sewer plant improvements during the summer of 2011.

4. That HIPOA is also authorized to bill each sewer customer a temporary surcharge of $27.84 per month for each of the next three monthly sewer utility billings after the date of this Order.

5. That all the monthly temporary surcharge funds collected by HIPOA shall be deposited into a newly established account solely containing the temporary surcharge funds.

6. That each month, until further Commission order, HIPOA shall file with the Commission on or before the 20th day after the end of the month a report and supporting documentation for the previous month which includes:

(a) The number of customers at the end of the month;
(b) The temporary surcharge amounts collected from each customer during the month;
(c) The emergency assessment amounts collected from each customer during the month;
(d) The income statement for the month detailing the amounts for revenues and expenses;
(e) Copies of the monthly bank statements for the HIPOA operating account, the ECIA account and the temporary surcharge account;
(f) Documentation supporting any expenditures from the ECIA and temporary surcharge accounts; and
(g) A list of any customers that may have requested termination of sewer service by lot number including stating whether that customer had been receiving direct or indirect sewer service.

HIPOA shall provide Lloyd C. Smith, III, the attorney for the intervener Minzies Creek Village, with a copy of each monthly report and supporting documentation filed with the Commission pursuant to this paragraph.

7. That the Public Staff shall review each HIPOA monthly report and all supporting documentation and report to the Commission should the Public Staff believe that there are inappropriate items in the report and/or documentation.

8. That should the water and sewer systems in the future be transferred after Commission approval to a sanitary district formed by the customers, the remaining balance in the separate temporary surcharge account and the remaining balance in the ECIA account (if any after the loan repayment) shall be transferred to the sanitary district.

9. That HIPOA is authorized after written notice as required by Commission Rule 10-16(c) to discontinue the sewer utility service of any customer that fails to pay either the emergency assessment or temporary surcharge by the past due date of 30 days after the billing date.

10. That a copy of this Order shall be mailed with sufficient postage or hand delivered to all affected customers within five business days of the date of this Order, and HIPOA shall submit the attached Certificate of Service properly signed and notarized not later than 10 business days after the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the _4th__ day of _April_, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

rb040412.01

WATER AND SEWER – DISCONTINUANCE

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-386, Sub 18, and such Order was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________ 2012.

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-386, Sub 18.

Witness my hand and notarial seal, this the ______ day of _____________ 2012.

____

Notary Public

____

Address

(SEAL) My Commission Expires: ____________________________________

Date

DOCKET NO. W-1282, SUB 8

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Pluris, LLC, 2100 McKinney Avenue, Suite 1550, Dallas, Texas 75201, for Authority to Increase Rates for Sewer Utility Service in All of Its Service Areas in Onslow County, North Carolina	)))))	ORDER GRANTING PARTIAL RATE INCREASE AND REQUIRING CUSTOMER NOTICE

HEARD IN: North Topsail Beach Town Hall, 2008 Loggerhead Court, North Topsail Beach, North Carolina, on Thursday, August 9, 2012, at 7:00 p.m.

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Tuesday, September 11, 2012, at 9:00 a.m.

BEFORE: Commissioner Bryan E. Beatty, Presiding; and Commissioners ToNola D. Brown-Bland and Lucy T. Allen

APPEARANCES:

For Pluris, LLC:

Christopher J. Ayers, Poyner Spruill, LLP, 301 Fayetteville Street, Suite 1900, Raleigh, North Carolina 27601

For the Using and Consuming Public:

William E. Grantmyre, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On October 31, 2011, Pluris, LLC (Pluris, Company, or Applicant), filed a letter of intent notifying the Commission of its intent to file a general rate case application as required by Commission Rule R1-17(a). On December 9, 2011, Pluris filed an updated letter of intent with the Commission.

On February 15, 2012, Pluris filed an Application (Original Application) with the Commission seeking authority to increase its rates for sewer utility service in all of its service areas in Onslow County, North Carolina. The Company's proposed rates would increase the average monthly bill by approximately 97%, except that customers with grinder pumps would also be required to pay an additional maintenance fee of $5.00 per month, as proposed by the Company.

The intervention and participation in this docket by the Public Staff is made and recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). No other party intervened in this proceeding.

By Order issued February 28, 2012, the Commission declared the matter to be a general rate case pursuant to G.S. 62-137; suspended the proposed new rates for up to 270 days pursuant to G.S. 62-134; scheduled the application for public hearing in North Topsail Beach, North Carolina, and for evidentiary hearing in Raleigh, North Carolina; and required customer notice of the proposed rate increase and hearings. On April 5, 2012, the Company filed a Certificate of Service notifying the Commission that the required notice to customers had been provided.

On April 24, 2012, Pluris filed a Motion to Amend General Rate Case Application (Motion to Amend) to correct errors in the rate base and revenue requirement calculations in its Original Application and to revise its applied for rates, resulting in an applied for increase of approximately 149% instead of the initially requested increase of approximately 97%. On April 27, 2012, the Public Staff filed its response to the Motion to Amend recommending that the Commission allow such motion.

By Order issued May 1, 2012, the Commission allowed the application amendments, suspended rates, rescheduled the customer and evidentiary hearings, and required customer notice. The Order also reset the rate suspension dates and dates for filing testimony by the parties. On May 11, 2012, Pluris filed its Certificate of Service indicating that customer notice was provided as required by the Commission's May 1, 2012 Order.

On July 23, 2012, Pluris filed the direct testimony of its witnesses Maurice W. Gallarda, P.E., Managing Member, Pluris Holdings, LLC, and Robert C. Nixon, CPA with CJN&W Certified Public Accountants. Also on July 23, 2012, Pluris filed a motion requesting that the Commission grant an extension of time for the filing of rate of return testimony until August 13, 2012. On July 24, 2012, the Commission issued an Order Extending Time to File Testimony.

On August 9, 2012, the customer hearing was held as scheduled in the North Topsail Beach Town Hall, North Topsail Beach, North Carolina. The following 28 customers presented testimony at the public hearing: Thomas Rhyne, III, Edward Miller, Kevin Reynolds, David Willette, Linda Schneider, Frank Green, Robert Chasserot, Ann Palmer, Anthony Fiore, Carl McMasters, Floyd McKissick III, Carl Ward, Tim Supple, Frances Parsons, James Heath, Thomas Leonard, Kevin Eitel, Carla Torrey, Tony Caminiti, Dan Tuman, Mallory Leimone, Annette Ramey, Lori Burnette, Dale Denning, Jay Greenspan, Art Stow, Richard Peters, and Eddie Wilcox.

On August 13, 2012, Pluris filed the direct testimony of its rate of return witness, Pauline M. Ahern, CRRA, with AUS Consultants. On August 16, 2012, the Public Staff filed a motion for extension of time to file its testimony which was granted by Commission Order issued that same date. On August 24, 2012, the Public Staff filed the testimony and exhibits of Windley E. Henry, Staff Accountant, Public Staff Accounting Division; Jerry H. Tweed, Utilities Engineer, Public Staff Water Division; and John R. Hinton, Director, Public Staff Economic Research

Division. On that same date, the Public Staff and Pluris (collectively, the Stipulating Parties) entered and filed a Partial Settlement Agreement which stipulated to the appropriate capital structure and cost rates on the components of the capital structure and return on rate base for this proceeding and included an agreement between the Stipulating Parties to waive the right to cross-examine each other's rate of return witness. On August 30, 2012 Pluris filed a petition to admit the prefiled direct testimony of Pauline M. Ahern into evidence without the need for such witness to appear in person at the evidentiary hearing scheduled for September 11, 2012. On September 7, 2012, the Commission issued an Order Granting Motion to Excuse Witness and Admitting Prefiled Testimony and Exhibits into Evidence. On September 5, 2012, Pluris filed the rebuttal testimony of Maurice W. Gallarda.

On September 11, 2012, the evidentiary hearing was held in Raleigh, North Carolina as scheduled. No public witnesses testified at the hearing. Pluris presented the direct and rebuttal testimony of Maurice W. Gallarda and the direct testimony of Robert C. Nixon. The Public Staff presented the testimony of its witnesses Windley E. Henry, Jerry H. Tweed, and John R. Hinton.

In an oral order from the bench, at the September 11, 2012 hearing, the Commission required the Company to file a late-filed exhibit regarding the Company's educational program to promote prevention of damage to simplex sewer grinder pump stations. In addition, the Commission granted the Company's request to allow the filing of a late-filed exhibit to update Pluris' actual rate case expense up to the time of filing its proposed order.

On September 19, 2012, Pluris filed a late-filed exhibit concerning prevention of grinder pump damage. The Company presented its proposed informational material and customer letter (1) for the purpose of raising awareness of customer responsibility for the repair and/or replacement of the grinder pump if damage is shown to be due to homeowner negligence and (2) for promoting damage prevention practices by identifying items/materials which should not be flushed down toilets or disposed of in sink drains. On September 25, 2012, the Public Staff filed a letter recommending Commission approval of Pluris' educational program as being appropriate for implementation and mailing to the customers.

On October 25, 2012, the Public Staff filed its Proposed Order. On that same date, Pluris filed a letter stating that the Company had reviewed the Public Staff's Proposed Order, accepted the Public Staff's proposed adjustments for the purpose of resolving the issues in this proceeding, and as a result, would not submit a separate proposed order. Pluris requested that the Commission adopt the Public Staff's Proposed Order as soon as reasonably possible to allow the Company to implement the recommended rates.

Also, on October 25, 2012, Pluris filed a late-filed exhibit updating its rate case expense up to the time of the filing of proposed orders.

Based upon the Original Application and the Amended Application (collectively, the application), the Partial Settlement Agreement, the evidence adduced at the hearing, and the entire record in this proceeding, the Commission now makes the following

FINDINGS OF FACT

General Matters

1. Pluris is a public utility as defined by G.S. 62-3(23) and is authorized to provide sewer utility service in its service areas in Onslow County pursuant to a franchise granted by the Commission on September 3, 2009, in Docket No. W-1282, Sub 0.

2. Pluris is properly before the Commission, pursuant to Chapter 62 of the General Statutes of North Carolina, for a determination of the justness and reasonableness of its proposed rates and charges.

3. The test period appropriate for use in this proceeding is the 12 months ended December 31, 2011, updated to June 30, 2012.

4. Pluris provides sewer utility service to approximately 3,350 residential and 135 commercial customers in its North Topsail Beach and Sneads Ferry Service Areas in Onslow County, North Carolina.

5. The sewer system owned and operated by Pluris uses approximately 78 miles of gravity and force mains; 664 pump stations; a 542,635 gallon per day (gpd) lagoon type wastewater treatment system with 129 acres of spray irrigation area; and a 500,000 gpd newly constructed Membrane Biological Reactor (MBR) wastewater treatment plant with a high-rate infiltration disposal system.

6. The construction of the new MBR Plant was completed in November 2011. Pluris is currently able to meet 100% of the sewer capacity demand in the North Topsail Beach and Sneads Ferry Service Areas.

7. The quality of service provided by Pluris to its customers is adequate.

8. The Commission received 51 email messages and letters from 44 different customers with one letter containing a petition with 21 signatures. All of the customers objected to the magnitude of the proposed rate increase, while some also expressed a desire for metered rates for residential sewer service. In addition, 28 public witnesses testified at the hearing in North Topsail Beach. The concerns expressed by customers included the following: opposition to the magnitude of the proposed rate increase; a desire for metered residential sewer rates instead of flat rates; lack of adequate customer notice; and insufficient information to understand the reason/need for the proposed rate increase. None of the customers who testified expressed quality of service complaints.

Rate Base

9. Pluris' reasonable original cost rate base at December 31, 2011, updated to June 30, 2012, including pro forma adjustments, is $8,713,424, consisting of the following items:

Plant in service	$ 25,012,348
Accumulated depreciation	(5,966,815)
Contributions in aid of construction (CIAC)	(12,015,541)
Accumulated amortization of CIAC	4,112,159
Prepaid tap-on fees	(2,507,443)
Customer deposits	(18,120)
Accumulated deferred income taxes (ADIT)	(197,631)
Deferred charges	132,682
Cash working capital	178,770
Average tax accruals	(16,985)
Original cost rate base	$ 8,713,424

Revenues

10. The appropriate annual level of total operating revenues for Pluris under present rates for use in this proceeding is $1,400,839, consisting of service revenues of $1,394,226 and miscellaneous revenues of $6,613.

11. Pluris requested an increase in its sewer utility rates that would produce additional service revenues of $2,102,513. The appropriate annual level of total operating revenues under proposed rates for use in this proceeding is $3,503,352, consisting of service revenues of $3,496,739 and miscellaneous revenues of $6,613.

Operating Expenses

12. It is appropriate to update rate case expense, as proposed by Pluris in its late-filed exhibit filed on October 25, 2012, to include the additional amount of rate case expense incurred by Pluris up to the time of the filing of proposed orders.[1] Pluris' total rate case costs for this proceeding, as updated in its late-filed exhibit filed on October 25, 2012, are $149,023, consisting of $65,623 in contract service fees; $42,395 in accounting fees; $27,987 in legal fees; $7,500 for the cost of capital witness; $1,432 in travel-related costs; and $4,086 for postage, paper stock, printing, and miscellaneous costs. It is appropriate to amortize these total rate case costs of $149,023, over a five-year period, resulting in a rate case expense of $29,805 to be included in the Company's total operating expenses used to establish rates in this proceeding.

13. The reasonable level of total operating expenses under present rates to be included in this proceeding is $1,430,163, which consists of the following components:

Contract services	$ 508,278
Sludge removal	41,616
Purchased power	193,029
Chemicals	63,092
Testing	25,968

[1] As previously mentioned, Pluris declined to prepare and submit a proposed order. The updated rate case expenses, as filed by the Company, have been reflected in the Public Staff's Proposed Order in its calculation of operating expenses and its proposed revenue requirement and the resulting rates.

Maintenance & repair	115,196
Materials & supplies	5,830
Permit fees	2,620
Alarm line expense	51,756
Vehicle expense	71,997
Management fees	205,901
Consulting fees	568
Legal fees	12,013
Accounting fees	9,400
Outside services	3,365
Other fees	201
Cleaning services	3,230
Utilities	12,763
Insurance	38,184
Miscellaneous expenses	35,351
Rate case expense	29,805
Total operating expenses	$1,430,163

Depreciation, Amortization, and Taxes

14. It is reasonable and appropriate to calculate regulatory fees using the statutory rate of 0.12%; gross receipts taxes using the statutory rate of 6% for sewer operations; and state and federal income taxes using the corporate tax rates of 6.9% for state income taxes and 34% for federal income taxes.

15. The appropriate level of total depreciation, amortization, and taxes under present rates to be reflected in this proceeding is $374,558, summarized as follows:

Depreciation expense	$ 757,608
Amortization expense – CIAC	(469,130)
Property tax	349
Payroll tax	0
Regulatory fee	1,681
Gross receipts tax	84,050
State income tax	0
Federal income tax	0
Total depreciation, amortization, & taxes	$ 374,558

Overall Cost of Capital

16. The appropriate overall rate of return on rate base is 7.67%, which is based upon a capital structure of 57.81% long-term debt with an embedded cost of debt of 6.12%, and 42.19% common equity with a return on common equity of 9.80%.

Rates, Fees, and Other Matters

17. Pluris' proposed $5.00 grinder pump maintenance fee for residential customers with individual simplex grinder pump stations is not appropriate for purposes of establishing rates in this proceeding.

18. Pluris' proposal to include language in its tariff which will make homeowners liable for the cost of repair or replacement of simplex grinder pumps damaged due to homeowner negligence is appropriate and should be approved.

19. Pluris' present and proposed rates, as provided in its Amended Application filed on April 24, 2012, for sewer utility service are as follows:

	Present	Proposed
Monthly Residential Flat Rate:		
Customers with individual pump stations, Where customer pays the electric expense for pumping	$29.15	$72.55
All other residential customers	$31.65	$78.77

	Present	Proposed
Monthly Non-Residential Metered Rates:		
Base charge, zero usage	$15.20	$37.83
Usage charge, per 1,000 gallons	$ 4.83	$12.02
Monthly Grinder Pump Maintenance Fee:		
Customers with a grinder pump	N/A	$ 5.00

20. There is insufficient data available in this proceeding to establish a residential metered sewer rate based upon metered water usage.

21. It is appropriate in this proceeding to establish a single flat monthly residential sewer rate for all customers, whether they are served by an individual grinder pump station or by a gravity flow connection.

22. Ongoing sewer rates should be established to produce $2,783,962 in total annual operating revenues, of which $2,777,349 relates to service revenues and $6,613 relates to miscellaneous revenues. This annual level of total operating revenues will provide the Applicant with an opportunity to earn the 7.67% overall rate of return on its rate base found just and reasonable. The rates approved herein will produce annual service revenues of $2,777,349 which represents an increase of $1,383,123 or 99.20% over total annual service revenues produced under existing rates.

23. The following monthly sewer rates should produce the annual level of service revenues approved in this Order:

Monthly Residential flat rate:	$62.35
Monthly Non-Residential metered rate:	
Base charge, zero usage	$30.35
Usage charge, per 1,000 gallons	$ 9.68

<u>Accounting Matters</u>

24. The contract operators should keep track of their time spent on capital projects in order to allocate a portion of their salary and benefits to the cost of each project.

25. Pluris Managing Member, Maurice W. Gallarda, should keep track of his time spent on capital projects and business development so that a portion of his salary and benefits can be capitalized.

26. The reconciliation of the budgeted versus actual expenses incurred by Utility Partners, LLC[1] on behalf of Pluris should be completed on a monthly basis with each expense recorded in Pluris' general ledger using the appropriate expense account as set forth in the National Association of Regulatory Utility Commissioners (NARUC) Uniform System of Accounts.

27. Management fees allocated to Pluris from Pluris Holdings, LLC should be recorded in the appropriate NARUC expense account in Pluris' general ledger.

28. The allowance for funds used during construction (AFUDC) should be calculated on long-lived construction projects using the overall costs rates approved in Pluris' most recent general rate case proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 THROUGH 4

The evidence supporting these findings of fact is contained in the application and in the Commission's records. These findings are primarily jurisdictional and informational and are uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 AND 6

The evidence supporting these findings of fact is contained in the application; in the Commission's records; in the testimony of Public Staff witness Tweed; and in the direct testimony of Pluris witness Gallarda.

In his prefiled testimony, Public Staff witness Tweed described the various components of the sewer system used by the Applicant to provide sewer utility service to its customers and stated that he and other members of the Public Staff had also inspected such wastewater treatment and disposal facilities and portions of the wastewater collection system throughout the

[1] Pluris has entered into a professional utility management services contract with Utility Partners, LLC to operate, manage, and provide labor for the wastewater utility system located at North Topsail Beach.

service territory. Witness Tweed testified that he had contacted Jim Bushardt, an Environmental Engineer located in the Wilmington regional office of the Division of Water Quality (DWQ) of the North Carolina Department of Environment and Natural Resources (DENR), to inquire whether DWQ had any concerns regarding such system. According to witness Tweed, Mr. Bushardt expressed that DWQ was pleased with the new MBR wastewater treatment plant and high-rate infiltration system. Mr. Bushardt advised witness Tweed that the new MBR Plant is much better environmentally than the older lagoon and spray irrigation system, especially in heavy rain events when spray irrigation is not possible. Mr. Bushardt also advised witness Tweed that the quality of the wastewater effluent from the new MBR Plant is much better than the wastewater effluent from the older lagoon system. Witness Tweed testified that he also spoke with Jim Gregson, DWQ Surface Water Protection Supervisor, who stated that Pluris was doing a good job and DWQ had no problems with the collection system operation.

Witness Tweed observed that the sewer system had been under a DWQ moratorium with a waiting list of customers to be served just prior to Pluris' acquisition of the system from North Topsail Utilities, Inc. (NTUI) in 2009.[1] Witness Tweed pointed out that in the transfer proceeding, the Town of North Topsail Beach (Town), an intervenor, and Onslow Water and Sewer Authority (ONWASA) supported a requirement that Pluris be required to construct a 2.0 million gpd wastewater treatment plant on a specific timetable to ensure that adequate capacity was available to service the anticipated explosive growth in the service area. The Town and ONWASA further recommended that Pluris be required to post a $12 million bond to ensure the treatment plant was constructed on the established timetable. According to witness Tweed, the Public Staff recommended, and the Commission approved, a phasing in of the plant construction in order to avoid an excess capacity issue and the extremely high rates that could be associated with the excess investment. Witness Tweed testified that Pluris' new 500,000 gpd MBR Plant is constructed such that it can be easily expanded to accommodate growth by adding an additional 500,000 gpd treatment unit.

Witness Gallarda testified that Pluris acquired the sewer utility system from Utilities, Inc. in 2008 and, that at the time of acquisition, the North Topsail system had been at maximum capacity for a number of years, resulting in a moratorium on connections and a waiting list of approximately 500 people to receive sewer utility service. Further, he commented that such limited sewer capacity was a critical issue in the transfer proceeding raised by the Town, the Public Staff, and the Commission, and that Pluris had committed to resolve such capacity issue upon completion of the transfer.

In response to the capacity demands, witness Gallarda testified that Pluris constructed a MBR Plant at an approximate cost of $8 million, which represented a construction cost of approximately $8.00 per gallon. He stated that Pluris completed the construction of its MBR Plant in November 2011. As a result, the waiting list for sewer utility service was eliminated and new homes and businesses can be constructed and connected to the system. Witness Gallarda contended that Pluris is currently able to meet 100% of the demand in the

[1] On August 26, 2008, in Docket No. W-1282, Sub 0, Pluris and North Topsail Utilities Inc. (NTUI), filed a joint application for authority to transfer the sewer utility system assets and franchise for the North Topsail Beach and Sneads Ferry Service Areas in Onslow County, North Carolina from NTUI to Pluris. NTUI was a wholly owned subsidiary of Utilities, Inc. On July 10, 2009, the Commission issued an Order Approving Transfer.

service area. He commented that as further growth requires additional system capacity, a second cell can be constructed in approximately 16 weeks; consequently, he believes Pluris has completely resolved the sewer capacity issue for the service area.

Based upon the evidence presented, the Commission is of the opinion and so concludes that as a result of the newly constructed MBR Plant, Pluris is currently able to meet 100% of the sewer capacity demand in the North Topsail Beach and Sneads Ferry service areas.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7 AND 8

The evidence supporting these findings of fact is contained in the Commission's records; in the testimony of the public witnesses; in the testimony of Public Staff witness Tweed; and in the direct and rebuttal testimony of Pluris witness Gallarda.

At the public hearing held on August 9, 2012, in North Topsail Beach, a total of 28 public witnesses testified. All 28 public witnesses opposed the proposed rate increase and expressed concerns about the magnitude of the proposed rate increase. Ten public witnesses expressed a desire for metered residential sewer rates.[1] A number of witnesses expressed concern about customers not receiving adequate customer notice of the August 9, 2012 rescheduled customer hearing and some customers expressed concern that insufficient information was provided to understand the reason/need for the proposed rate increase. None of the 28 public witnesses testified regarding quality of service complaints.

Witness Gallarda testified that the Pluris service area has not experienced a rate increase in 17 years.[2] Witness Gallarda explained that, although at the time Pluris acquired the system in 2009 a rate increase for the system was long overdue, Pluris agreed with the Public Staff's recommendation that it would postpone requesting an increase in rates until the transfer from NTUI was completed along with the construction of the MBR Plant. Pluris agreed that it was more efficient to proceed with a single rate case upon completion of those events, as opposed to filing two general rate case applications in rapid succession. Witness Gallarda commented that the Company's decision to postpone requesting an increase in rates at the time of the transfer proceeding was apparently misunderstood by some customers as several asserted at the August 9, 2012 hearing that Pluris had stated it would not raise rates following the acquisition of the system from NTUI. In rebuttal testimony, witness Gallarda clarified the Company's position. In particular, he stated that Pluris "would not increase rates as a result of the transfer and would

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[1] This customer concern is subsequently discussed and addressed in the Evidence and Conclusions for Findings of Fact Nos. 20 and 21 herein.

[2] In the Commission's Order Granting Franchise, Approving Rates, and Requiring Customer Notice issued on September 3, 2009, in Docket No. W-1282, Sub 0, the rates approved for Pluris did not change from those previously charged by NTUI. On June 28, 2000, in Docket No. W-1143, Sub 0, the Commission issued an Order Approving Transfer and Requiring Customer Notice, which allowed the transfer of the North Topsail Beach and Sneads Ferry service areas from Utilities, Inc. to NTUI, a newly established wholly owned subsidiary of Utilities, Inc. In that proceeding, the rates approved at the time of transfer did not change from those previously charged by Utilities, Inc. The rates charged for the North Topsail Beach and Sneads Ferry service areas by Utilities, Inc. were established in Docket No. W-1000, Sub 5, pursuant to the Commission's Order issued on February 8, 2000. Such rates were the same rates as those previously established pursuant to a Recommended Order issued on June 7, 1995, in Docket No. W-754, Sub 19 for North Topsail Water and Sewer, Inc., a prior owner of the sewer system.

not seek to recover an acquisition premium or acquisition costs through rates. Pluris did not agree to forego rate cases when operating costs and new investments necessitated them."

With respect to the customer concern that the construction of the MBR Plant has created the need for the present rate increase, witness Gallarda testified that Pluris has taken steps to help offset the cost of the MBR Plant. He stated that Pluris amended the original MBR Plant design, resulting in cost savings of approximately $10 million. Witness Gallarda explained that Pluris constructed a base facility with one cellular unit, which will allow for expansion in the future as customer growth requires. He explained that the use of cells allows for more cost-effective expansion rather than construction of another new treatment facility in the future. Under cross-examination, witness Tweed agreed that Pluris had addressed the sewer capacity demand issues in a cost-effective manner.

Witness Gallarda testified that, in Docket No. W-1282, Sub 6 (Sub 6 Proceeding),[1] the Commission approved Pluris' request to increase its connection fee from $2,000 to $3,600 per single-family equivalent (SFE), which has helped to offset a portion of the MBR Plant costs. During cross-examination, he explained that in the Sub 6 Proceeding a SFE was defined as (1) a three-bedroom home not on the barrier island, (2) a three-habitable room home on the barrier island, or (3) a multi-family residence unit up to three bedrooms. He stated that in the Sub 6 Proceeding the Commission also approved Pluris' request to charge an amount of $1,200 per each additional bedroom not on the barrier island and for each additional habitable room on the barrier island above the SFE in addition to the base SFE connection fee of $3,600.[2] Witness Gallarda explained that one of the reasons for the sewer capacity issues was because people began building larger homes with up to nine bedrooms in their residences rather than the typical four to five bedroom homes previously constructed. He stated that for purposes of capacity planning, the customer in those circumstances was actually adding two single family residences, not just the one. Witness Gallarda testified that the additional $1,200 amount charged above the SFE helps to offset the construction cost of the new MBR Plant and this charge is only applicable to customers requiring that additional capacity.

Further, Witness Gallarda testified that in the Sub 6 Proceeding the Commission also approved the Company's request to charge the actual cost of materials and labor for installing a simplex pump station and service line and making a road bore (when required to service a particular lot) although those type services were previously included in the $2,000 tap-on fee amount. Witness Gallarda maintained that the costs of the grinder pump alone was approximately $2,000, which did not include the related labor costs. Consequently, prior to the revision to the tap fee, none of the $2,000 tap fee amount was available to help offset the cost of the sewer capacity. With the recent revisions to Pluris' tariff to charge separately for the actual cost of materials and labor for installing the simplex pump station with service line and making a

[1] On October 18, 2011, in Docket No. W-1282, Sub 6, the Commission issued an Order Approving Tariff Revision which granted Pluris a tariff revision to increase its connection fees, and to charge the actual cost of materials and labor for installing a simplex pump station with service line and making a road bore.

[2] For example, the connection fee for a non-barrier island four-bedroom residence or four-habitable-room barrier island residence is $3,600 plus $1,200 or $4,800. The connection fee for a five-bedroom non-barrier island residence or five-habitable-room barrier island residence is $3,600 plus $2,400 or $6,000.

road bore, he contended that the tap-on fee amount will be better used to offset the cost of the new MBR Plant.

Witness Tweed testified that the cost of construction of the new facilities is the prime driver behind the rate increase request in this proceeding. During cross-examination, witness Tweed testified that the newly constructed MBR Plant will benefit all customers in the service area in the future because eventually all of the wastewater will be treated through the expanded MBR Plant as the use of the older lagoon type system will be phased out of service. Witness Tweed further explained that although the lagoon system is currently meeting the needs of the customers served by the system, it is an undesirable situation according to DWQ because of heavy rain events and the inability to spray effluent on the spray fields during such weather events. He pointed out that a dilemma is created during heavy rain events because there is higher flow coming into the wastewater lagoon system that needs to be removed and sprayed on the spray fields, which is not an option when those spray fields are wet. Witness Tweed maintained that the MBR treatment process is much superior to the lagoon type system, as the MBR treatment process, which includes the use of a high-rate infiltration pond, is not as impacted by significant rainfall or other weather events.

With respect to the concern expressed by some of the public witnesses that they had not been provided adequate customer notice of the August 9, 2012 rescheduled customer hearing, Company witness Gallarda testified that Pluris undertook an internal investigation to confirm that the amended customer notice was, in fact, mailed to customers. As a result of its investigation, witness Gallarda maintained that the amended customer notice was actually mailed in accordance with the Commission's May 1, 2012 Order. Further, witness Gallarda explained that Pluris received a written confirmation dated May 9, 2012, that the mailing company, California Marketing had mailed 2,433 amended customer notices and that such pieces of mail were delivered directly to the Pasadena, California Post Office facility, as has been the practice for all monthly billings and notices since Pluris acquired the utility. Pluris observed that a number of the customers stated that they had received the first postcard, but not the second postcard. Witness Gallarda pointed out that Pluris mailed the original and amended customer notices via letters, rather than via postcards. Witness Gallarda expressed that the postcard mailings may have been undertaken by local homeowners' associations or community groups, but that he was unaware of the origin or distribution of such postcard mailings.

Further, during cross-examination witness Gallarda testified that the difference (1,067) between the 2,433 number of customer notices mailed by Pluris and the 3,500 customers referenced in the testimony of Public Staff witness Tweed is due to the number of customers that reside in condominium or homeowners' associations. He explained that Pluris sends its monthly bills and other required mailings to the condominium and homeowners' associations and not to the individual customers within those associations. He stated that it is the responsibility of those associations to deliver such mailings to its members. Witness Gallarda maintained that the mailing list Pluris used to mail the 2,433 customer notices is the same list the Company uses to mail its monthly bills to customers. Furthermore, witness Gallarda commented that the Company does not have the individual addresses of the units within the condominium and homeowners' associations.

In regard to the customers' concern that they did not receive sufficient information to understand the reason/need for the proposed rate increase, witness Tweed testified that after the conclusion of the August 9, 2012 customer hearing, he talked with several customers and explained that the requested information was available for public inspection on the Commission's website. Witness Tweed commented that there is a multitude of information available on the Commission's website concerning this general rate case proceeding and that those customers that expressed such concerns were probably seeking a simple accounting explanation regarding the need for the Company's proposed rate increase. On cross-examination, witness Tweed maintained that adequate information regarding the reasons for the proposed rate increase could be found on the Commission's website in Docket No. W-1282, Sub 8. Further, witness Tweed testified that the Public Staff did not receive any customer complaints since the filing of its testimony on August 24, 2012.

To address the customers' concern over the closure of the local office by the prior owners, witness Gallarda testified that Pluris has reopened the Sneads Ferry customer care center. Thereby, the customers can again walk in and pay their bills and meet with operations and billing staff to discuss any billing or operational concerns. The customer care center is open Monday through Friday, between the hours of 8:00 a.m. to 5:00 p.m.

Based upon the evidence presented, the Commission finds and concludes that the quality of service provided by Pluris to its customers is adequate.

With respect to the concern expressed by customers regarding the magnitude of the proposed rate increase, the Commission observes that witness Tweed testified that the cost of construction of the new MBR Plant is the prime driver behind the rate increase request in this proceeding. As addressed hereinabove in the Evidence and Conclusions for Findings of Fact Nos. 5 and 6, prior to Pluris' acquisition of the system from NTUI in 2009, the sewer system had been at maximum capacity for a number of years, resulting in a moratorium on connections by DWQ and a waiting list of approximately 500 people to receive sewer utility service. The Commission further notes that such limited sewer capacity was a critical issue in the transfer proceeding (Docket No. W-1282, Sub 0). It was an issue raised by the Town, the Public Staff, and the Commission. In that proceeding, Pluris committed to resolve such capacity issue and planned to construct an MBR Plant, if such plant was deemed feasible and necessary. In the Order approving the transfer, the Commission concluded that Pluris should work with DWQ to comply with DWQ requirements for the expansion of the wastewater treatment plant.

In regard to the cost of construction of the new MBR Plant, the Commission is of the opinion that Pluris has taken reasonable and prudent steps to help offset the cost of the MBR Plant. The Commission observes that Pluris amended the original MBR Plant design, resulting in cost savings of approximately $10 million. In particular, as recommended by the Public Staff and adopted by the Commission in the transfer proceeding, Pluris phased in the construction of the new MBR Plant by constructing a base facility with one cellular unit, which will allow for expansion in the future if customer growth requires such expansion. The Commission is of the opinion that such amended design has enabled Pluris to fully address the sewer capacity demand issues that existed at the time of the transfer proceeding in a cost-effective manner. Further, the Commission observes that in Docket No. W-1282, Sub 6, Pluris requested and received Commission approval: (1) to increase its connection fee from $2,000 to $3,600 per SFE; (2) to define an SFE for purposes of establishing the appropriate tap-on fee; and (3) to charge actual costs of materials and labor for installing a simplex pump station with service line and making a road bore (when required to service a particular lot), although those type services were previously included in the Commission-approved tap-on fee amount. The Commission recognizes that such measures have clearly helped and will continue to offset a portion of the MBR Plant constructions costs.

In addition, the Commission observes that witness Tweed testified that the newly constructed MBR Plant will benefit all customers in the service area because eventually all of the wastewater will be treated through the expanded MBR Plant as the use of the older lagoon type system will be phased out of service. Although the lagoon system is currently meeting the needs of the customers served by that system, the Commission understands that it is an undesirable situation according to DWQ because of heavy rain events and the inability to spray effluent on the spray fields during such weather events. The Commission understands that the MBR treatment process, which includes the use of a high-rate infiltration pond, is not significantly impacted by heavy rainfall or other weather events as is the lagoon type system.

Further, the Commission recognizes that the service areas served by Pluris have not experienced a rate increase in their monthly sewer rates in 17 years. The present monthly rates charged for the North Topsail Beach and Sneads Ferry service areas were established pursuant to a Recommended Order issued on June 7, 1995, in Docket No. W-754, Sub 19, concerning a general rate case proceeding for North Topsail Water and Sewer, Inc., a prior owner of the sewer system. The monthly sewer rates currently charged to customers did not change when the subsequent transfer to Utilities, Inc. occurred in February 2008 nor did any change occur with the transfer to Pluris in September 2009. Thus, it is not surprising that there is now a need for a substantial rate increase.

Based upon the foregoing, the Commission finds and concludes that Pluris has addressed the sewer capacity demand issues that existed for a number of years prior to the acquisition by Pluris in a cost-effective manner and, as a result, Pluris is in a much improved position to better serve its customers and provide an adequate quality of service.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is contained in the testimony and exhibits of Public Staff witnesses Tweed and Henry and in the testimony of Pluris witnesses Gallarda and Nixon.

The following table summarizes the final position of the Public Staff as presented in its Proposed Order with respect to Pluris' original cost rate base at December 31, 2011, updated to June 30, 2012, including pro forma adjustments:

Plant in service	$ 25,012,348
Accumulated depreciation	(5,966,815)
CIAC	(12,015,541)

Accumulated amortization of CIAC	4,112,159
Prepaid tap-on fees	(2,507,443)
Customer deposits	(18,120)
ADIT	(197,631)
Deferred charges	132,682
Cash working capital	178,770
Average tax accruals	(16,985)
Original cost rate base	$ 8,713,424

In his rebuttal testimony, witness Gallarda stated that while Pluris agrees with the vast majority of the Public Staff's recommended accounting adjustments, Pluris does not agree with all of the Public Staff adjustments. In particular, witness Gallarda testified that Pluris disagrees with the Public Staff's calculation of ADIT, the Public Staff's calculation of AFUDC, and the Public Staff's adjustment to place 80 acres of land back in plant in service.

In regard to the Public Staff's calculation of ADIT, witness Henry testified that Pluris did not include an amount in rate base for ADIT in its application; consequently, he calculated an amount for ADIT based upon Pluris' timing differences between costs expensed on the Company's books and the amount to be deducted for income tax purposes if Pluris was a C corporation. In this proceeding, witness Henry maintained that Pluris had some timing differences regarding depreciation, deferred maintenance, and rate case expense. Witness Henry explained that, based upon information provided by Pluris in response to Public Staff data requests, he calculated an amount for ADIT on tax depreciation in excess of book depreciation for the years ending December 31, 2009 through December 31, 2011, utilizing an effective tax rate of 38.55%. Further, witness Henry calculated amounts for ADIT related to the unamortized portion of sludge hauling expense and rate case expense recommended by the Public Staff in this proceeding also utilizing an effective tax rate of 38.55%.

In rebuttal testimony, witness Gallarda contended that the Public Staff reduced revenues by the tax benefit derived from the acquisition adjustment which resulted when Pluris acquired the sewer system from NTUI. Witness Gallarda maintained that Pluris should not be penalized in rates from an investment that Pluris made that is not included in rate base.

With respect to the Public Staff's calculation of AFUDC, witness Henry testified that Pluris did not have an overall cost rate to use from a prior rate case proceeding to calculate AFUDC on the MBR Plant. Instead, the Company used its proposed cost rate for this proceeding to calculate AFUDC. Witness Henry recommended that Pluris use its overall cost rate established by the Commission in the most recent general rate case proceeding in calculating the AFUDC on long-lived capital projects.

In rebuttal testimony, witness Gallarda disagreed with the Public Staff's recommendation that future AFUDC should be calculated on long-lived construction projects using the overall cost rates approved in the most recent general rate case proceeding. Witness Gallarda asserted that the condition of the financial markets in the future is unpredictable and treatment should be evaluated based on the conditions existing at the time of any future general rate case proceedings.

Concerning the Public Staff's adjustment to place 80 acres of land back in plant in service that the Company had removed from plant in service in its application, witness Henry maintained that the land is utility property and is currently being recovered through rates billed to customers on the system. Witness Henry contended that the customers have a vested interest in the land and any possible transactions that may affect future ownership of the land. Witness Henry explained that if the land was sold to a developer sometime in the future, any gain or loss on sale of the property could be flowed back to the ratepayers in the form of lower rates since customers have provided revenues to the Company to recover the cost of the land. Witness Henry commented that it is the general policy of the Commission that it is appropriate for ratepayers to receive the benefit of gains realized on the sale or transfer (disposition) of property which has been obtained by the utility in the course of providing regulated public utility service.

In rebuttal testimony, witness Gallarda disagreed with the Public Staff's adjustment to place 80 acres of land back in plant in service that the Company had removed from plant in service in its application. He explained that the 80 acres at issue consists of spray fields that were taken out of service pursuant to the DENR permit for construction of the MBR Plant. As the spray fields are no longer in use, they are not used and useful and should be excluded from plant in service. Witness Gallarda believes that some or all of the 80 acres may have been excluded from plant in service in prior rate case proceedings.

Despite these disagreements, witness Gallarda testified on cross-examination that Pluris is willing to accept the Public Staff's recommended adjustments in this proceeding, but reserves the right to litigate any of these issues with which Pluris disagrees at a later date.

On October 24, 2012, Pluris provided workpapers and invoices to the Public Staff supporting additional rate case expenses. The Public Staff audited these documents and the updated rate case expenses have been included in the Public Staff's calculation of ADIT, deferred charges, cash working capital, and operating expenses included in its Proposed Order.

As previously discussed, on October 25, 2012, Pluris filed a late-filed exhibit with the Commission updating its rate case expense up to the time of the filing of proposed orders. Also, on October 25, 2012, Pluris filed a letter with the Commission stating that the Company had reviewed the Public Staff's Proposed Order and, for the purpose of resolving the issues in this proceeding, has accepted the Public Staff's proposed adjustments and revised rates contained therein.

Based upon the foregoing, the Commission finds and concludes that the appropriate level of rate base for use in this proceeding is $8,713,424, as agreed to by the Parties for purposes of this proceeding.

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

The evidence supporting these findings of fact is contained in the application; in the testimony and exhibits of Public Staff witnesses Tweed and Henry; and in the testimony of Pluris witnesses Gallarda and Nixon.

Public Staff witness Tweed performed a billing analysis for the purpose of determining the Company's level of revenues derived from the Company's present rates and from the Company's proposed rates, as proposed in Pluris' Amended Application filed on August 24, 2012. The results of witness Tweed's analysis reflected that the end-of-period annualized revenues for the updated test year is $1,394,226, under the Company's present rates, and $3,496,739, under the Company's proposed rates as amended. Pluris did not contest these levels of total operating revenues under present and proposed rates as derived by witness Tweed.

The Commission finds and concludes that, for purposes of this proceeding, the appropriate annual level of total operating revenues for Pluris under present rates is $1,400,839, consisting of service revenues of $1,394,226 and miscellaneous revenues of $6,613 and under Pluris' amended proposed rates is $3,503,352, consisting of service revenues of $3,496,739 and miscellaneous revenues of $6,613.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 AND 13

The evidence supporting these findings of fact is contained in the testimony and exhibits of Public Staff witnesses Tweed and Henry and in the testimony of Pluris witnesses Gallarda and Nixon.

The following table summarizes the final position of the Public Staff in its Proposed Order regarding total operating expenses under present rates:

Contract services	$ 508,278
Sludge removal	41,616
Purchased power	193,029
Chemicals	63,092
Testing	25,968
Maintenance & repair	115,196
Materials & supplies	5,830
Permit fees	2,620
Alarm line expense	51,756
Vehicle expense	71,997
Management fees	205,901
Consulting fees	568
Legal fees	12,013
Accounting fees	9,400
Outside services	3,365
Other fees	201
Cleaning services	3,230
Utilities	12,763
Insurance	38,184
Miscellaneous expenses	35,351
Rate case expense	29,805
Total operating expenses	$ 1,430,163

In rebuttal testimony, witness Gallarda stated that while Pluris agrees with the vast majority of the Public Staff's recommended accounting adjustments, Pluris does not agree with all of the adjustments.

Further, witness Gallarda testified that Pluris has incurred additional rate case expenses beyond the amount calculated by the Public Staff as shown on Henry Exhibit 3-15, attached to the prefiled testimony of Public Staff witness Henry. In particular, witness Gallarda testified that Pluris will incur additional rate case expenses in preparation for the September 11, 2012 evidentiary hearing and in the preparation of its proposed order. Such costs will include additional legal fees, contract services, and travel expenses. Witness Gallarda requested permission to file a late-filed exhibit detailing the additional rate case expense incurred up to the time of the filing of the proposed orders.

On October 24, 2012, Pluris provided workpapers and invoices to the Public Staff supporting the additional rate case expenses. The Public Staff audited these documents and the updated rate case expenses have been included in the Public Staff's calculation of ADIT, deferred charges, cash working capital, and operating expenses included in its Proposed Order.

On October 25, 2012, Pluris filed a late-filed exhibit with the Commission updating its rate case expense up to the time of the filing of proposed orders. Also, on October 25, 2012, Pluris filed a letter with the Commission stating that the Company had reviewed the Public Staff's Proposed Order and, for the purpose of resolving the issues in this proceeding, has accepted the Public Staff's final proposed adjustments and revised rates contained therein.

Based upon the foregoing, the Commission finds and concludes that the appropriate level of operating expenses for use in this proceeding is $1,430,163, as agreed to by the Parties for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14 AND 15

The evidence supporting these findings of fact is contained in the testimony and exhibits of Public Staff witnesses Tweed and Henry and in the testimony of Pluris witnesses Gallarda and Nixon.

The following table summarizes the position of the Public Staff regarding depreciation expense, amortization expense - CIAC, and taxes under present rates:

Depreciation expense	$ 757,608
Amortization expense – CIAC	(469,130)
Property tax	349
Payroll tax	0
Regulatory fee	1,681
Gross receipts tax	84,050
State income tax	0
Federal income tax	0
Total depreciation, amortization, & taxes	$ 374,558

Pluris did not contest the level of total depreciation, amortization, and taxes under present rates presented by the Public Staff.

The Commission concludes that the reasonable amount of depreciation expense, amortization expense – CIAC, and taxes to include in determining ongoing rates for Pluris is $374,558, as agreed to by the Parties for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding of fact is contained in the Partial Settlement Agreement entered and filed on August 24, 2012 and in the testimony of Pluris witness Ahern and Public Staff witness Hinton.

With respect to the rate of return and capital structure, Pluris witness Ahern prefiled testimony recommending an overall rate of return of 8.57%, including a return on common equity of 12.0%, applied to a common equity ratio of 42.21%, and a long-term debt ratio of 56.53%, and customer deposits of 1.26% at December 31, 2011.

Public Staff witness Hinton recommended a capital structure consisting of 57.81% long-term debt and 42.19% common equity as of December 31, 2011. Witness Hinton testified that based upon his discounted cash flow (DCF) and risk premium analyses, he concluded that a 9.50% return on common equity was appropriate for Pluris in this proceeding.

On August 24, 2012, Pluris and the Public Staff entered and filed a Partial Settlement Agreement. The Partial Settlement Agreement contained the provision that provided the level of service being provided by Pluris in all of its service areas is found to be adequate, the components of rate of return should be as follows:

a.	Long-Term Debt Ratio:	57.81%
b.	Common Equity Ratio:	42.19%
c.	Embedded Cost of Debt:	6.12%
d.	Return on Common Equity:	9.80%
e.	Overall Weighted Rate of Return:	7.67%

Such provision also stated that Pluris and the Public Staff agreed to the following: (1) the capitalization ratios reflect an actual capital structure as of December 31, 2011 for Pluris; (2) the embedded cost of debt is Pluris' actual cost rate; and (3) the return on common equity is based upon an estimate.

Witness Hinton testified at the evidentiary hearing that the results of his DCF and risk premium analyses are fully supportive of the Partial Settlement Agreement investor return requirement on common equity of 9.80%. He further testified that in the last general rate case proceeding (Docket No. W-218, Sub 319)[1] for Aqua North Carolina, Inc. (Aqua NC), a regulated water and sewer utility, the return on common equity was a litigated issue in which the

[1] On September 13, 2011, the Commission issued a Notice of Decision and Order and on November 3, 2011, the Commission issued an Order Granting Partial Rate Increase.

Commission determined that a 10.20% return on common equity was reasonable and appropriate based upon the evidence presented in that proceeding.

The Commission finds and concludes that the provisions of the Partial Settlement Agreement between Pluris and the Public Staff, entered and filed on August 24, 2012, which is incorporated by reference herein, is just and reasonable to all parties in consideration of all the evidence presented in this proceeding and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17 AND 18

The evidence supporting these findings of fact is contained in the testimony of Public Staff witness Tweed and in the direct and rebuttal testimony of Pluris witness Gallarda.

In its application, Pluris proposed a rate structure in which residential customers with individual pump stations where the customer pays the electric expense for pumping would pay $6.22 per month less than the customer where the wastewater flows by gravity to the Company's collection system. Witness Tweed observed that a similar price difference has been included historically on Pluris' tariff and that such tariff recognizes that some customers with pump stations pay an electric bill that is not incurred by other customers who do not have an individual pump station. The Company also proposed a $5.00 per month grinder pump maintenance fee for those customers who have grinder pumps to recognize the cost of maintaining the grinder pumps where there is no such cost incurred with a gravity flow customer. Witness Tweed testified that under the Company's proposed rates the monthly flat rate for a gravity flow customer would be $1.22 higher than the rate proposed for a grinder pump customer who pays their own electric bill.

Witness Tweed testified that Pluris provides service to 559 residential simplex pump stations: (1) 476 serve one house, the customer pays the pump station electric bill and would be subject to the lower rate, and (2) 83 serve multiple residences in which Pluris, instead of the customer, pays the electric bill for the pumps. Under the Company's proposal, these 83 pump stations would also be subject to the proposed $5.00 per month grinder pump maintenance fee as well as the higher gravity customer rate because such customers do not pay their pump station electric bill. Witness Tweed testified that he does not know the number of customers served by each of the 83 pump stations and, as a result, does not know the amount of additional annual revenue that would be derived from applying the $5.00 fee to each customer. Witness Tweed recommended that no distinction be made between the residential sewer rates being paid by grinder pump customers and gravity customers, that rates be set at the same monthly flat rate and that no separate grinder pump maintenance fee be established in this proceeding.

Witness Tweed recommended that if Pluris wishes to establish a separate grinder pump maintenance fee for customers served by simplex grinder pump stations in a future proceeding, Pluris should document the average cost of providing service to the grinder pump station customers verses the gravity flow customers, and also provide data showing the average cost of electricity that the customer is paying for service to the simplex grinder pumps.

As an alternative to the proposed grinder pump maintenance fee, Pluris requested that the Public Staff consider a tariff provision that would make the customer liable if damage to the grinder pump is shown to be due to homeowner negligence. The tariff provision is similar to one in the tariff of Aqua NC applicable to its Governors Club Service Area, in Docket No. W-218, Sub 319,[1] and would read as follows:

> "Once the grinder pump is initially installed, it will be the responsibility of Pluris to maintain, repair, and replace the grinder pump. However if damage to the grinder pump is shown to be due to homeowner negligence, the homeowner will be liable for the cost of the repair or replacement of the grinder pump."

Witness Tweed testified that the Public Staff would not oppose such tariff revision provided that Pluris file a late-filed exhibit showing an enhanced grinder pump educational program for customers.

On September 19, 2012, the Company filed a late-filed exhibit which provided a draft of a proposed mailing to customers who use individual household simplex grinder sewer pump stations. In its filing, the Company presented its proposed informational material and customer letter (1) for the purpose of raising customer awareness of their responsibility for the repair and/or replacement of the grinder pump if the damage is shown to be due to homeowner negligence and (2) for promoting damage prevention practices by identifying items/materials which should not be flushed down toilets or disposed of in sink drains. On September 25, 2012, the Public Staff filed its response recommending that the Commission approve the draft grinder pump educational program provided by Pluris.

The Commission finds and concludes that it is appropriate to establish the same monthly flat rate for all residential customers in this proceeding and to approve Pluris' proposed request to insert a provision into its tariff regarding homeowner liability for damage to the grinder pumps due to homeowner negligence. If Pluris wishes to establish a separate grinder pump maintenance fee for customers served by simplex grinder pump stations in a future proceeding, Pluris should document the average cost of providing service to the grinder pump station customers verses the gravity flow customers, and also provide data showing the average cost of electricity that the customer is paying for service to the simplex grinder pumps. Further, the Commission is of the opinion that Pluris should implement its proposed educational program advising simplex grinder pump customers of items that are inappropriate to flush or to dispose of in sink drains, by mailing such informational material to each affected customer at least annually.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19 THROUGH 21

The evidence supporting these findings of fact is contained in the Company's Original and Amended Applications, the testimony of Public Staff witness Tweed, and Pluris witness Gallarda. Finding of Fact No. 19 is for informational purposes and is uncontested.

[1] On February 27, 2012, in Docket No. W-218, Sub 319, the Commission issued an Order Approving Revised Schedule of Rates and Requiring Customer Notice. An Errata Order was issued on March 2, 2012, in that same docket, to indicate that Commissioners William T. Culpepper, III, and Bryan E. Beatty did not participate in the February 27, 2012 Order.

With respect to the issue of metered residential sewer rates, 10 of the residential customers who testified at the August 9, 2012 customer hearing expressed a desire for sewer charges based upon usage rather than a monthly flat rate. Witness Tweed testified that the only feasible method of accomplishing a metered sewer rate is to obtain monthly water meter readings from the general water provider in the area, Onslow Water and Sewer Authority (ONWASA). According to witness Tweed, ONWASA currently provides water usage data to Pluris for use in billing the Company's non-residential customers for a charge of $0.50 per month per account. Witness Tweed maintained that it would require 12 months of usage data for each of the approximately 3,350 residential customers in order to make such an analysis. The Public Staff concluded that there is no residential meter reading data available in the present proceeding upon which the Commission could determine an appropriate metered sewer rate for the residential customers. Witness Tweed commented that it is not known whether ONWASA would provide water meter readings to Pluris for its approximately 3,350 residential sewer customers or whether ONWASA even provides water service to all such customers. Witness Tweed maintained that in order for the Commission to consider a metered sewer rate for these residential customers either now or in a future proceeding, Pluris would have to meet with ONWASA and obtain answers to the questions described above.

Further, witness Tweed testified that there are philosophical differences between customer groups (part-time and full-time residents, high-volume and low-volume users) and even between water and sewer providers and regulators regarding the appropriateness of metered versus flat residential sewer rates. In addition, he maintained that if metered rates are deemed appropriate, a decision must be made regarding how much of the revenue requirement should be recovered in a base monthly charge for zero usage. He pointed out that such base charge is generally intended to cover the fixed costs of the sewer operation. Witness Tweed commented that there is also a question of whether it is appropriate to place a cap on the amount of water usage that is subject to a sewer usage charge and, if so, the analysis of the 12-month test year bills to establish such a metered rate is more sophisticated.

In addition, witness Tweed observed that in Docket No. W-218, Sub 319, the last general rate case proceeding for Aqua NC, the Public Staff argued for metered residential sewer rates and Aqua NC argued for flat sewer rates. Witness Tweed testified that after thorough consideration of the many pros and cons of metered versus flat rates in that proceeding, the Commission concluded that "There is no compelling reason provided in this proceeding to deviate from the flat-rate design for residential customers now in place." The flat residential rate approved by the Commission in that proceeding was $65.07 per month.

Furthermore, witness Tweed also observed that in Docket No. W-354, Sub 327, a general rate case proceeding for Carolina Water Service, Inc. of North Carolina (CWS), CWS requested authority to increase its monthly flat sewer rate for customers in Corolla Light and Monteray Shores Service Area in Currituck County, North Carolina from approximately $40 to $136 per month. Witness Tweed commented that part of the reason for that requested increase was the cost of installing a new MBR wastewater plant. Witness Tweed explained that in that proceeding the issue of flat versus metered sewer rates was not litigated since CWS agreed to accept the Public Staff's recommendation for metered sewer rates, including a base monthly charge for zero usage of $55.54 and a usage charge of $7.06 per 1,000 gallons. Witness Tweed calculated the average monthly sewer bill to be $93.66 based upon 5,400 gallons of average monthly usage in that proceeding. Witness Tweed pointed out that CWS provided both the water and sewer service to its customers, so the availability of metered usage data was not an issue in that proceeding.

On cross-examination, witness Tweed testified that in the present proceeding there are big differences in usage between a Pluris sewer customer who is one person occupying a mobile home versus a customer who owns a large rental home. Witness Tweed contended that although the increase in the tap-on fee has helped to offset the construction cost of the new MBR Plant, it does not address the entire problem. Witness Tweed opined that the situation deserves an investigation and thorough review to determine whether metered residential sewer rates are a possibility, and if so, what the costs would be.

During cross-examination, Pluris witness Gallarda testified that he did not know whether all of Pluris' sewer customers received their water from ONWASA or if some customers have their own private wells. Witness Gallarda commented that the Company's relationship with ONWASA is "not amicable to say the least". He also pointed out that the Commission cannot compel ONWASA to do anything. Witness Gallarda testified that although he believes that the monthly flat sewer rate is the best rate methodology for Pluris at this time, that the Company would be willing to study the feasibility of metered sewer rates and file a report with the Commission detailing its findings. On cross-examination, witness Tweed stated that the Public Staff would be willing to participate in a meeting between Pluris and ONWASA, with Pluris taking the lead, to facilitate the investigation of such a study.

The Commission finds and concludes that it is appropriate to require Pluris to meet with ONWASA and report back to the Commission within 180 days of the issuance date of this Order, regarding the success or potential obstacles to obtaining sufficient data to consider the possibility of implementing metered sewer rates for all of Pluris' residential customers. The Commission observes that at the evidentiary hearing in this proceeding that the Public Staff agreed to participate in such a meeting, with Pluris taking the lead.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22 AND 23

The evidence supporting these findings of fact is contained in the testimony of Public Staff witness Tweed; in the rebuttal testimony of Pluris witness Gallarda; and in the Public Staff's Proposed Order.

The Public Staff presented its proposed annual level of service revenues and sewer rates in Tweed Exhibit No. 1, based upon the test year ended December 31, 2011, updated to June 30, 2012, including pro forma adjustments.

On October 25, 2012, Pluris filed a letter with the Commission stating that the Company had reviewed the Public Staff's Proposed Order, which reflected the Company's updated rate case expenses, and, for the purpose of resolving the issues in this proceeding, the Company has accepted the Public Staff's proposed adjustments and revised rates contained therein.

The following schedules summarize the gross revenue and return on original cost rate base that Pluris should have a reasonable opportunity to achieve based upon the increase in operating revenues approved herein. These schedules, illustrating Pluris' gross revenue requirement, incorporate the findings and conclusions found appropriate by the Commission in this Order.

Based upon the revenue requirement found reasonable in this Order, the Commission concludes that the monthly rates for sewer utility service contained in the attached Schedule of Rates are just and reasonable and should be approved.

SCHEDULE I
Pluris, LLC
Docket No. W-1282, Sub 8
Net Operating Income for a Return
For The Twelve Months Ending December 31, 2011

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$1,394,226	$1,383,123	$2,777,349
Miscellaneous revenues	6,613	0	6,613
Uncollectibles	0	0	0
Total operating revenues	1,400,839	1,383,123	2,783,962
Operating Expenses:			
Contract services	$ 508,278	0	508,278
Sludge removal	41,616	0	41,616
Purchased power	193,029	0	193,029
Chemicals	63,092	0	63,092
Testing	25,968	0	25,968
Maintenance & repair	115,196	0	115,196
Materials & supplies	5,830	0	5,830
Permit fees	2,620	0	2,620
Alarm line expense	51,756	0	51,756
Vehicle expense	71,997	0	71,997
Management fees	205,901	0	205,901
Consulting fees	568	0	568
Legal fees	12,013	0	12,013
Accounting fees	9,400	0	9,400
Outside services	3,365	0	3,365
Other fees	201	0	201
Cleaning services	3,230	0	3,230
Utilities	12,763	0	12,763
Insurance	38,184	0	38,184
Miscellaneous expenses	35,351	0	35,351
Rate case expense	29,805	0	29,805

Total operating expenses	1,430,163	0	1,430,163
Depreciation and amortization exp.	288,478	0	288,478
Property tax	349	0	349
Regulatory fee	1,681	1,660	3,341
Gross receipts tax	84,050	82,988	167,038
State income tax	0	40,456	40,456
Federal income tax	0	185,592	185,592
Total operating revenue deductions	1,804,721	310,696	2,115,417
Net operating income for return	$ (403,882)	$1,072,427	$ 668,545

SCHEDULE II
Pluris, LLC
Docket No. W-1282, Sub 8
Original Cost Rate Base
For The Twelve Months Ending December 31, 2011

Item	Amount
Plant in service	$ 25,012,348
Accumulated depreciation	(5,966,815)
CIAC	(12,015,541)
Accumulated amortization of CIAC	4,112,159
Prepaid tap-on fees	(2,507,443)
Net plant in service	8,634,708
Customer deposits	(18,120)
ADIT	(197,631)
Deferred charges	132,682
Cash working capital	178,770
Average tax accruals	(16,985)
Original cost rate base	$ 8,713,424
Rate of return:	
Present	-4.63%
Approved	7.67%

SCHEDULE III
Pluris, LLC
Docket No. W-1282, Sub 8
Statement of Capitalization and Related Costs
For The Twelve Months Ending December 31, 2011

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost or Return	Net Operating Income
	Present Rates – Original Cost Rate Base			
Long-Term Debt	57.81%	$5,037,130	6.12%	$308,272
Common Equity	42.19%	3,676,294	-19.37%	(712,154)
Total	100.00%	$8,713,424		($403,882)
	Approved Rates – Original Cost Rate Base			
Long-Term Debt	57.81%	$5,037,130	6.12%	$308,272
Common Equity	42.19%	3,676,294	9.80%	360,273
Total	100.00%	$8,713,424		$668,545

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 24 THROUGH 28

The evidence supporting these findings of fact is contained in the testimony and exhibits of Public Staff witness Henry and in the testimony of Pluris witness Gallarda.

Public Staff witness Henry testified that during the Public Staff's review of the Company's application and accounting records, he determined that the contract operators were spending time on capital projects such as installing grinder pumps for new sewer service. Witness Henry observed that the contract operators did not keep track of their time spent on capital projects such that a factor could be calculated and used to allocate a percentage of their time to plant in service along with the cost of each construction project. He stated that in the present proceeding Pluris has calculated a dollar amount for time spent on installation of grinder pumps by the contract operators, which the Public Staff removed from contract operations expense and capitalized to plant in service. Witness Henry recommended that the contract operators should keep track of their time spent on all capital projects, including grinder pump installations, so that a portion of their salaries and benefits could be appropriately capitalized to plant in service.

Witness Henry also observed that Pluris Managing Member, Maurice W. Gallarda, spends some of his time on capital projects and business development but did not keep track of his time spent working on such matters. Witness Henry stated that for the test year, the allocated portion of witness Gallarda's salary has been included in expenses and none of the salary has been capitalized to plant in service associated with these tasks. Witness Henry recommended that witness Gallarda should keep track of his time spent on capital projects and business development such that a portion of his salary and benefits could be capitalized to plant in service starting with the Company's next general rate case proceeding.

Further, witness Henry recommended that the reconciliation of the budgeted versus actual expenses incurred by Utility Partners, LLC on behalf of Pluris should be completed on a monthly basis with each expense category recorded in Pluris' general ledger using the appropriate NARUC expense account. Witness Henry also observed that during the test year, the reconciliation was prepared on an annual basis, during which time, expenses incurred in a prior year were booked as if they had occurred during the current year. Witness Henry maintained that a monthly reconciliation of budget versus actual expenses would allow the Company to record expenses in the same year in which such expenses occurred.

In regard to management fees that are allocated to Pluris from its parent company, Pluris Holdings, LLC, witness Henry testified that such allocated expenses are booked on a quarterly basis as a lump sum to the management fee expense account. Witness Henry recommended that Pluris record the allocated expenses to the appropriate general ledger account for each expense category that is billed by the parent company.

With respect to the calculation of the AFUDC for this proceeding, Witness Henry testified that Pluris did not have an overall cost rate to use from a prior general rate case proceeding to utilize in the calculation of the AFUDC on the MBR Plant. Instead, the Company used its proposed cost rate to calculate the AFUDC for this proceeding. Witness Henry recommended that in the future the Company use the overall cost rate established by the Commission in the most recent general rate case in calculating the AFUDC on long-lived capital projects.

In rebuttal testimony, witness Gallarda stated that Pluris will not challenge the Public Staff adjustments in this rate case, but reserves the right to litigate some issues with which Pluris disagrees at a later date. Witness Gallarda disagreed with the Public Staff's recommendation that future AFUDC be calculated on long-lived projects using the overall cost (interest) rate approved in this current rate case. He testified that the condition of financial markets in the future is unpredictable and treatment should be evaluated based on the conditions existing at the time of any future rate proceedings. Despite this disagreement, witness Gallarda testified that Pluris is willing to accept the Public Staff's accounting recommendations in this proceeding.

Based upon the foregoing the Commission finds and concludes that the aforementioned accounting recommendations proposed by the Public Staff are appropriate and, therefore, Pluris is hereby required to implement such accounting procedures/practices beginning at the conclusion of this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That the Partial Settlement Agreement between Pluris and the Public Staff, entered and filed on August 24, 2012, is hereby approved.

2. That Pluris is authorized to increase its rates and charges for sewer utility service in its North Topsail Beach and Sneads Ferry service areas so as to produce, based on the adjusted test year level of operations, an increase in annual service revenues of $1,383,123.

3. That the Schedule of Rates, attached as Appendix A, is hereby approved and deemed to be filed with the Commission pursuant to G.S. 62-138.

4. That the Schedule of Rates is hereby authorized to become effective for service rendered on and after the issuance date of this Order.

5. That Pluris shall immediately implement its education program for simplex grinder pump customers, and mail the educational material to each affected customer at least annually.

6. That Pluris and the Public Staff shall meet with ONWASA and shall file a report with the Commission within 180 days of the issuance date of this Order regarding its investigation with respect to obtaining sufficient data to implement metered sewer rates for all of Pluris' residential customers.

7. That Pluris shall require its contract operators to keep track of their time spent on capital projects in order to allocate a portion of their salary and benefits to the cost of each project.

8. That Pluris Holdings, LLC's Managing Member, Maurice W. Gallarda, shall keep track of his time spent on capital projects and business development so that a portion of his salary and benefits can be capitalized.

9. That Pluris shall complete the reconciliation of the budgeted versus actual expenses incurred by Utility Partners on behalf of Pluris on a monthly basis with each expense recorded in Pluris' general ledger using the appropriate NARUC expense account.

10. That Pluris shall record management fees allocated to the Company from Pluris Holdings, LLC in the appropriate NARUC expense account in Pluris' general ledger.

11. That Pluris shall use the overall cost rate established by the Commission in the most recent general rate case proceeding in calculating the AFUDC on long-lived capital projects.

12. That the Notice to Customers, attached hereto as Appendix B, shall be mailed with sufficient postage or hand delivered to all affected customers by Pluris in conjunction with the next regularly scheduled billing process after the issuance date of this Order.

13. That Pluris shall file the attached Certificate of Service, properly signed and notarized, not later than 45 days after the issuance date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the _10th_day of __December_, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

fh120712.01

APPENDIX A
PAGE 1 OF 3

SCHEDULE OF RATES

for

PLURIS, LLC

for providing sewer utility service in

ALL OF ITS SERVICE AREAS IN

Onslow County, North Carolina

Monthly Residential Flat Rate:	$62.35 per unit
Monthly Non-Residential Metered Rates:	
Base charge, zero usage	$30.35 minimum
Usage charge, per 1,000 gallons	$ 9.68
Reconnection Charge:	
If sewer service cut off by utility for good cause	Actual cost

(Customers shall be given a written estimate of the actual costs prior to disconnection. An actual invoice of the costs shall be given to the customer following disconnection.)

Connection Fee:

With a road bore or without a road bore	$3,600 per single family equivalent (SFE)

A. SFE is defined as a three-bedroom home not on the barrier island, a three-habitable room home on the barrier island, or a multi-family residence unit up to three bedrooms. An amount of $1,200 per each additional bedroom not on the barrier island and each additional habitable room on the barrier island above the SFE will be added to the base SFE connection fee. The $1,200 is calculated by dividing the SFE connection fee of $3,600 by either three bedrooms or three-habitable rooms to get to the per room fee cost. In no event shall the connection fee be less than $3,600 per connection.

APPENDIX A
PAGE 2 OF 3

Examples: The connection fee for a non-barrier island four-bedroom residence or a four-habitable-room barrier island residence is $3,600 plus $1,200 or $4,800. The connection fee for a five-bedroom non-barrier island residence or five-habitable-room barrier island residence is $3,600 plus $2,400 or $6,000.

B. The connection fee for non-residential customers shall be calculated by multiplying the connection fee by the determined number of SFEs. For SFEs non-residential customers, a SFE shall be determined by taking the design flow capacity for each non-residential customer, as set forth in Administrative Code 15A NCAC 02T .0114, and dividing that design flow capacity by 360.

Simplex Pump Station Charge:

The simplex pump station charge shall be the actual costs of labor and materials for installation of the simplex pump station and service line. This charge shall be in addition to the connection fee and any road bore charge. The installed simplex pump station shall consist of a 2460LSG, 2460LSGX Series Omnivore 2hp Simplex Grinder Package or such other equivalent as approved by Pluris. The customer may, after having received a quote from Pluris, choose to have a licensed contractor perform the installation of the simplex grinder station and service line at the customer's sole expense, provided that the installation shall be in accordance with Pluris' standards. Once the simplex grinder station and all related work is approved by Pluris, the customer shall transfer the associated permit to Pluris, and Pluris shall assume responsibility for maintenance, repair, and replacement of the grinder pump.

Simplex Grinder Pump Repair Charge:

Once the grinder pump is initially installed, it will be the responsibility of Pluris to maintain, repair, and replace the grinder pump. However if damage to the grinder pump is shown to be due to homeowner negligence, the homeowner will be liable for the cost of the repair or replacement of the grinder pump.

APPENDIX A
PAGE 3 OF 3

Road Bore Charge:

The road bore charge shall be the actual costs of labor and materials for the road boring. This charge shall be in addition to the connection fee and any simplex pump station charge. The customer may choose to have a licensed contractor perform the road bore at the customer's sole expense, provided that the road bore and all related work shall be in accordance with Pluris' standards.

The above connection fees, Simplex Pump Station Charge, and Road Bore Charge do not apply to future connections for which prepaid connection fees have been received prior to the date of this Order.

Main Extension Recovery Fee: $500 per Residential Equivalent Unit (REU) connection

A. Applies to third party developers or lot owners connecting to a 12 inch force main from NC Highway 210 along NC Highway 172 west to the Oyster Landing Subdivision and east to South Bridge at Everett Creek Subdivision.

B. Main extension recovery fee to be collected by Utility and paid to: Oyster Landing, LLC, developer of Oyster Landing Subdivision, and Southbridge at Everett's Creek, LLC, developer of South Bridge at Everett's Creek Subdivision, as reimbursement for funds advanced to the Utility for construction of the force main.

Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	
Flat Rate Customers	Shall be monthly for service in advance
Metered Customers	Shall be monthly for service in arrears
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1282, Sub 8, on this the 10th day of December, 2012.

APPENDIX B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-1282, SUB 8

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Pluris, LLC, 2100 McKinney Avenue, Suite 1550, Dallas, Texas 75201, for Authority to Increase Rates for Sewer Utility Service in All of Its Service Areas in Onslow County, North Carolina	))))	**NOTICE TO CUSTOMERS**

WATER AND SEWER – RATE INCREASE

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Pluris, LLC, to increase its rates for sewer utility service to all of its customers in the North Topsail Beach and Sneads Ferry service areas in Onslow County, North Carolina. The new approved monthly rates are as follows and are effective for service rendered on or after the date of this Notice:

SEWER SERVICE

Monthly Residential Flat Rate:	$62.35
Monthly Non-Residential Metered Rates:	
Base charge, zero usage	$30.35
Usage charge, per 1,000 gallons	$ 9.68

The Commission's Order setting forth its findings and conclusions concerning this proceeding can be viewed on the Commission's website at www.ncuc.net, under the "Docket Search" feature, utilizing Docket No. W-1282, Sub 8.

This the _10th_ day of _December, 2012

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

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-1282, Sub 8, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________, 2013.

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-1282, Sub 8.

Witness my hand and notarial seal, this the ____ day of ______________, 2013.

____
Notary Public

____
Address

(SEAL) My Commission Expires: ____________________________________
Date

DOCKET NO. W-354, SUB 331

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Carolina Water Service, Inc. of North Carolina, 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Transfer the Water and Sewer Utility Systems Serving Cabarrus Woods, Victoria Park, Bradford Park, Brookstead/Cambridge, Brookstead Meadows, Canford Commons, Reedy Creek Run/Brookstead, Turtle Rock, Avensong, Stewart's Crossing, Brawley Farms, Preserve at Kinsley Lake, Lamplighter Village East, Brookdale, Steeplechase, Britley, Windsor Chase, Williams Crossing, Williams Station, Julian Meadows, South Windsor, Southwoods, Brandywine and Forest Ridge in Cabarrus and Mecklenburg Counties, North Carolina to the City of Charlotte, which is Exempt from Commission Regulation	)	ORDER CONDITIONALLY APPROVING TRANSFER AND CANCELING FRANCHISES

BY THE COMMISSION: On March 3, 2011, Carolina Water Service, Inc. of North Carolina (CWSNC), filed an application with the Commission pursuant to G.S. 62-111(a) and G.S. 62-133, for authority to transfer to the City of Charlotte (City) the water and sewer utility systems serving the following subdivisions in Mecklenburg and Cabarrus Counties, North Carolina: Cabarrus Woods, Victoria Park, Bradford Park, Brookstead/Cambridge, Brookstead Meadows, Canford Commons, Reedy Creek Run/Brookstead, Turtle Rock, Avensong, Stewart's Crossing, Brawley Farms, Preserve at Kinsley Lake, Lamplighter Village East, Brookdale, Steeplechase, Britley, Windsor Chase, Williams Crossing, Williams Station, Julian Meadows, South Windsor, Southwoods, Brandywine and Forest Ridge (collectively referred to as the Cabarrus Woods systems) The City is exempt from Commission regulation. Upon completion of the transfer, part of the Cabarrus Woods systems will be operated by Charlotte-Mecklenburg Utilities District (CMUD), a department of the City, and part by the Town of Harrisburg.

CWSNC provided notice of the proposed transfer to customers in accordance with the Commission's orders of April 8, 2011, and May 3, 2011. No customer protests have been received.

The Public Staff requested a hearing on the question of whether and how the remaining CWSNC ratepayers should be protected from any adverse impact of the proposed transfer. CWSNC asked that Commission approval of the transfer be postponed until a decision was reached on the issue raised by the Public Staff. The Commission ordered a hearing and postponed the transfer by order of June 29, 2011. On December 23, 2011, the Commission issued its Order Determining Regulatory Treatment of Gain on Sale.

CWSNC and CMUD subsequently prepared an Amendment to Utility Systems Asset Purchase Contract (Amendment). The Amendment has been executed by CWSNC and awaits approval by the Charlotte City Council. On January 18, 2012, CWSNC and CMUD moved for tentative approval of the transfer under the terms and conditions of the amended contract.

The Amendment changes three terms from the original contract. First, it increases the purchase price to be paid by CMUD by $925,000 (to a total of $26,625,000). Second, the right of CWSNC to terminate the contract if it is not allowed to retain 100% of the gain on sale has been deleted and replaced with a right on the part of both parties to terminate the contract if the Commission approval order were to impose any "unreasonable, material condition" on the transfer. Third, CMUD must participate in an appeal to the N.C. Court of Appeals from the Commission's December 23, 2011, Order.

CMUD and CWSNC have requested that the Commission approve the transfer prior to CMUD submitting the amended contract to the Charlotte City Council for final approval. Within one day of the Charlotte City Council's vote, CMUD will notify the Commission of the outcome.

The Amendment is consistent with the Commission's December 23, 2011, Order in the sense that there is no clause that would prevent a portion of the gain on sale from being assigned to the benefit of the remaining CWSNC customers. Otherwise, according to the Public Staff, the amended contract will not alter the quality of service or the economic impact on the customers of CWSNC relative to the original contract for the sale of the Cabarrus Woods systems.

The Public Staff presented this matter at the Commission's Staff Conference on January 23, 2012. The Public Staff recommended the Commission approve the transfer, subject to approval by the Charlotte City Council without any changes in the current terms and conditions.

Customers who are transferred to the City and to the Town of Harrisburg would pay lower rates than their current CWSNC rates. CMUD's rates will decrease the average monthly water and sewer bill to $46.17 from the CWSNC average of $80.70 for 4,750 gallons (6.35 ccf) of consumption. The Town of Harrisburg rates for customers outside the city limits will decrease the average monthly water and sewer bill to $60.42 from the CWSNC average of $80.70 for 4,750 gallons (6.35 ccf) of consumption. As several witnesses indicated in the hearing on regulatory treatment of gain on sale, the quality of service for customers transferred to the City and to the Town of Harrisburg will be at least as good as the service received from CWSNC. The Commission's December 23, 2011, Order provides for a sharing of the gain on sale that will protect customers remaining with CWSNC from an adverse economic impact resulting from the sale. All parties agree that the transfer is in the public interest and should be approved under G.S. 62-111. The Commission agrees.

IT IS, THEREFORE, ORDERED as follows:

1. That the transfer of the Cabarrus Woods systems from CWSNC to the City is hereby approved, subject to approval by the Charlotte City Council without any changes to the current terms and conditions.

2. That the franchises issued to CWSNC to provide water and sewer utility service in the subdivisions served by the Cabarrus Woods systems are canceled upon transfer of the systems.

3. That CMUD shall file written notice with the Commission of the outcome of the vote of the Charlotte City Council within one business day of the Council's vote.

4. That the Commission's December 23, 2011, Order Determining Regulatory Treatment of Gain on Sale remains in effect.

5. That the Notice to Customers, attached as Appendix A, be mailed with sufficient postage or hand delivered by CWSNC to all customers affected by the transfer no later than 15 days after the date of this Order.

6. That CWSNC submit to the Commission the attached Certificate of Service properly signed and notarized not later than 30 days after the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the _23rd_ day of _January, 2012.

NORTH CAROLINA UTILITIES COMMISSION
rb012312.01 Gail L. Mount, Deputy Clerk

Chairman Edward S. Finley, Jr., and Commissioner William T. Culpepper, III, did not participate.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX A

NOTICE TO CUSTOMERS
DOCKET NO. W-354, SUB 331
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order approving the transfer from Carolina Water Service, Inc. of North Carolina (CWSNC) to the City of Charlotte (Charlotte-Mecklenburg Utilities or CMUD), which is exempt from Commission regulation, the franchises for providing water and sewer utility service in Cabarrus Woods, Victoria Park, Bradford Park, Brookstead/Cambridge, Brookstead Meadows, Canford Commons, Reedy Creek Run/Brookstead, Turtle Rock, Avensong, Stewart's Crossing, Brawley Farms, Preserve at Kinsley Lake, Lamplighter Village East, Brookdale, Steeplechase, Britley, Windsor Chase, Williams Crossing, Williams Station, Julian Meadows, South Windsor, Southwoods, Brandywine and Forest Ridge (collectively referred to as the Cabarrus Woods systems).

WATER AND SEWER – SALE/TRANSFER

CMUD plans to transfer to the Town of Harrisburg the systems that serve the following subdivisions located in Cabarrus County: Cabarrus Woods, Victoria Park, Bradford Park, Brookdale, Britley, and part of Steeplechase. The Town of Harrisburg is also exempt from Commission regulation.

Customers located in the Cabarrus County subdivisions listed above will pay Harrisburg rates, resulting in a decrease in the average monthly bill, based on 4,750 gallons (6.35 ccf) of consumption, from $80.70 under CWSNC rates to an average of $60.42 under Town of Harrisburg rates. All other customers will pay CMUD's rates, resulting in a decrease in the average monthly bill, based on 4,750 gallons (6.35 ccf) of consumption, from $80.70 under CWSNC rates to an average of $46.17 under CMUD rates.

This the _23rd_ day of _January_, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

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 331, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________, 2012.

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 331.

Witness my hand and notarial seal, this the ____ day of ______________, 2012.

____
Notary Public

____
Address

(SEAL) My Commission Expires: ______________________________________
Date

DOCKET NO. W-354, SUB 331

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Application by Carolina Water Service, Inc. of North Carolina for Authority to Transfer the Water and Sewer Utility System Serving Cabarrus Woods, Victoria Park, Bradford Park, Brookstead/Cambridge, Brookstead Meadows, Canford Commons, Reedy Creek Run/ Brookstead, Turtle Rock, Avensong, Stewart's Crossing, Brawley Farms, Preserve at Kinsley Lake, Lamplighter Village East, Brookdale, Steeplechase, Britley, Winsor Chase, Williams Crossing, Williams Station, Julian Meadows, South Windsor, Southwoods, Brandywine and Forest Ridge in Cabarrus and Mecklenburg Counties, North Carolina to the City of Charlotte	)	ORDER ON SHOW CAUSE HEARING

HEARD: Wednesday, March 14, 2012, at 7:00 p.m., in the Concord City Hall, Council Chamber, 28 Union Street, Concord, North Carolina

Monday, April 23, 2012, at 2:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Bryan E. Beatty, Presiding; and Commissioners William T. Culpepper, Ill, Susan W. Rabon, ToNola D. Brown-Bland, and Lucy T. Allen

APPEARANCES:

For Carolina Water Service, Inc. of North Carolina:

Christopher J. Ayers, Poyner Spruill LLP, Post Office Box 1801, Raleigh, North Carolina 27602

For Charlotte-Mecklenburg Utilities:

Karen Kemerait, Styers & Kemerait, PLLC, 1101 Haynes Street, Suite 101, Raleigh, North Carolina 27604

For the Using and Consuming Public:

David T. Drooz, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

For the Commission Staff:

Lemuel W. Hinton, Senior Staff Attorney, North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4325

BY THE COMMISSION: On March 3, 2011, Carolina Water Service, Inc. of North Carolina (CWS) filed an application with the Commission for authority to transfer its franchise for providing water and sewer utility service in the following subdivisions: Cabarrus Woods, Victoria Park, Bradford Park, Brookstead/Cambridge, Brookstead Meadows, Canford Commons, Reedy Creek Run/Brookstead, Turtle Rock, Avensong, Stewart's Crossing, Brawley Farms, Preserve at Kinsley Lake, Lamplighter Village East, Brookdale, Steeplechase, Britley, Windsor Chase, Williams Crossing, Williams Station, Julian Meadows, South Windsor, Southwoods, Brandywine, and Forest Ridge (collectively referred to as the Cabarrus Woods Systems) in Mecklenburg and Cabarrus Counties, North Carolina, to Charlotte-Mecklenburg Utilities (CMU), a department of the City of Charlotte, North Carolina (City), which is exempt from Commission regulation.

On April 8, 2011, the Commission issued an Order Requiring Customer Notice scheduling a public hearing on the proposed transfer. The Order required CWS to mail or deliver notice to all customers in the subdivisions included in the transfer application, specifying that the matter might be determined without public hearing if no significant protests were received subsequent to customer notice.

On April 21, 2011, CWS filed a motion to amend the customer notice to include the applicable utility rates for the Town of Harrisburg (Town) and requested an extension of time within which to provide such revised notice. In support of its motion, CWS stated that the agreement between CWS and CMU provided that CWS would transfer all utility property, equipment, and customers to CMU on the date of transfer. Upon completion of the transfer of customers from CWS to CMU, CMU intended to immediately transfer to the Town the customers in Cabarrus County located in the following subdivisions: Bradford Park, Victoria Park, Cabarrus Woods, Brookdale, Britley, and a portion of Steeplechase. The notice revision was designed to avoid customer confusion in light of CMU's intention to immediately transfer customers located in Cabarrus County to the Town following the closing of the transaction with CWS.

On May 3, 2011, the Commission issued an Order Revising Customer Notice and Granting Extension of Time requiring CWS to mail or deliver the revised notice to all affected customers by May 18, 2011.

On June 1, 2011, CWS filed a verified Certificate of Service indicating that notice was provided to all customers in the subdivisions included in the transfer application as required by the Commission's May 3, 2011 Order. No customer protests were received.

On June 29, 2011, the Commission issued an Order Postponing Transfer and Scheduling Hearing which set the matter for hearing on August 23, 2011, in Raleigh on the issue of the regulatory treatment of the gain on sale and established filing dates for testimony.

The matter was heard as scheduled on August 23, 2011. Only the expert witnesses who had prefiled written testimony presented their testimonies and exhibits to the Commission. There were no public witnesses.

On December 23, 2011, the Commission issued its Order Determining Regulatory Treatment of Gain on Sale.

On January 18, 2012, CWS and CMU filed a Joint Motion Seeking Commission Approval of Application for Transfer of Public Utility Systems to Exempt Entity. In their motion, CWS and CMU sought Commission approval of the Amendment to Utility Systems Asset Purchase Contract dated January 23, 2012, which, among other things, revised the purchase price and conditions of closing.

The Public Staff presented the Joint Motion at the Commission's Staff Conference on January 23, 2012, and recommended that the Commission approve the transfer, subject to approval by the Charlotte City Council without any changes in the terms and conditions.

On January 23, 2012, the Commission issued an Order Conditionally Approving Transfer and Canceling Franchises. The Commission's order required CWS to mail or deliver notice to affected customers by February 7, 2012.

On January 24, 2012, CMU filed written notice with the Commission that the City had approved the Amendment. CWS transferred the Cabarrus Woods Systems to CMU on January 31, 2012. CWS mailed customer notice to all affected customers and filed a certificate of service to that effect with the Commission on February 3, 2012.

On February 10, 2012, Utilities, Inc. (UI), the parent of CWS, filed a letter signed by its Chief Executive Officer, Lisa Sparrow, informing the Commission of an error in the mailing of the notice by CWS pursuant to the Commission's May 3, 2011 Order. UI stated that it inadvertently failed to mail the notice to approximately 2,437 of the 3,708 affected customers – nearly two-thirds of the customers in the subdivisions included in the transfer application.

On February 24, 2012, the Commission issued an Order Scheduling Public and Show Cause Hearings, which found probable cause that CWS failed to comply with the Commission's May 3, 2011 Order and that, as a result, a substantial number of customers were deprived of their potential right to comment upon and/or request a hearing on the proposed transfer to an entity that is exempt from Commission oversight. The Commission scheduled a public hearing for March 14, 2012, to give customers the opportunity to comment on the transfer. The Commission also scheduled a show cause hearing for April 23, 2012, to determine whether the approval of the transfer should be rescinded and/or CWS should be sanctioned for failure to comply with the May 3, 2011 Order. The Commission further ordered CWS to mail a copy of the Order by certified mail and by first class mail to all customers in the subdivisions included in the transfer application no later than 7 days after the date of the Order.

On March 24, 2012, CWS filed a certificate of service certifying that it mailed notice of the public hearing and the show cause hearing to the customers of the Cabarrus Woods Systems via first class mail and certified mail as required by the Commission's February 24, 2012 Order.

The public hearing was held as scheduled on March 14, 2012. Four witnesses testified at the public hearing, including Mark Frodge, J. Tanner, Robert Reiser, and Brendon Almond. The witnesses expressed concern that they failed to receive notice about the proposed transfer in a timely fashion and that they would not have a voice in the utility service to be provided by the Town because they live outside Town limits and cannot vote in Town elections. None of those witnesses objected to the transfer of the systems to CMU.

On April 9, 2012, CWS filed the direct testimony and exhibits of Steven M. Lubertozzi and Karen Sasic. On April 12, 2012, the Public Staff filed the direct testimony of Gina Casselberry. On April 18, 2012 CMU filed the direct testimony of Barry D. Shearin.

The show cause hearing was held as scheduled on April 23, 2012. CWS witnesses Lubertozzi and Sasic testified as a panel. Public Staff witness Casselberry presented testimony. The prefiled testimony of CMU witness Shearin was admitted into evidence by stipulation of the parties.

Based upon the foregoing, the evidence presented at the hearing, and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. By Order dated May 3, 2011, CWS was ordered by the Commission to provide notice of the proposed transfer of the Cabarrus Woods Systems to all of CWS's customers in the affected subdivisions.

2. Through its own error, CWS failed to send the required notice to approximately 2,437 customers – nearly two-thirds of the customers in the affected subdivisions.

3. UI, CWS's parent company, reported the failure to provide customer notice to the Commission immediately upon discovery of the failure and offered to contact customers and solicit feedback on its own initiative.

4. UI immediately undertook an internal examination with respect to customer notice procedures and made revisions intended to ensure that this type of oversight does not occur again.

5. The transfer continues to be in the best interest of the customers being transferred, and the transfer satisfies the requirements of G.S. 62-111.

EVIDENCE AND CONCLUSIONS

The evidence supporting the findings of fact is undisputed and is found in the testimony of CWS witnesses Lubertozzi and Sasic, CMU witness Shearin, and Public Staff witness Casselberry.

CWS witnesses Lubertozzi and Sasic testified that CWS failed to provide customer notice to approximately 2,437 customers in the Cabarrus Woods Systems as the result of an employee error. They testified that CWS became aware of this failure when it was contacted by a former customer on or about February 1, 2012, after receiving a letter from the Town referencing the transfer. They further testified that an employee who was new to the UI billing department, which handles CWS's customer notices and other mailings, erroneously used only business unit numbers to effect the mailing. The internal form requesting the customer notice included business unit numbers, but did not contain all of the customer care and billing subdivision numbers (CC&B Numbers). CC&B Numbers are used within UI's customer service system to identify geographical operational areas associated with mailing addresses and field activity dispatching.

Witness Lubertozzi testified that, in hindsight, the CC&B Numbers should have been included on the mailing request and the receiving employee should have known to use those numbers to prepare the mailing. He further testified that this case is a special situation because CWS typically does not send out customer notices to subsets of customers; customer notices related to rate cases and other orders typically are mailed system-wide, and the differences between subdivision units and billing codes do not come into play. CWS's witnesses further testified that the employee believed that notice had been mailed to all affected customers based on the business unit numbers rather than subdivision numbers; thus, she executed the certificate of service and forwarded it to be filed with the Commission.

Witness Lubertozzi testified that CWS has implemented new procedures to ensure that the oversight that occurred in this case does not occur in the future. UI has revised its customer notice request form to specifically require the company name, company number, business unit numbers and subdivision numbers. Additionally, the form now requires managerial approval and will be subject to a secondary audit process where an employee in the billing department will verify that the number of notices sent is consistent with the request form. CWS's witnesses testified that the new procedures will establish redundancy and oversight to ensure all affected customers are identified irrespective of internal company coding. UI has conducted employee training related to these new procedures.

Public Staff witness Casselberry testified that she is satisfied that the changes implemented by UI should result in notice being sent to all customers in future mailings.

Each of the parties' witnesses testified that the transfer continues to be in the best interest of the former CWS customers and that rescission would effectively punish and harm the customers of those systems.

Public Staff witness Casselberry testified that the City and the Town "have the technical, managerial and financial capacity to provide good, if not better, water and sewer service to the transfer customers." She further testified that the removal of CWS's wells from service and the use of surface water should improve the quality of water for hardness and iron/manganese. She also stated that the Public Water Supply Section of the North Carolina Department of Environment and Natural Resources favored the transfer.

Furthermore, CMU witness Shearin testified that rescission would be fraught with both practical and legal difficulties, such as, for example, the fact that the wells, lift stations, and wastewater treatment plants that previously served these systems have been demolished or taken off-line. CMU acquired several of the systems as a cost-effective way of satisfying its legal obligations to provide water and sewer service to areas annexed by the City and to provide more effective fire protection in those areas. Lastly, CMU witness Shearin noted that none of CWS's former customers have objected to the transfer of the systems.

Based on the evidence contained in the record, the Commission concludes that CWS failed to provide notice of the pending transfer to all affected customers of the Cabarrus Woods Systems pursuant to the Commission's May 3, 2011 Order. The importance of customer notice, especially in cases such as this where the matter may be decided without a public hearing in the absence of customer protest, cannot be stressed enough. Notice to customers is essential in such cases and is critical to ensuring that the Commission has all necessary information before it when making its decision. Absent proper customer notice, utility customers are unable to participate in the process. The representation that notice had been provided when, in fact, it had not is a serious breach of the Commission's trust and the customers' rights.

The Commission has sought to repair the damage done by the lapse of notice in this case by requiring CWS to provide further notice to all of its affected customers, holding the public hearing that would have been scheduled had any customers protested upon receipt of the original notice, and reconsidering its approval of the transfer. Although, perhaps, not an ideal solution, by holding the public hearing in Concord on March 14, 2012, the Commission, at least, ensured that all affected customers have been provided an opportunity to testify and be heard regarding the proposed transfer of the Cabarrus Woods Systems.

Notwithstanding the notice failure, the Commission concludes that the transfer remains in the best interests of the customers being transferred and that it satisfies the requirements of G.S. 62-111. The Commission is mindful of the concerns expressed by the customers at the public hearing, including the apprehension by some about service by the Town to customers outside of Town limits. Nonetheless, the evidence in this docket shows that monthly bills for average customer usage of water and sewer service will be lower from the Town than from CWS. The evidence also shows the quality of service from the Town will be at least as good as that provided by CWS. The same evidence pertains to service from CMU: the customers will be better served by the transfer. Rescinding the transaction at this time would pose difficult legal and operational issues considering the fact that CMU and the Town have retired or disconnected facilities that CWS would require to once again provide utility service to the Cabarrus Woods Systems. Moreover, with the annexation of certain subdivisions by the City, continued service by CWS is not even an option. The Commission, therefore, concludes that the January 23, 2012 Order Conditionally Approving Transfer and Canceling Franchises should not be rescinded.

The remaining question, then, is whether CWS should be sanctioned pursuant to G.S. 62-310 for violation of the Commission's May 3, 2011 Order Revising Customer Notice and Granting Extension of Time. Based on the evidence contained in the record, the Commission concludes that CWS's failure to provide customer notice to affected customers in compliance with the May 3, 2011 Order was due to employee error and a flaw in UI's customer notice procedures. However, the failure does not appear to have been willful or the result of disregard for Commission rules, policies or orders. UI self-reported the failure to provide customer notice immediately upon its discovery of the failure and offered to contact customers and solicit feedback on its own initiative. UI also immediately undertook an internal examination with respect to customer notice procedures and made revisions intended to ensure that this type of oversight does not occur again. UI has expressed its professional embarrassment and apologized to the Commission for the incident.

Pursuant to G.S. 62-310, a public utility which violates any of the provisions of the Public Utilities Act or refuses to conform to or obey any rule, order or regulation of the Commission shall be subject to a fine of up to $1,000 for each offense, and each day such public utility continues to violate the Act or continues to refuse to obey or perform any rule, order or regulation prescribed by the Commission shall be a separate offense. The authority to impose a fine or other sanction lies within the Commission's discretion. While the Commission believes that CWS's failure to provide customer notice pursuant to the May 3, 2011 Order was a serious failure, the Commission does not find that the failure was a willful refusal of CWS or UI to obey the Commission's order. Moreover, CWS promptly notified the Commission upon discovery of its error and undertook an internal investigation which lead to the adoption of procedural changes designed to prevent reoccurrence. The Commission also notes that none of the parties recommended that a sanction be imposed in this case. Accordingly, the Commission declines to impose any fine or sanction in this matter. The Commission notes, however, that issues involving notice do arise occasionally, and hereby reminds all utilities under its jurisdiction that compliance with the Commission's rules and orders must be strictly observed and that the failure to do so will not be tolerated.

IT IS, THEREFORE, ORDERED as follows:

1. That the Commission's January 23, 2012 Order Conditionally Approving Transfer and Canceling Franchises shall remain in effect and not be rescinded and that the Commission's approval of the transfer of the Cabarrus Woods Systems from CWS to CMU is hereby affirmed; and

2. That, based on the mitigating circumstances of this case, no sanction shall be imposed on CWS for its failure to comply with the Commission's May 3, 2011 Order requiring CWS to provide notice of the pending transfer to affected customers in the subdivisions served by the Cabarrus Woods Systems.

ISSUED BY ORDER OF THE COMMISSION.
This the _4th__ day of June, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Chairman Edward S. Finley, Jr., did not participate in this decision.

Bh060412.01

DOCKET NO. W-1000, SUB 14

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Corix Utilities (Illinois) LLC	)	ORDER APPROVING
to Indirectly Acquire the Outstanding Stock	)	ACQUISITION OF STOCK AND
of Utilities, Inc.	)	REQUIRING CUSTOMER NOTICE

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, September 25, 2012

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding, Commissioner William Culpepper, III, and Commissioner Lucy T. Allen

APPEARANCES:

For Utilities, Inc. and Corix Utilities (Illinois) LLC:

Christopher J. Ayers, Esq., PoynerSpruill, LLP, 301 Fayetteville Street, Suite 1900, Raleigh, North Carolina 27601

For Corolla Light Community Association, Inc.:

Britton Allen, Esq., Brady Allen, Esq., Allen Law Office, PLLC, 1514 Glenwood Avenue, Suite 200, Raleigh, North Carolina 27608

For the Town of Harrisburg, North Carolina:

Daniel C. Higgins, Esq., Burns, Day & Presnell, P.A., 2626 Glenwood Avenue, Suite 560, Raleigh, North Carolina 27608

For the Using and Consuming Public:

Gina C. Holt, Staff Attorney, William Grantmyre, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On April 13, 2012, Corix Utilities (Illinois) LLC (Corix or Applicant) filed an application and exhibits pursuant to G.S. 62-111(a) to acquire 100% of the membership interests of Hydro Star, LLC (Hydro Star), which through its wholly owned subsidiary, Hydro Star Holdings Corporation, owns 100% of the issued and outstanding common stock of Utilities, Inc. (UI).

On June 18, 2012, the North Carolina Utilities Commission (Commission) issued an order scheduling hearing and requiring customer notice. The hearing was scheduled for Tuesday, September 25, 2012. Separate petitions to intervene were filed by Corolla Light Community

Association, Inc., and the Town of Harrisburg, North Carolina. Said petitions were granted by orders dated August 16, 2012, and September 7, 2012, respectively.

On August 27, 2012, Corix and UI pre-filed the joint direct testimony of Steven M. Lubertozzi and Hamish Cumming. On September 10, 2012, the Public Staff filed the testimony of Katherine A. Fernald, Gina Y. Casselberry and Calvin C. Craig, III. Also on September 10, Hydro Star, Corix and the Public Staff filed a Stipulation. On September 18, 2012, the joint pre-filed rebuttal testimony of Steven M. Lubertozzi and Hamish Cumming was filed on behalf of Corix and UI.

A Stipulation was entered into between the Applicant and the Public Staff on September 10, 2012 resolving the issues between these parties. The Stipulation was presented to the Commission for its consideration. The Stipulation submitted by the Applicant and the Public Staff requested that the indirect transfer of outstanding common stock of UI be approved subject to the following provisions and conditions:

(a) All records of UI will be physically available as required by North Carolina law.

(b) Corix will comply with any Commission requirement that UI personnel familiar with the company records be reasonably available in North Carolina.

(c) Corix and/or UI will not seek recovery of losses or subsidization of non-utility subsidiaries or affiliates of Corix or UI from North Carolina customers.

(d) The officers and management of UI will have reasonable authority to commit UI, and its North Carolina regulated subsidiaries, on matters considered jurisdictional to the Commission.

(e) Corix and UI will seek Commission permission before a corporate restructuring of UI.

(f) No franchise of UI, or any of its North Carolina regulated subsidiaries, now existing or hereafter issued by the Commission under the provisions of the Public Utilities Act of North Carolina, shall be sold, assigned, pledged, or transferred, nor shall control thereof be changed through stock transfer or otherwise, or any rights thereunder leased, nor shall any merger or combination, including Corix and/or UI, affecting UI and/or any of its North Carolina regulated subsidiaries, be made through acquisition of control by stock purchase or otherwise, except after application to and written approval by the Commission.

(g) Corix and UI agree to be bound by the North Carolina law and Commission Orders and rules and regulations as they relate to UI's North Carolina regulated subsidiaries.

(h) Corix and UI will seek Commission permission before a corporate restructuring of Corix if it could have an effect on the rates or service of UI's subsidiaries in North Carolina.

(i) UI and Corix agree that any acquisition of Corix, or transfer of control of UI, through an acquisition is subject to Commission approval pursuant to North Carolina General Statute § 62-111. Any such transfer without such approval is forbidden and void.

(j) All costs of the acquisition incurred by Corix and/or UI, including compensation costs, and all direct and indirect corporate cost increases for UI, or any of its subsidiaries will be recorded to account number 426 (Miscellaneous Non Utility Expense) and shall be treated for accounting and ratemaking purposes so that they do not affect the water and sewer rates and charges of UI's subsidiaries. For purposes of this agreement, the term "corporate cost increases" is defined as costs in excess of the level that UI would have incurred using prudent business judgment had the acquisition not occurred.

(k) All costs of the 2002 merger approved by the Commission in Docket No. W-1000, Sub 9, incurred by nv Nuon and/or UI, and the 2006 merger approved by the Commission in Docket No. W-1000, Sub 11, incurred by Hydro Star and/or UI, including compensation costs, and all direct and indirect corporate cost increases for UI or any of its subsidiaries will be recorded to account number 426 (Miscellaneous Non Utility Expense) and shall be treated for accounting and ratemaking purposes so that they do not affect the water and sewer rates and charges of UI's subsidiaries. For purposes of this agreement, the term "corporate cost increases" is defined as costs in excess of the level that UI would have incurred using prudent business judgment had the merger not occurred.

(l) Corix and UI and all affiliates shall take all such actions as may be reasonably necessary and appropriate to hold North Carolina ratepayers harmless from rate increases, foregone opportunities for rate decreases, and/or any other adverse effects of the transfer.

(m) Future payments to officers for annual bonuses, incentive bonuses, long-term incentive bonuses, and any other bonuses made in relation to this acquisition will be excluded from UI's utility accounts and shall be treated for accounting and ratemaking purposes so that they do not affect the water and sewer rates and charges of UI's subsidiaries.

(n) Base salaries, compensation payments, annual bonuses, incentive bonuses, long-term incentive bonuses, any other bonuses, and any incentive compensation other than those listed in Item m above shall be subject to review and ratemaking adjustments in future rate proceedings for UI, where UI holds a Commission-issued certificate, and for its North

Carolina regulated subsidiaries (including areas included within the certificate of such subsidiaries through operation of G.S. 62-110(a)). The burden of proof on each of these issues shall be upon UI and its North Carolina regulated subsidiaries.

(o) Any acquisition adjustment that results from the acquisition will be excluded from UI's utility accounts and treated for accounting and ratemaking purposes so that it does not affect water and sewer rates and charges of UI's subsidiaries.

(p) Corix and UI and its North Carolina regulated subsidiaries shall each maintain its books and records so that its equity capital is recorded pursuant to the respective NARUC Uniform System of Accounts for Class A Water and Class A Wastewater Utilities, as revised in 1996, and all subsequent revisions.

(q) Corix shall provide UI, to the extent it holds certificates issued by the Commission, and its North Carolina regulated subsidiaries with sufficient access to equity and debt capital to enable UI and its North Carolina regulated subsidiaries to adequately fund and maintain their current and future water and wastewater systems, and otherwise meet the service needs of their customers at a reasonable cost. The timing and quantity of any capital expenditures or discrete capital infusion shall be determined by the Applicant's best judgment consistent with the requirement to maintain the current future water and wastewater systems and otherwise meet the service needs of the customers at a reasonable cost.

(r) The books and records of Corix and any other affiliated companies will be made available for inspection as required under North Carolina General Statute § 62-51.

(s) UI's North Carolina operating subsidiaries and UI, where they hold certificates from the Commission, shall comply with the requirements of G.S. 62-153 with respect to the procurement of goods or services from Corix or other affiliated or subsidiary companies or entities. Whenever UI's North Carolina operating subsidiaries and UI, where they hold certificates from the Commission, seek to recover through rates the costs of goods or services procured from Corix or other affiliated or subsidiary companies or entities, or whenever the Commission requires it, UI shall have the burden of persuasion and proof as to the reasonableness of such costs in accordance with North Carolina law.

(t) UI's operations and the operations of UI's North Carolina subsidiaries are currently generally in compliance with applicable environmental regulations. In cases where UI's and/or its North Carolina subsidiaries are involved in environmental compliance issues, UI and Corix agree to continue to cooperate with all regulatory agencies in addressing any outstanding compliance issues, to the satisfaction of the environmental regulatory agencies and the Public Staff.

(u) UI shall maintain its current North Carolina management.

(v) UI, through the appropriate operating North Carolina subsidiaries, agrees to continue to be responsive to customer inquiries regarding the adequacy of service, billing issues, and compliance issues, and to maintain customer access to compliance, billing, and other operational information.

(w) UI, through the appropriate operating North Carolina subsidiaries, will continue to take steps designed to implement and further its commitment to provide superior service to North Carolina water and sewer customers.

The matter came on for public and evidentiary hearing on September 25, 2012. Steven M. Lubertozzi and Hamish Cumming testified on behalf of the Applicant in support of the application. Katherine A. Fernald, Gina Y. Casselberry and Calvin C. Craig, III, testified on behalf of the Public Staff and in support of the Stipulation. Also testifying as public witnesses were: Vincent Roy from Carolina Trace, Perry Rivers from Huntwick Subdivision and Michael Rose from Town of Harrisburg.

At the September 25, 2012 hearing, the Applicant and Public Staff presented additional stipulations that were entered into the record as an exhibit:

1. UI and its wholly owned subsidiaries in North Carolina shall continue to honor their prior existing contracts including but not limited to:

   (a) Contract dated April 26, 1985, executed by the prior utility Mercer Environmental Corporation which includes providing water and wastewater service to Aragona Village in Onslow County, North Carolina, without charging any tap on fee or wastewater connection charges.

   (b) The agreement to provide and wastewater utility service to the Blackbeard Sailing Club, Ltd., located in or near Fairfield Harbour, Craven County, North Carolina.

2. With regard to the Oak Bluff Condominiums in Brandywine Bay, Carteret County, North Carolina, which are provided water and wastewater utility service by Carolina Water Service, Inc. of North Carolina (Carolina Water):

   (a) Carolina Water will continue to operate, maintain, and repair the water and sewer service lines at Oak Bluff Condominiums in the same manner as in the past.

   (b) Should Carolina Water desire in the future to attempt to modify the responsibility for these service lines, Carolina Water must first file with the Commission a written petition requesting approval and obtain a Commission approval order.

On November 8, 2012, the Applicant and the Public Staff filed a Joint Proposed Order of Corix Utililties (Illinois) LLC and the Public Staff Approving Acquisition of Stock and Requiring Customer Notice (Joint Proposed Order) and the Town of Harrisburg filed its brief.

On November 26, 2012, all parties to the proceeding filed a Revised Joint Proposed Order of Corix Utililties (Illinois) LLC, the Public Staff, Town of Harrisburg and Corolla Light Community Association, Inc. Approving Acquisition of Stock and Requiring Customer Notice (Revised Joint Proposed Order). In the cover letter accompanying the Revised Joint Proposed Order, Corix's counsel explained that the Revised Joint Proposed Order reflected that UI and the Town of Harrisburg had reached an agreement regarding the potential sale of the Huntwick system to the Town and that all parties had now joined in the joint proposed order.

On November 30, 2012, UI and the Town of Harrisburg jointly filed a letter (Letter of Agreement) with the Commission which indicated that UI and the Town of Harrisburg had reached an agreement to participate in good faith negotiations about the potential sale of the UI sewer system assets serving Huntwick subdivision and that UI and the Town of Harrisburg had also agreed to file progress reports with the Commission regarding the negotiations every six months, with the first report due within six months of the date of the Commission's order in this docket.

On the basis of the application, the Stipulation, the Letter of Agreement, the records of the Commission and the evidence in the record, the Commission makes the following

FINDINGS OF FACT

1. UI owns six water and/or sewer operating subsidiaries in North Carolina subject to the Commission's jurisdiction. These are: Carolina Water Service Inc. of North Carolina; CWS Systems, Inc.; Transylvania Utilities, Inc.; Carolina Trace Utilities, Inc.; Elk River Utilities, Inc.; and Bradfield Farms Water Company. These companies provide service to approximately 35,000 water customers and approximately 20,000 wastewater companies in North Carolina. UI provides water and/or sewer service through approximately 75 subsidiary operating companies in 15 states. UI's operating subsidiaries provide service to approximately 290,000 customer equivalents.

2. Corix is a Delaware limited liability company, all of the outstanding membership interests of which are held indirectly by Corix Infrastructure Inc. (CII). The principal investor in CII is British Columbia Investment Management Corporation (bcIMC). bcIMC is a Canadian investment management company whose clients include public sector pension plans, public bodies, publicly administered trust funds, and government operating funds. Following consummation of the acquisition, CII may cause Corix to merge with and into Hydro Star, thereby eliminating one of the intermediate holding companies through which Corix will hold its indirect interest in UI.

3. It is appropriate for Corix to acquire 100% of the membership interests in Hydro Star according to the Purchase and Sale Agreement between Corix and Highstar Capital Fund II, L.P. and certain of its affiliates dated February 17, 2012 submitted with the application in this docket.

4. Three public witnesses testified with respect to the proposed transaction. Two witnesses testified to their desire that UI sell the 122 customer sewer system serving the Huntwick Subdivision to the Town of Harrisburg. A third public witness from Carolina Trace expressed concerns regarding the impact the proposed transfer would have on the relationship between the utility and the community.

5. The transaction will not require any additional terms, conditions or requirements, and there will be no adverse impacts on retail customers.

6. The transaction will not have a significant direct impact on the operations of the North Carolina subsidiaries of UI and the current level of service will be maintained.

7. Corix is financially fit to indirectly acquire the outstanding stock of Utilities, Inc.

8. The transaction is justified by the public convenience and necessity.

9. The stipulations between the Applicant and the Public Staff submitted in this docket should be approved.

10. The Letter of Agreement between UI and the Town of Harrisburg should be approved.

EVIDENCE AND CONCLUSIONS BASED UPON CUSTOMER TESTIMONY AND THE LETTER OF AGREEMENT

Public witnesses, Perry Rivers from the Huntwick Subdivision and Michael Rose from the Town of Harrisburg, testified regarding their belief that UI should sell the sewer system serving 122 customers in the Huntwick Subdivision to the Town of Harrisburg. Mr. Rivers testified that the Town of Harrisburg had been trying to buy the system for approximately eight years, but had been turned down by UI. Mr. Rivers complained of leaks and problems with a pump station in the community, and testified that rates would be lower if the Town purchased the system.

Mr. Rose, the town administrator for the Town of Harrisburg, testified that the Town has been interested in providing sewer service in the Huntwick service area for years and already provides the water service. Mr. Rose stated that Huntwick was annexed into the corporate limits of the Town in 1997. Mr. Rose testified as to his concern that the sale to Corix would impair or eliminate the potential for the Town to acquire the facilities serving Huntwick.

Mr. Rose testified that based upon the average water consumption of Huntwick customers, Harrisburg's average monthly metered sewer bill for Huntwick customers would be $23.88 compared to the Carolina Water monthly flat rate of $40.14. Mr. Rose further testified that if the Huntwick system was acquired by Harrisburg, the Huntwick package wastewater treatment plant would be eliminated and Harrisburg would connect the Huntwick wastewater collection system to the Fuda Creek interceptor, owned and operated by the Water and Sewer Authority of Cabarrus County. He also testified that the citizens residing in Huntwick would be retail sewer customers of Harrisburg and would be provided the same level of service and rate structure as provided to the rest of the citizens within Harrisburg's corporate limits.

On November 30, 2012, UI and the Town of Harrisburg jointly filed a Letter of Agreement with the Commission which indicated that UI and the Town of Harrisburg had reached an agreement to participate in good faith negotiations about the potential sale of the UI sewer system assets serving Huntwick subdivision and that UI and the Town of Harrisburg had also agreed to file progress reports with the Commission regarding the negotiations every six months, with the first report due within six months of the date of the Commission's order in this docket.

The Commission has stated on a number of prior occasions that it is the Commission's policy to encourage the transfer of investor owned water and/or sewer public utilities to government owned public utilities. Therefore, the Commission, after fully considering the testimony of the parties, the record proper, and the fact that no party to this proceeding has filed an objection to the agreement between UI and the Town of Harrisburg, approves the Letter of Agreement which permits UI and the Town of Harrisburg to negotiate in good faith as to the possible sale of the Huntwick sewer system, and requires UI and the Town of Harrisburg to file progress reports with the Commission regarding the progress made in negotiations every six months, with the first report due within six months from the date of this order. The Commission further finds that such negotiations are in the public interest.

Mr. Vince Roy from Carolina Trace testified about the relationship between the Carolina Trace Homeowners Association and UI and his concern that Corix continue the practice of quarterly meetings and maintain a good relationship with the residents. Mr. Roy also stated his hope that UI and the Town of Sanford would finalize their negotiations to allow UI to purchase 100% of their water from Sanford. Mr. Lubertozzi testified that UI would continue quarterly meetings with the Carolina Trace HOA and they would maintain the good relationship between UI operations staff and the community. The Commission encourages Corix to take the necessary steps to continue positive relationships with the residents of Carolina Trace and all customers, and to complete its negotiations with the Town of Sanford.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

Based upon the foregoing, the Commission is of the opinion that Corix's request to acquire 100% of the membership interest of Hydro Star is in the public interest and is approved, that the stipulations between the Applicant and the Public Staff, and that the Letter of Agreement between the Applicant and the Town of Harrisburg should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. The application for Corix to acquire 100% of the membership interests in Hydro Star as described herein and in the application is approved upon the following conditions, and that UI and Corix are hereby ordered to comply with such conditions:

(a) All records of UI will be physically available as required by North Carolina law.

(b) Corix will comply with any Commission requirement that UI personnel familiar with the company records be reasonably available in North Carolina.

(c) Corix and/or UI will not seek recovery of losses or subsidization of non-utility subsidiaries or affiliates of Corix or UI from North Carolina customers.

(d) The officers and management of UI will have reasonable authority to commit UI, and its North Carolina regulated subsidiaries, on matters considered jurisdictional to the Commission.

(e) Corix and UI will seek Commission permission before a corporate restructuring of UI.

(f) No franchise of UI, or any of its North Carolina regulated subsidiaries, now existing or hereafter issued by the Commission under the provisions of the Public Utilities Act of North Carolina, shall be sold, assigned, pledged, or transferred, nor shall control thereof be changed through stock transfer or otherwise, or any rights thereunder leased, nor shall any merger or combination, including Corix and/or UI, affecting UI, and/or any of its North Carolina regulated subsidiaries, be made through acquisition of control by stock purchase or otherwise, except after application to and written approval by the Commission.

(g) Corix and UI agree to be bound by the North Carolina law and Commission Orders and rules and regulations as they relate to UI's North Carolina regulated subsidiaries.

(h) Corix and UI will seek Commission permission before a corporate restructuring of Corix if it could have an effect on the rates or service of UI's subsidiaries in North Carolina.

(i) UI and Corix agree that any acquisition of Corix, or transfer of control of UI, through an acquisition is subject to Commission approval pursuant to North Carolina General Statute § 62-111. Any such transfer without such approval is forbidden and void.

(j) All costs of the acquisition incurred by Corix and/or UI, including compensation costs, and all direct and indirect corporate cost increases for

UI, or any of its subsidiaries will be recorded to account number 426 (Miscellaneous Non Utility Expense) and shall be treated for accounting and ratemaking purposes so that they do not affect the water and sewer rates and charges of UI's subsidiaries. For purposes of this agreement, the term "corporate cost increases" is defined as costs in excess of the level that UI would have incurred using prudent business judgment had the acquisition not occurred.

(k) All costs of the 2002 merger approved by the Commission in Docket No. W-1000, Sub 9, incurred by nv Nuon and/or UI, and the 2006 merger approved by the Commission in Docket No. W-1000, Sub 11, incurred by Hydro Star and/or UI, including compensation costs, and all direct and indirect corporate cost increases for UI or any of its subsidiaries will be recorded to account number 426 (Miscellaneous Non Utility Expense) and shall be treated for accounting and ratemaking purposes so that they do not affect the water and sewer rates and charges of UI's subsidiaries. For purposes of this agreement, the term "corporate cost increases" is defined as costs in excess of the level that UI would have incurred using prudent business judgment had the merger not occurred.

(l) Corix and UI and all affiliates shall take all such actions as may be reasonably necessary and appropriate to hold North Carolina ratepayers harmless from rate increases, foregone opportunities for rate decreases, and/or any other adverse effects of the transfer.

(m) Future payments to officers for annual bonuses, incentive bonuses, long-term incentive bonuses, and any other bonuses made in relation to this acquisition will be excluded from UI's utility accounts and shall be treated for accounting and ratemaking purposes so that they do not affect the water and sewer rates and charges of UI's subsidiaries.

(n) Base salaries, compensation payments, annual bonuses, incentive bonuses, long-term incentive bonuses, any other bonuses, and any incentive compensation other than those listed in Item m above shall be subject to review and ratemaking adjustments in future rate proceedings for UI, where UI holds a Commission-issued certificate, and for its North Carolina regulated subsidiaries (including areas included within the certificate of such subsidiaries through operation of G.S. 62-110(a)). The burden of proof on each of these issues shall be upon UI, and its North Carolina regulated subsidiaries.

(o) Any acquisition adjustment that results from the acquisition will be excluded from UI's utility accounts and treated for accounting and ratemaking purposes so that it does not affect water and sewer rates and charges of UI's subsidiaries.

(p) UI and its North Carolina regulated subsidiaries shall each maintain its books and records so that its equity capital is recorded pursuant to the respective NARUC Uniform System of Accounts for Class A Water and Class A Wastewater Utilities, as revised in 1996, and all subsequent revisions.

(q) Corix shall provide UI, to the extent it holds certificates issued by the Commission, and its North Carolina regulated subsidiaries with sufficient access to equity and debt capital to enable UI and its North Carolina regulated subsidiaries to adequately fund and maintain their current and future water and wastewater systems, and otherwise meet the service needs of their customers at a reasonable cost. The timing and quantity of any capital expenditures or discrete capital infusion shall be determined by the Applicant's best judgment consistent with the requirement to maintain the current future water and wastewater systems and otherwise meet the service needs of the customers at a reasonable cost.

(r) The books and records of Corix and any other affiliated companies will be made available for inspection as required under North Carolina General Statute § 62-51.

(s) UI's North Carolina operating subsidiaries and UI, where they hold certificates from the Commission, shall comply with the requirements of G.S. 62-153 with respect to the procurement of goods or services from Corix or other affiliated or subsidiary companies or entities. Whenever UI's North Carolina operating subsidiaries and UI, where they hold certificates from the Commission, seek to recover through rates the costs of goods or services procured from Corix or other affiliated or subsidiary companies or entities, or whenever the Commission requires it, UI shall have the burden of persuasion and proof as to the reasonableness of such costs in accordance with North Carolina law.

(t) UI's operations and the operations of UI's North Carolina subsidiaries are currently generally in compliance with applicable environmental regulations. In cases where UI's and/or its North Carolina subsidiaries are involved in environmental compliance issues, UI and Corix agree to continue to cooperate with all regulatory agencies in addressing any outstanding compliance issues, to the satisfaction of the environmental regulatory agencies and the Public Staff.

(u) UI shall maintain its current North Carolina management.

(v) UI, through the appropriate operating North Carolina subsidiaries, agrees to continue to be responsive to customer inquiries regarding the adequacy of service, billing issues, and compliance issues, and to maintain customer access to compliance, billing, and other operational information.

(w) UI, through the appropriate operating North Carolina subsidiaries, will continue to take steps designed to implement and further its commitment to provide superior service to North Carolina water and sewer customers.

(x) UI and its wholly owned subsidiaries in North Carolina shall continue to honor their prior existing contracts including but not limited to:

(1) Contract dated April 26, 1985, executed by the prior utility Mercer Environmental Corporation which includes providing water and wastewater service to Aragona Village in Onslow County, North Carolina, without charging any tap on fee or wastewater connection charges.

(2) The agreement to provide and wastewater utility service to the Blackbeard Sailing Club, Ltd., located in or near Fairfield Harbour, Craven County, North Carolina.

(y) With regard to the Oak Bluff Condominiums in Brandywine Bay, Carteret County, North Carolina, which are provided water and wastewater utility service by Carolina Water:

(1) Carolina Water will continue to operate, maintain, and repair the water and sewer service lines at Oak Bluff Condominiums in the same manner as in the past.

(2) Should Carolina Water desire in the future to attempt to modify the responsibility for these service lines, Carolina Water must first file with the Commission a written petition requesting approval and obtain a Commission approval order.

2. That the joint Stipulation of the Applicant and the Public Staff signed and filed with the Commission on September 10, 2012 and the additional stipulations entered as an exhibit at the September 25, 2012 hearing, are hereby approved.

3. The November 30, 2012, Letter of Agreement between UI and the Town of Harrisburg is hereby approved.

4. That UI and the Town of Harrisburg shall participate in good faith negotiations concerning the possible sale of the Huntwick sewer system, and UI and Harrisburg shall file with the Commission a report concerning such negotiations every six months, with the first such report due within six months of the date of the Order approving the stock transfer in this docket.

5. That UI shall file with the Commission a pre-closing and post-closing balance sheet and any journal entries made to record the transaction and any related transactions within ninety day of closing.

6. That UI shall provide written notification to the Commission within ten days after the transfer has been completed.

7. That the Notice to Customers, attached as Appendix A, shall be mailed with sufficient postage to all customers of UI's North Carolina operating subsidiaries in the next regular billing cycle, and the Applicant shall submit to the Commission the attached Certificate of Service properly notarized within forty-five days of this Order.

ISSUED BY ORDER OF THE COMMISSION
This the _7th_ day of December, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Lh120712.01

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-1000, SUB 14

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Corix Utilities (Illinois) LLC to	)	NOTICE TO CUSTOMERS
Indirectly Acquire the Outstanding Stock of	)	OF TRANSFER
Utilities, Inc	)	

BY THE COMMISSION: Notice is given that the North Carolina Utilities Commission has approved the application of Corix Utilities (Illinois) LLC (Corix) to indirectly acquire the outstanding stock of Utilities, Inc. pursuant to a Purchase and Sale Agreement between Corix and Highstar Capital Fund II, L.P. and certain of its affiliates. Utilities, Inc. owns six water and/or sewer operating subsidiaries in North Carolina subject to the Commission's jurisdiction: Bradfield Farms Water Company, Carolina Trace Utilities, Inc., Carolina Water Service, Inc. of North Carolina, CWS Systems, Inc., Elk River Utilities, Inc. and Transylvania Utilities, Inc.

There are no changes in the current rates associated with this transfer. There are no changes in the mailing addresses or telephone numbers of the utility companies. If there are any future changes in telephone numbers or mailing addresses, customers will be notified.

ISSUED BY ORDER OF THE COMMISSION.
This the _7th_ day of December, 2012.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

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-1000, Sub 14, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________, 2012.

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-1000, Sub 14.

Witness my hand and notarial seal, this the ____ day of ______________, 2012.

____

Notary Public

____

Address

(SEAL) My Commission Expires: ______________________________________

Date

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Cardinal Extension Company, LLC -- G-39, SUB 24; Order Approving Fuel Tracker Adjustment (03/27/2012)

Frontier Natural Gas Company, LLC -- G-40,
SUB 104; Order on Annual Review of Gas Costs (04/27/2012)
SUB 107; Order Allowing Rate Changes Effective July 1, 2012 (06/25/2012)
SUB 109; Order Allowing Rate Changes Effective November 1, 2012 (10/29/2012)

Municipal Gas Authority of Georgia/City of Toccoa -- G-41,
SUB 32; Order on Annual Review of Gas Costs (01/18/2012)
SUB 35; Order on Annual Review of Gas Costs (11/16/2012)

Piedmont Natural Gas Company, Inc. -- G-9,
SUB 595; Order on Annual Review of Gas Costs (01/25/2012)
SUB 606; Order Approving Rate Changes Effective February 1, 2012 (01/31/2012)
SUB 611; Order Approving Rate Adjustments Effective April 1, 2012 (03/27/2012)
SUB 617; Order Approving Rate Adjustments Effective November 1, 2012 (10/29/2012)

NATURAL GAS -- Adjustments of Rates/Charges *(Continued)*
Public Service Co. of NC, Inc. -- G-5,
SUB 529; Order Approving Rate Changes Effective February 1, 2012 (01/31/2012)
SUB 531; Order Approving Rate Adjustments Effective April 1, 2012 (03/27/2012)
SUB 532; Order Allowing Rate Changes Effective April 1, 2012 (03/27/2012)
SUB 535; Order Approving Rate Adjustments Effective October 1, 2012 (09/25/2012)
SUB 536; Order Allow. Rate Changes Effective January 1, 2013 (12/19/2012)

NATURAL GAS -- Certificate
Summerlyn Farms, LLC -- G-60, SUB 0; Order Granting Certificate of Public Convenience and Necessity (01/06/2012); Errata Order (01/10/2012)

NATURAL GAS - Complaint
Piedmont Natural Gas Co., Inc. -- G-9, SUB 615; Order Canceling Hearing, Dismissing Complaint, and Closing Docket *(Rudolph Wood Holding Co.)* (12/04/2012)

NATURAL GAS -- Contracts/Agreements
Cardinal Extension Company, LLC -- G-39,
SUB 25; Order Allowing Agreement as Amended to Become Effective (06/11/2012)
SUB 26; Order Allowing Agreement as Amended to Become Effective (06/11/2012)
Piedmont Natural Gas Co., Inc. -- G-9,
SUB 568; Order Allowing Amendment to Contract to Become Effective (05/08/2012)
SUB 603; Order Approving Agreement (02/29/2012)
SUB 613; Order Approving Agreement (09/05/2012)
Public Service Co. of NC, Inc. -- G-5, SUB 475; Order Accepting Amendment for Filing (02/13/2012)

NATURAL GAS -- Depreciation Rates/Amortization
Cardinal Extension Company, LLC -- G-39, SUB 23; Order Accepting Depreciation Study for Compliance (01/24/2012)

NATURAL GAS -- Filings Due Per Order or Rule
Public Service Co. of NC, Inc. -- G-5,
SUBS 400A & 524; Order Approving Base Contract Between Public Service Company of North Carolina, Inc., and Scana Energy Marketing Inc. (10/16/2012)
SUB 438; Order Approving Modifications (04/24/2012)

NATURAL GAS -- Miscellaneous
Piedmont Natural Gas Co., Inc. - G-9, SUB 605; Order Approving Agreement (02/29/2012)

NATURAL GAS -- Reassignment of Service Area/Exchange
Frontier Natural Gas Company, LLC -- G-40, SUB 108; Order Authorizing Adjustment of Franchised Territories (08/14/2012)

NATURAL GAS -- Securities

Cardinal Pipeline Co., LLC – G-39, SUB 27; Order Granting Authority to Borrow Under Term Loan Agreement (06/06/2012)

Frontier Nat. Gas Co., LLC -- G-40,
SUB 105; Order Granting Conditional Approval (08/08/2012)
SUB 108; Order Authorizing Adjustment of Franchised Territories (08/14/2012)

Piedmont Natural Gas Company, Inc. -- G-9,
SUB 609; Order Granting Authority to Issue Notes (02/24/2012)
SUB 610; Order Granting Authority to Issue Senior Notes (03/13/2012)
SUB 616; Order Approving Issuance of Securities (10/29/2012)

Public Service Co. of NC, Inc. -- G-5, SUB 534; Order Granting Authority to Issue Securities (09/12/2012)

RENEWABLE ENERGY THERMAL

RENEWABLE ENERGY THERMAL -- Filings Due Per Order or Rule

ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

Orders Issued

Company	Docket No.	Date
Appalachian State University		
(Plemmons Student Union)	RET-33, SUB 0	(05/16/2012)
(Frank Hall)	RET-33, SUB 2	(05/16/2012)
(Varsity Gymnasium)	RET-33, SUB 3	(05/16/2012)
(Reich College of Education)	RET-33, SUB 4	(05/16/2012)
FLS Owner II, LLC		
(West Raleigh Hyatt Place)	RET-8, SUB 19	(02/27/2012)
(Hampton Inn)	RET-8, SUB 20	(02/27/2012)
(Cleveland County Detention Facility)	RET-8, SUB 21	(02/27/2012)
(Pitt County Detention Facility)	RET-8, SUB 22	(02/27/2012)
(McDowell County High School)	RET-8, SUB 23	(02/27/2012)
(East McDowell Junior High School)	RET-8, SUB 24	(02/27/2012)
(Haywood Community College)	RET-8, SUB 25	(02/27/2012)
(Haywood Community College)	RET-8, SUB 26	(02/27/2012)
FLS Owner III, LLC		
(Prestage Farms, Phase 1)	RET-30, SUB 0	(02/27/2012)
FLS Owner IV, LLC		
(Prestage Farms, Phase 2)	RET-32, SUB 0	(02/27/2012)

ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY *(Continued)*
Orders Issued

Company	Docket No.	Date
FLS Owner V, LLC		
(Watkins Village)	RET 29, SUB 0	(02/27/2012)
(Knox Cove)	RET-29, SUB 1	(02/27/2012)
(TT Milcon)	RET-29, SUB 2	(09/07/2012)
(Watkins Grove)	RET-29, SUB 3	(09/07/2012)
FLS Owner VII, LLC		
(Prestage Farms, Phase 3)	RET-31, SUB 0	(02/27/2012)
FLS Solar 60, LLC		
(Meadowood Garden Apartments)	RET-24, SUB 3	(03/30/2012)
Vanir Fund I Owner, LLC		
(Fulton Family YMCA)	RET-7, SUB 6	(03/29/2012)
(Davie Family YMCA)	RET-7, SUB 7	(03/29/2012)
(Yadkin Family YMCA)	RET-7, SUB 8	(03/29/2012)
(Wilkes Family YMCA)	RET-7, SUB 9	(03/29/2012)
(Stokes Family YMCA)	RET-7, SUB 10	(03/29/2012)
(William G. White, Jr. YMCA)	RET-7, SUB 11	(09/05/2012)

SPECIAL CERTIFICATE/PSP

SPECIAL CERTIFICATE/PSP - Cancellation of Certificate

ORDER CANCELING CERTIFICATE
Orders Issued

Company	Docket No.	Date
Beaufort Grocery Company	SC-1084, SUB 1	(08/06/2012)
CFL Payphones, LLC	SC-1561, SUB 1	(04/26/2012)
Coin Telephone Service	SC-1372, SUB 1	(08/07/2012)
Commercial Pay Phones, Inc.	SC-1357, SUB 2	(04/30/2012)
Conversant Technologies, Inc.	SC-1622, SUB 1	(05/02/2012)
Durham Exchange Club Industries, Inc.	SC-1421, SUB 1	(09/11/2012)
Durham Academy, Inc.	SC-1599, SUB 1	(07/10/2012)
Forsyth Memorial Hospital	SC-66, SUB 1	(10/26/2012)
FRNKJD, Inc.	SC-1629, SUB 1	(01/20/2012)
Graham Payphone Enterprises	SC-1454, SUB 1	(08/27/2012)
GLENOIT, LLC	SC-1731, SUB 1	(11/14/2012)
HSI Telecom, Inc.	SC-1770, SUB 2	(09/07/2012)
Hughes Tele-Com	SC-1697, SUB 2	(01/20/2012)

ORDER CANCELING CERTIFICATE *(Continued)*
Orders Issued

Company	Docket No.	Date
JLR Communications, Inc.	SC-1601, SUB 2	(09/07/2012)
Martin; Wayne J.	SC-616, SUB 2	(07/11/2012)
McDaniel; John E.	SC-1670, SUB 1	(04/26/2012)
Randolph Telephone Company	SC-1368, SUB 1	(08/03/2012)
Service Telephone Company	SC-1393, SUB 1	(08/07/2012)
Southeastern Telecom	SC-847, SUB 2	(04/26/2012)
Sprint; Carolina Telephone & Telegraph Co., d/b/a	SC-1249, SUB 4	(08/27/2012)
Telephone Operating Systems, Inc.	SC-1353, SUB 3	(10/10/2012)
Town of Carrboro	SC-1713, SUB 1	(01/20/2012)
Universal Telephone, Inc.	SC-1233, SUB 1	(01/20/2012)
Ulrich Payphones, LLC	SC-1813, SUB 1	(05/21/2012)

North State Telephone Company -- SC-1373, SUB 2; Order Permitting Discontinuance of Pay Telephone Service and Cancelling COCOT Certificate (06/22/2012)

SPECIAL CERTIFICATE/PSP -- Certificate
Abdo Saleh, Inc. -- SC-1809, SUB 0; Order Issuing Certificate (02/17/2012)
Ulrich Payphones, LLC -- SC-1813, SUB 0; Order Issuing Certificate (02/17/2012)

SMALL POWER PRODUCER

SMALL POWER PRODUCER – Certificate

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
Orders Issued

Company	Docket No.	Date
AM Best Farm, LLC	SP-2199, SUB 0	(12/11/2012)
Ararat Rock Solar, LLC	SP-1606, SUB 0	(04/25/2012)
	SP-1606, SUB 1	
Arndt Farm, LLC	SP-1381, SUB 0	(05/17/2012)
	SP-1381, SUB 1	
Beth Solar, LLC	SP-1939, SUB 0	(12/19/2012)
Big Boy Solar, LLC	SP-1814, SUB 0	(12/19/2012)
	SP-1814, SUB 1	
Biscoe Solar, LLC	SP-2165, SUB 0	(12/19/2012)
Bunn Level Farm, LLC	SP-1764, SUB 0	(07/31/2012)
Chadbourn Farm, LLC	SP-1767, SUB 0	(06/20/2012)
	SP-1767, SUB 1	
Charlie Solar, LLC	SP-2059, SUB 0	(12/11/2012)

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY *(Continued)*

Orders Issued

Company	Docket No.	Date
Chatham Park Solar Farm, LLC	SP-1743, SUB 0	(08/06/2012)
Daniel Farm, LLC	SP-2200, SUB 0	(12/19/2012)
Dement Farm, LLC	SP-2201, SUB 0	(12/11/2012)
Dibrell Farm, LLC	SP-1730, SUB 0	(07/31/2012)
Element Markets LFG, LLC	SP-1838, SUB 0	(10/08/2012)
ENlight Solar, LLC	SP-2065, SUB 0	(11/29/2012)
Fuquay Farm, LLC	SP-1611, SUB 0	(05/31/2012)
Garrell Solar Farm, LLC	SP-1870, SUB 0	(11/07/2012)
Haynes Farm, LLC	SP-1729, SUB 0	(06/11/2012)
Lenoir Farm, LLC	SP-1910, SUB 0	(09/26/2012)
Lenoir Farm 2, LLC	SP-1908, SUB 0	(09/26/2012)
Lotus Solar, LLC	SP-1813, SUB 0	(12/19/2012)
	SP-1813, SUB 1	
Marshville Farm, LLC	SP-1771, SUB 0	(07/31/2012)
	SP-1771, SUB 1	
McDowell Green Energy, LLC	SP-1081, SUB 0	(02/13/2012)
Mile Farm, LLC	SP-1844, SUB 0	(09/26/2012)
Milo Solar, LLC	SP-1965, SUB 0	(11/07/2012)
Minnie Solar, LLC	SP-1967, SUB 0	(11/07/2012)
Moore Solar Farm, LLC	SP-1893, SUB 0	(10/23/2012)
Moorings Farm, LLC	SP-1919, SUB 0	(11/19/2012)
Mount Olive Farm, LLC	SP-2040, SUB 0	(11/29/2012)
New Bern Farm, LLC	SP-1897, SUB 0	(10/23/2012)
Nick Solar, LLC	SP-1769, SUB 0	(08/29/2012)
Oakboro Farm, LLC	SP-2197, SUB 0	(12/19/2012)
Mocksville Farm, LLC	SP-1613, SUB 0	(05/31/2012)
Moncure Farm, LLC	SP-1633, SUB 0	(05/23/2012)
Neuse River Solar Farm II, LLC	SP-1665, SUB 0	(05/23/2012)
PCSP3 Airport, LLC	SP-1596, SUB 0	(05/08/2012)
	SP-1596, SUB 1	
Progress Solar I, LLC	SP-1604, SUB 0	(04/24/2012)
Progress Solar II, LLC	SP-1605, SUB 0	(04/10/2012)
Progress Solar III, LLC	SP-1603, SUB 0	(04/10/2012)
Railroad Farm, LLC	SP-1380, SUB 0	(05/17/2012)
	SP-1380, SUB 1	
Rock Farm, LLC	SP-1659, SUB 0	(07/03/2012)
	SP-1659, SUB 1	
Rockwell Solar, LLC	SP-2166, SUB 0	(12/19/2012)
Roper Farm, LLC	SP-2198, SUB 0	(12/11/2012)
Roxboro Farm, LLC	SP-1847, SUB 0	(09/26/2012)

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY *(Continued)*

Orders Issued

Company	Docket No.	Date
Selma Solar, LLC	SP-2167, SUB 0	(12/19/2012)
Siler Farm, LLC	SP-1632, SUB 0	(05/23/2012)
Sophie Solar, LLC	SP-2061, SUB 0	(12/11/2012)
SunEdison Origination1, LLC	SP-1667, SUB 0	(05/17/2012)
Trenton Farm 1, LLC	SP-1846, SUB 0	(07/31/2012)
	SP-1846, SUB 1	
Trenton Farm 2, LLC	SP-1765, SUB 0	(06/20/2012)
	SP-1765, SUB 1	
Turkey Branch Solar, LLC	SP-2168, SUB 0	(12/19/2012)
Two Lines Farm, LLC	SP-1721, SUB 0	(05/23/2012)
Vale Farm, LLC	SP-1635, SUB 0	(05/31/2012)
Waco Farm, LLC	SP-1614, SUB 0	(05/31/2012)
Wagstaff Farm 1, LLC	SP-2217, SUB 0	(12/19/2012)
Warrenton Farm, LLC	SP-1713, SUB 0	(05/23/2012)
White Cross Farm, LLC	SP-1621, SUB 0	(05/23/2012)
Wilson Farm I, LLC	SP-1912, SUB 0	(10/01/2012)
Yanceyville Farm, LLC	SP-1907, SUB 0	(10/23/2012)

Barnabas Investment Group, LLC -- SP-1325, SUB 0; Order Issuing Certificate and Accepting Registration as a New Renewable Energy Facility (02/13/2012)

Belwood Farm, LLC -- SP-1390, SUB 0; SP-1390, SUB 1; Order Issuing Certificate and Accepting Registration as a New Renewable Energy Facility (01/31/2012)

***Catawba; County of* --** SP-112,

SUB 2; Oder Issuing Certificate of Public Convenience and Necessity and Accepting Registration as a New Renewable Energy Facility (03/05/2012)

SUB 3; Order Issuing Certificate of Public Convenience and Necessity and Accepting Registration as a New Renewable Energy Facility (03/05/2012)

Industrial Power Generating Co., LLC -- SP-1472, SUB 0; Order Issuing Certificate and Accepting Registration as a New Renewable Energy Facility (01/24/2012)

***Plymouth Solar, LLC* --** SP-1568, SUB 0; Order Issuing Certificate of Public Convenience and Necessity and Accepting Registration as a New Renewable Energy Facility (05/17/2012)

ORDER ISSUING CERTIFICATE

Orders Issued

Company	Docket No.	Date
Apple, Inc.	SP-1642, SUB 1	(05/23/2012)
Mt. Olive Farm 2, LLC	SP-2180, SUB 0	(12/05/2012)
QVC, Inc.	SP-362, SUB 2	(12/04/2012)
Raeford Farm,	SP-1303, SUB 0	(01/05/2012)

ORDER ISSUING CERTIFICATE *(Continued)*
Orders Issued

Company	Docket No.	Date
Railroad Farm 2, LLC	SP-1918, SUB 0	(12/04/2012)
SunPower Corporation Systems	SP-2083, SUB 0	(11/07/2012)
	SP-2083, SUB 1	(11/19/2012)
Shannon Farm, LLC	SP-1304, SUB 0	(01/05/2012)
South Robeson Farm, LLC	SP-1290, SUB 0	(01/05/2012)
Washington White Post Solar, LLC	SP-2114, SUB 0	(11/07/2012)
Watts Farm, LLC	SP-1301, SUB 0	(01/05/2012)

Apple, Inc. – SP-1642, SUB 0; Order Issuing Certificate of Public Convenience and Necessity (05/17/2012)

Bradley Solar, LLC -- SP-1966, SUB 0; Order Allowing Withdrawal of Application and Closing Docket (12/21/2012)

Buster Solar, LLC -- SP-2063, SUB 0; Order Allowing Withdrawal of Application and Closing Docket (12/21/2012)

CSE II LLC -- SP-2363, SUB 0; Order Allowing Withdrawal of Application and Closing Docket (12/21/2012)

Emily Energy, LLC -- SP-1812, SUB 0; SP-1812, SUB 1; Order Allowing Withdrawal of Application and Registration and Closing Dockets (09/06/2012)

H Creek Farm, LLC -- SP-1622, SUB 0; Order Allow. Withdrawal of Application (03/29/2012)

Kinney Farm, LLC -- SP-1857, SUB 0; Order Allow. Withdrawal of Application and Closing Docket (10/09/2012)

Lincoln Fields Farm, LLC -- SP-1911, SUB 0; Order Allowing Withdrawal of Application and Closing Docket (10/09/2012)

Mack Solar, LLC -- SP-1809, SUB 0; SP-1809, SUB 1; Order Allowing Withdrawal of Application and Registration and Closing Dockets (09/06/2012)

Penny Solar, LLC -- SP-1937, SUB 0; Order Allowing Withdrawal of Application and Closing Docket (10/31/2012)

QVC, Inc. -- SP-362, SUB 2; SP-2082, SUB 0; Order Opening New Docket and Closing Existing Docket (10/16/2012)

Ridgecrest Solar, LLC -- SP-2099, SUB 0; Order Allowing Withdrawal of Application and Closing Docket (10/09/2012)

Scotland Farm, LLC -- SP-1612, SUB 0; SP-1612, SUB 1; Order Allowing Withdrawal of Applications (03/16/2012)

SECDC, LLC -- SP-2352, SUB 5; Order Allowing Withdrawal of Application and Closing Docket (12/21/2012)

Trenton Farm 2, LLC -- SP-1765, SUB 2; Order Allowing Withdrawal of Application and Closing Docket (12/21/2012)

Wayne Farm 1, LLC -- SP-1917, SUB 0; Order Allowing Withdrawal of Application and Closing Docket (10/09/2012)

ORDERS AND DECISIONS LISTED

SMALL POWER PRODUCER -- Filings Due Per Order or Rule

ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

Orders Issued

Company	Docket No.	Date
Active Concepts, LLC	SP-1447, SUB 0	(02/27/2012)
Adams, Martin and Associates PA	SP-1526, SUB 0	(04/18/2012)
ADDCO Solar Plant, LLC	SP-1519, SUB 0	(03/30/2012)
Airfield Solar Plant, LLC	SP-1577, SUB 0	(04/18/2012)
Airport Ground Solar 1, LLC	SP-1676, SUB 0	(05/14/2012)
Alamance Community College	SP-1754, SUB 0	(10/31/2012)
Appalachian State University	SP-283, SUB 3	(05/16/2012)
	SP-283, SUB 4	(10/31/2012)
	SP-283, SUB 5	(10/31/2012)
	SP-283, SUB 7	(10/31/2012)
Apple, Inc.	SP-1642, SUB 1	(12/10/2012)
Aquesta Bank	SP-203, SUB 1	(04/18/2012)
	SP-203, SUB 2	(04/18/2012)
Argand Rooftop 3, LLC	SP-1610, SUB 0	(03/07/2012)
Argand Rooftop 4, LLC	SP-1653, SUB 0	(05/08/2012)
Atlantic Corp. of Wilmington, Inc.	SP-1902, SUB 0	(09/06/2012)
B.V. Hedrick Gravel & Sand Co.	SP-1394, SUB 1	(06/05/2012)
B&K Timber, LLC	SP-1442, SUB 1	(03/07/2012)
Bamboo Stone Properties, LLC	SP-1582, SUB 1	(05/31/2012)
BECO, Inc.	SP-1143, SUB 1	(01/09/2012)
Berwald; Greg	SP-1514, SUB 0	(08/15/2012)
Beulaville Solar, LLC	SP-1922, SUB 1	(07/05/2012)
BGE Carolina Sunsense I, LLC	SP-1790, SUB 0	(06/06/2012)
Big Toe Farms, LLC	SP-1350, SUB 0	(03/07/2012)
Biltmore Energy Company, LLC	SP-1365, SUB 0	(03/07/2012)
Blue Mountain Biogas, LLC	SP-1562, SUB 0	(02/02/2012)
Bob Barker Company, Inc.	SP-2181, SUB 0	(11/30/2012)
Buffalo Ridge I LLC	SP-1942, SUB 0	(09/07/2012)
Burke; Pierre & Nancy	SP-1550, SUB 0	(05/16/2012)
C M Wilson, Inc.	SP-1487, SUB 0	(03/30/2012)
Carolina Solar Energy, LLC	SP-159, SUB 6	(07/18/2012)
Calypso Solar, LLC	SP-2042, SUB 0	(11/02/2012)
Campbell; John & Ann	SP-1169, SUB 4	(04/24/2012)
Cane Creek Solar, LLC	SP-1571, SUB 0	(04/18/2012)
CBC Alternative Energy, LLC	SP-1405, SUB 0	(03/30/2012)
Charlotte Motor Speedway Solar Plant, LLC	SP-1572, SUB 0	(04/17/2012)
Commercial Solar Applications, LLC	SP-1368, SUB 0	(05/10/2012)
Conrad Energy, LLC	SP-1396, SUB 0	(03/27/2012)

ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY *(Continued)*

Orders Issued

Company	Docket No.	Date
Crow Creek Golf Club, LLC	SP-1224, SUB 1	(02/01/2012)
Dawson; Ken	SP-1419, SUB 1	(08/15/2012)
Dunn Solar, LLC	SP-1694, SUB 0	(05/11/2012)
Eagle Electron Power Partners, Inc.	SP-1341, SUB 3	(05/10/2012)
Easton; Alvin	SP-1640, SUB 0	(06/05/2012)
Ecocorp Inc.	SP-1616, SUB 0	(04/19/2012)
Emm; Thomas A.	SP-1770, SUB 0	(09/07/2012)
Energy United Electric Membership Corp.	SP-2001, SUB 3	(11/02/2012)
	SP-2001, SUB 4	(11/02/2012)
	SP-2001, SUB 5	(11/02/2012)
Erin Solar, LLC	SP-1758, SUB 0	(05/31/2012)
ESA NC Solar, LLC	SP-1566, SUB 2	(06/06/2012)
ESA Renewables IV, LLC	SP-1565, SUB 7	(04/19/2012)
	SP-1565, SUB 9	(04/19/2012)
Exhibit Court Solar, LLC	SP-1877, SUB 0	(09/06/2012)
Farm 9081, LLC	SP-1815, SUB 0	(07/18/2012)
Farrelly; Eugene M. & Amber R.J.	SP-1538, SUB 1	(07/18/2012)
Farrington Farm, LLC	SP-1408, SUB 0	(03/30/2012)
Fibrominn, LLC	SP-1506, SUB 0	(05/15/2012)
First Citizens Bank & Trust Co.	SP-1525, SUB 0	(04/18/2012)
Flat Ridge 2 Wind Energy, LLC	SP-1984, SUB 0	(10/31/2012)
FLS Solar 60, LLC	SP-1377, SUB 0	(03/27/2012)
FLS Solar 80, LLC	SP-1646, SUB 0	(05/16/2012)
Frame; Darrell	SP-1740, SUB 1	(09/07/2012)
Franklin Solar, LLC	SP-1696, SUB 0	(05/11/2012)
Friendship Renewable Energy Project, LLC	SP-1060, SUB 1	(03/30/2012)
Gerhart; Jeff	SP-1515, SUB 0	(08/15/2012)
Grandfather Mtn. Stewardship Foundation	SP-779, SUB 0	(08/15/2012)
Grandfather Solar Project, LLC	SP-1645, SUB 0	(05/16/2012)
Great Train Robbery Solar Plant, LLC	SP-1518, SUB 0	(04/30/2012)
Green Energy Trans, LLC	SP-1153, SUB 1	(09/06/2012)
Greensboro Plumbing Supply Co.	SP-1492, SUB 0	(10/02/2012)
GWSJ, LLC	SP-1398, SUB 0	(03/27/2012)
Hessler, LLC	SP-764, SUB 2	(05/31/2012)
Highland Brewing Solar, LLC	SP-1708, SUB 0	(05/31/2012)
Hummel; Joseph & Shelly	SP-1414, SUB 0	(03/30/2012)
Information Analytics Consulting, Inc.	SP-1520, SUB 1	(05/31/2012)
Innovative Solar Systems, LLC	SP-1399, SUB 1	(05/10/2012)
Innovative Solar 2, LLC	SP-1723, SUB 1	(05/15/2012)

ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY *(Continued)*

Orders Issued

Company	Docket No.	Date
Innovative Solar 3, LLC	SP-1706, SUB 1	(05/15/2012)
Innovative Solar 4, LLC	SP-1793, SUB 1	(07/03/2012)
Innovative Solar 6, LLC	SP-1724, SUB 1	(09/06/2012)
Innovative Solar 7, LLC	SP-1725, SUB 1	(09/06/2012)
Innovative Solar 8, LLC	SP-1795, SUB 1	(07/03/2012)
Innovative Solar 9, LLC	SP-1794, SUB 1	(07/03/2012)
Jordan Hydroelectric L. P.	SP-127, SUB 4	(04/17/2012)
Jackson; James Ewell	SP-1535, SUB 0	(04/18/2012)
Jenkins; William Thomas	SP-265, SUB 1	(05/11/2012)
Jewels Realty Investment, LLC	SP-631, SUB 4	(05/31/2012)
Knight; Heath	SP-1441, SUB 1	(08/15/2012)
Kamath; Rajeev V.	SP-1580, SUB 1	(05/15/2012)
Kenansville Solar, LLC	SP-1923, SUB 1	(07/05/2012)
Kunal Thakkar, LLC	SP-629, SUB 2	(05/31/2012)
Laney Development, Inc.	SP-1619, SUB 0	(04/24/2012)
Liu; Kejun	SP-1539, SUB 1	(07/18/2012)
Lynwood Solar I, LLC	SP-1779, SUB 1	(07/26/2012)
Mahadev Enterprises, LLC	SP-1276, SUB 0	(02/27/2012)
Manway Solar, LLC	SP-1979, SUB 0	(10/31/2012)
Marshall's Locksmith Service, Inc.	SP-1553, SUB 1	(05/08/2012)
MARTIN TRUEX JR., LLC	SP-1036, SUB 1	(04/17/2012)
MB Haynes Corporation	SP-1354, SUB 0	(03/21/2012)
	SP-1354, SUB 1	(03/21/2012)
MN Energy, LLC	SP-1567, SUB 1	(05/02/2012)
Moore; Samuel B.	SP-605, SUB 1	(04/17/2012)
	SP-605, SUB 3	(11/02/2012)
Morrissey; Michael T.	SP-1383, SUB 1	(03/27/2012)
Mount Olive Solar, LLC	SP-2041, SUB 0	(11/02/2012)
Mountain Heritage Expo Center	SP-1393, SUB 1	(10/02/2012)
National Renewable Energy Corp.	SP-1452, SUB 0	(02/01/2012)
New World Renewable Energy Leasing, Inc.	SP-1039, SUB 0	(02/01/2012)
	SP-1224, SUB 0	
	SP-1039, SUB 2	(03/30/2012)
Norman R. Fortier	SP-1324, SUB 0	(03/21/2012)
North Cargo Building, LLC	SP-1623, SUB 0	(04/24/2012)
North Carolina Renewable Energy, LLC	SP-1108, SUB 4	(05/16/2012)
	SP-1108, SUB 5	(09/05/2012)
	SP-1108, SUB 6	(10/15/2012)
North Carolina Solar II, LLC	SP-1720, SUB 0	(05/31/2012)
North Kannapolis Baptist Church	SP-1490, SUB 1	(04/17/2012)
Old Beech Mountain Solar Plant, LLC	SP-1517, SUB 0	(03/30/2012)

ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY *(Continued)*

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Company	Docket No.	Date
Onslow Power Producers, LLC	SP-1841, SUB 0	(09/05/2012)
Patrick Yarn Mill, Inc.	SP-957, SUB 1	(02/27/2012)
Plummer; Nicholas	SP-2066, SUB 0	(11/02/2012)
PlutusMax, LLC	SP-1522, SUB 1	(05/31/2012)
Poole; Leslie	SP-1935, SUB 1	(10/31/2012)
Pope; John	SP-1440, SUB 1	(10/15/2012)
Price; Ronald G. & Shirley W.	SP-2000, SUB 0	(10/31/2012)
Pristine Sun Fund 3, LLC	SP-1602, SUB 0	(05/31/2012)
Quarters, LLC	SP-1666, SUB 0	(05/02/2012)
Raeford Farm, LLC	SP-1303, SUB 1	(01/09/2012)
Red Toad III, LLC	SP-1658, SUB 0	(06/05/2012)
Reily; Kevin & Katie	SP-628, SUB 2	(07/17/2012)
Rockingham; County of	SP-1249, SUB 1	(05/16/2012)
Rose Hill Solar LLC	SP-1702, SUB 0	(05/11/2012)
Rutherford; Eloise & Edmund	SP-1328, SUB 2	(08/15/2012)
R1 SOLAR	SP-1484, SUB 0	(03/30/2012)
Sandy Cross Solar, LLC	SP-1334, SUB 1	(05/10/2012)
Sanford Solar, LLC	SP-1810, SUB 0	(07/03/2012)
Seagrove Foods, Inc.	SP-1707, SUB 0	(05/15/2012)
Sefcik; Frank	SP-1131, SUB 0	(03/21/2012)
Shannon Farm, LLC	SP-1304, SUB 1	(01/09/2012)
Sheafor; Doug	SP-1397, SUB 1	(08/22/2012)
Shoe Show, Inc.	SP-1006, SUB 3	(10/15/2012)
Sietsema Farms Feeds, LLC	SP-1864, SUB 0	(09/13/2012)
Solar Specialization and Technologies, LLC	SP-1690, SUB 0	(09/05/2012)
Solar 55, LLC	SP-1899, SUB 1	(09/06/2012)
Sommerville; Mark Lee	SP-1434, SUB 1	(05/15/2012)
South Robeson Farm, LLC	SP-1290, SUB 1	(01/09/2012)
Spartanburg; Commission of Public Works of the City of	SP-1851, SUB 0	(09/21/2012)
Storms; William R.	SP-1360, SUB 0	(04/18/2012)
Sunrise NC Alexander Lessee, LLC	SP-1541, SUB 0	(02/02/2012)
Sunrise NC Daughter Lessee, LLC	SP-1536, SUB 0	(02/02/2012)
Sunrise NC Hindsman Lessee, LLC	SP-1543, SUB 0	(02/02/2012)
Sunrise NC Martin 1 Lessee, LLC	SP-1540, SUB 0	(02/02/2012)
Sunrise NC RKAN Lessee, LLC	SP-1537, SUB 0	(02/02/2012)
Sunrise NC Shields Lessee, LLC	SP-1542, SUB 0	(02/02/2012)
SunRun Solar Owner II, LLC	SP-1558, SUB 0	(04/30/2012)
Sylvester; Rick	SP-2092, SUB 0	(11/02/2012)
Tencarva Machinery Company	SP-1391, SUB 1	(02/01/2012)
The Boathouse at FSV, LLC	SP-1839, SUB 0	(09/05/2012)

ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY *(Continued)*

Orders Issued

Company	Docket No.	Date
The Rock Solar Energy Plant, LLC	SP-1652, SUB 0	(04/11/2012)
Tower Solar Farm, LLC	SP-1817, SUB 0	(07/03/2012)
Triangle Realty Investment, LLC	SP-630, SUB 4	(05/31/2012)
	SP-630, SUB 6	(05/31/2012)
Tropical Nut & Fruit Co.	SP-844, SUB 1	(04/18/2012)
Tuskegee Solar Services, LLC	SP-1761, SUB 0	(11/30/2012)
URENEW Solar, L.L.C.	SP-1757, SUB 0	(06/05/2012)
UREV Solar, LLC	SP-1378, SUB 0	(05/25/2012)
Vandewouw; Dave	SP-930, SUB 2	(05/31/2012)
W.E. Partners, IV, LLC	SP-1155, SUB 1	(10/10/2012)
Wake Technical Comm. College Foundation	SP-1595, SUB 0	(04/18/2012)
Wallace Solar, LLC	SP-1695, SUB 0	(05/11/2012)
Waller; Steven	SP-1275, SUB 2	(05/31/2012)
Warsaw Solar, LLC	SP-1741, SUB 0	(05/11/2012)
Warsaw Solar 2, LLC	SP-2043, SUB 0	(11/02/2012)
Water and Sewer Authority of Cabarrus County	SP-1768, SUB 0	(07/17/2012)
Watts Farm, LLC	SP-1301, SUB 1	(01/09/2012)
Wisniewski; Raymond	SP-1336, SUB 0	(03/21/2012)
Wright of Thomasville, Inc.	SP-1375, SUB 0	(03/27/2012)
Wyeth Holdings Corporation	SP-1326, SUB 0	(04/30/2012)
Yin Yin	SP-1521, SUB 1	(05/31/2012)
Young; Carlton Quint	SP-1971, SUB 0	(10/31/2012)
510 REPP One, LLC	SP-804, SUB 1	(08/15/2012)
2315 Atlantic Avenue Solar Facility, LLC	SP-1369, SUB 0	(03/27/2012)

Ararat Rock Solar, LLC -- SP-1606, SUB 0; SP-1606, SUB 1; Order Clarifying Registration and Closing Docket (10/02/2012)

Cane Creek Solar, LLC -- SP-1571, SUB 0; Order Amending Registration of New Renewable Energy Facility (07/26/2012)

Clifton, II; Paul K. -- SP-810, SUB; SP-810, SUB 2; Order Clarifying Amended Registration and Closing Docket (07/17/2012)

DDM Corporation -- SP-842, SUB 1; Order Amending Registration of New Renewable Energy Facility (01/24/2012)

Erin Solar, LLC -- SP-1758, SUB 0; Order Cancelling Registration and Closing Docket (09/06/2012)

ESA Renewables IV, LLC -- SP-1565, SUB 5; Order Allowing Withdrawal of Registration Application (02/16/2012)

SMALL POWER PRODUCER -- Filings Due Per Order or Rule *(Continued)*

***FLS Owner II, LLC* --** SP-1170,
SUB 1; SP-1647, SUB 0; Order Accepting Registration of New Renewable Energy Facility and Closing Docket (05/02/2012)
SUB 0; SP-1647, SUB 1; Order Amending Registration of New Renewable Energy Facility and Closing Docket (05/02/2012)

***FLS Solar 10* -** SP-341,
SUB 0; SP-639, SUB 0; Order Amending Registration of New Renewable Energy Facility and Closing Docket (09/21/2012)
SUB 1; SP-639, SUB 1; Order Amending Registration of New Renewable Energy Facility and Closing Docket (09/21/2012)

***FLS Solar 20, LLC* --** SP-1647, SUB 2; SP-1170, SUB 4; Order Accepting Registration of New Renewable Energy Facility and Closing Docket (09/13/2012)

Granville Solar, LLC -- SP-1895, SUB 1; Order Amending Certificate of Public Convenience and Necessity and Registration of New Renewable Energy Facility (10/04/2012)

Hummel; Joseph & Shelly -- SP-1414, SUB 0; Order Canceling Registration of New Renewable Energy Facility and Closing Docket (07/18/2012)

***Kazmer; Dr., Paul* --** SP-1413, SUB 0; Order Canceling Registration of New Renewable Energy Facility and Closing Docket (07/18/2012)

***JDC Manufacturing, LLC* --** SP-845, SUB 1; Order Amending Registration of New Renewable Energy Facility (01/05/2012)

***National Renewable Energy Corp.* --** SP-1452, SUB 0; Order Amending Registration of New Renewable Energy Facility (02/27/2012)

***PCIP Solar, LLC* --** SP-1251, SUB 0; SP-1251, SUB 1; SP-1489, SUB 0; Order Allowing Withdrawal of Petition to Transfer Registration Statement (04/03/2012)

Prestage Farms, Inc. -- SP-1209, SUB 0; Order Amending Registration of New Renewable Energy Facility (09/21/2012)

Shoe Show, Inc. – SP-1006, SUB 2; Order Issuing Certificate and Accepting Registration as a New Renewable Energy Facility (02/29/2012)

***SunEdison Origination1, LLC* --** SP-1667, SUB 0; SP-1667, SUB 1; SP-1895, SUB 0; SP-1895, SUB 1; Order Transferring Certificate and Accepting Registration of New Renewable Energy Facility (07/03/2012)

***W.E. Partners I, LLC* --** SP-729, SUB 1; Order Accepting Amended Registration Statement of New Renewable Energy Facility (10/10/2012)

SMALL POWER PRODUCER -- Registration Statement/Amendments

ABCZ Solar, LLC -- SP-1345, SUB 0; Order Canceling Application for Registration (01/05/2012)

Dick; Robert -- SP-1563, SUB 0; Order Allowing Withdrawal of Application (04/03/2012)

Eagle Electron Power Partners, Inc. -- SP-1341, SUB 0; SUB 4; SP-1516, SUB 0; SUB 1; SUB 2; Order Allowing Withdrawal of Applications for Registration (04/09/2012)

Ferguson; Harold – SP-1921, SUB 0; Order Withdrawing Registration of New Renewable Energy Facility and Closing Docket (09/13/2012)

FLS Owner II, LLC – SP-1170, SUB 2; Order Allow. Withdrawal of Application (03/30/2012)

FLS Owner 80, LLC -- SP-1406, SUB 0; Order Allowing Withdrawal of Application for Registration (04/09/2012)

<u>SMALL POWER PRODUCER -- Registration Statement/Amendments</u> *(Continued)*

Highland Craftsmen, Inc. -- SP-1426, SUB 1; Order Allowing Withdrawal of Registration Application (04/26/2012)

Mays; Jereme -- SP-1392, SUB 0; Order Allowing Withdrawal of Application (03/29/2012)

Packard Place Properties, LLC -- SP-1705,
SUB 0; Order Allowing Withdrawal of Application (05/08/2012)
SUB 1; Order Allowing Withdrawal of Application (05/08/2012)

Raets; Steven -- SP-1121, SUB 1; Order Allowing Withdrawal of Registration Application (02/16/2012)

Searer; Scott & Theresa -- SP-1926, SUB 0; Order Allowing Withdrawal of Registration Statement and Closing Docket (10/30/2012)

Solar Development, LLC -- SP-2024,
SUB 0; SUB 2; Order Allowing Withdrawal of Applications and Closing Dockets (11/07/2012)
SUB 1; SUB 3; Order Allowing Withdrawal of Applications and Closing Dockets (11/07/2012)

<u>SMALL POWER PRODUCER -- Report of Proposed Construction/Amendments</u>

ABCZ Solar, LLC -- SP-716, SUB 0; SUB 1; Order Clarifying Amended Registration and Closing Docket (08/22/2012)

Kruelski; Kent A. -- SP-1745, SUB 0; Order Clarifying Applicant's Filing and Closing Docket (06/14/2012)

Stogner; Mark -- SP-1655, SUB 0; Order Clarifying Applicant's Filing and Closing Docket (05/08/2012)

<u>SMALL POWER PRODUCER -- Reports</u>

Argand Energy Solutions, LLC -- SP-2051, SUB 0; Order Allowing Withdrawal of Registration Statement and Closing Docket (10/04/2012)

BGE Carolina Solar I, LLC -- SP-1449, SUB 0; SUB 1; Order Allowing Withdrawal of Applications (02/16/2012)

Lawrence Electric, Inc. -- SP-1753, SUB 0; Order Clarifying Applicant's Filing and Closing Docket (06/14/2012)

ORDERS AND DECISIONS LISTED

TELECOMMUNICATIONS

TELECOMMUNICATIONS -- Arbitration Proceeding

Time Warner Cable Information Services (North Carolina) LLC -- P-1262, SUB 5; Order Approving Composite Interconnection Agreement (08/01/2012)

TELECOMMUNICATIONS -- Cancellation of Certificate

ORDER CANCELING CERTIFICATE
Orders Issued

Company	Docket No.	Date
Abovenet Communications, Inc.	P-950, SUB 2	(11/30/2012)
American Dial Tone, Inc.	P-1509, SUB 1	(04/03/2012)
Bellerud Communications, LLC	P-1508, SUB 1	(04/03/2012)
Comvoz Communications, LLC	P-1499, SUB 1	(09/20/2012)
Cordia Communications Corp.	P-1431, SUB 1	(01/23/2012)
Gulf Long Distance, Inc.	P-499, SUB 4	(08/20/2012)
InSITE Solutions, LLC	P-1355, SUB 1	(02/08/2012)
Mebtel Long Distance Solutions, LLC	P-1170, SUB 1	(08/20/2012)
Midwesteern Telecommunications, Inc.	P-1215, SUB 3	(06/01/2012)
Triarch Marketing, Inc.	P-1506, SUB 1	(04/03/2012)
Velocity.Net Communications, Inc.	P-1447, SUB 1	(01/23/2012)

BLC Management, LLC -- P-1415, SUB 3; Order Canceling Certificates (06/01/2012)
Brydels Communications, LLC -- P-1434, SUB 2; Order Canceling Certificates (04/26/2012)
DSLnet Communications, LLC -- P-818, SUB 4; Order Canceling Certificates (02/02/2012)
Lifeconnex Telecom, LLC -- P-1439, SUB 3; Order Canceling Certificates (06/01/2012)
New Dimension Comm., Inc. -- P-1491, SUB 2; Order Canceling Certificates (04/26/2012)
Quality Telephone, Inc. -- P-1367, SUB 2; Order Canceling Certificates (06/01/2012)
Shentel Converged Services, Inc. -- P-1422, SUB 3; Order Cancelling Certificates (10/10/2012)
Zaida Communications Corp. -- P-1194, SUB 2; Order Canceling Certificates (07/05/2012)
360NETWORKS (USA), Inc. -- P-888, SUB 3; Order Cancel. Certificates (11/30/2012)

TELECOMMUNICATIONS -- Certificate

LOCAL CERTIFICATE
Orders Issued

Company	Docket No.	Date
AT&T CORP.	P-1545, SUB 1	(10/10/2012)
Celito CLEC, LLC	P-1548, SUB 0	(12/06/2012)
Common Point, LLC	P-1544, SUB 0	(09/28/2012)
Crosstel Tandem, Inc.	P-1543, SUB 0	(07/17/2012)
Liberty Bell Telecom, LLC	P-1533, SUB 0	(02/22/2012)
Momentum Telecom, Inc.	P-1154, SUB 3	(06/01/2012)

LOCAL CERTIFICATE *(Continued)*
Orders Issued

Company	Docket No.	Date
Rosebud Telephone, LLC	P-1532, SUB 0	(01/06/2012)
Sidera Networks, LLC	P-1540, SUB 1	(02/21/2012)
South Carolina Telecommunications Group Holdings, LLC	P-1546, SUB 0	(12/12/2012)
Teleport Comm. America, LLC	P-1547, SUB 1	(12/17/2012)

LONG DISTANCE CERTIFICATE
Orders Issued

Company	Docket No.	Date
Airnex Communications, Inc.	P-820, SUB 2	(11/21/2012)
AT&T Corp.	P-1545, SUB 0	(09/28/2012)
Crosstel Tandem, Inc.	P-1543, SUB 1	(07/10/2012)
Libeerty-Bell Telecom, LLC	P-1533, SUB 1	(01/06/2012)
Quad Comm, LLC	P-1534, SUB 0	(01/06/2012)
Sidera Networks, LLC	P-1540, SUB 0	(02/07/2012)
Teleport Communications America, LLC	P-1547, SUB 0	(11/21/2012)
Televergence Solutions, Inc.	P-1542, SUB 0	(12/07/2012)
Threshold Communications, Inc.	P-1539, SUB 0	(01/23/2012)
TOTAL ACCESS TELECOM INC.	P-1535, SUB 0	(01/06/2012)
1 800 Collect, Inc.	P-1537, SUB 0	(01/06/2012)

Sidera Networks, LLC -- P-1540, SUB 0; Errata Order (02/08/2012)

TELECOMMUNICATIONS -- Contracts/Agreements

ORDER APPROVING AGREEMENT(s) and/or AMENDMENT(s)
Orders Issued

Barnardsville Telephone Company -- P-75,
SUB 65 *(New Cingular Wireless PCS, LLC)* (11/19/2012)
SUB 73 *(Allied Wireless Communications Corp.)* (09/18/2012)
BellSouth Telecommunications, LLC -- P-55,
SUB 1397 *(Cellco Partnership, d/b/a Verizon Wireless)* (08/15/2012)
SUB 1526 *(T-Mobile USA, Inc.)* (10/22/2012)
SUB 1532 *(Alltel Communications, LLC, d/b/a Verizon Wireless)* (08/15/2012)
SUB 1590 *(New Cingular Wireless PCS, LLC)* (09/18/2012)
SUB 1759 *(Cricket Communications, Inc.)* (03/13/2012)
SUB 1775 (*Infotelecom, LLC)* (10/22/2012)
SUB 1849 *(Business Telecom, Inc.)* (01/20/2012)
SUB 1852 *(Capital Communications Consultants, Inc.)* (04/11/2012)
SUB 1853 *(Rosebud Telephone, LLC)* (04/11/2012)

ORDER APPROVING AGREEMENT(s) and/or AMENDMENT(s) *(Continued)*
Orders Issued

BellSouth Telecommunications, LLC -- P-55, *(Continued)*
SUB 1855 *(Fast Phones, Inc.)* (05/23/2012)
SUB 1858 *(North American Local, LLC)* (05/23/2012)
SUB 1860 *(DukeNet Communications, LLC)* (06/12/2012)
SUB 1861 *(Image Access, Inc.)* (06/12/2012)
SUB 1864 *(Linkup Telecom, Inc.)* (07/17/2012)
SUB 1865 *(Phoneaid Communications Corp.)* (07/17/2012)
SUB 1866 *(Frontier Communications of America, Inc.)* (08/15/2012)
SUB 1867 *(Absolute Home Phones, Inc.)* (08/15/2012)
SUB 1869 *(South Carolina Net, Inc., d/b/a Spirit Telecom)* (08/15/2012)
SUB 1870 *(OneTone Telecom, Inc.)* (09/18/2012)
SUB 1871 *(Safari Communications, Inc.)* (09/18/2012)
SUB 1872 *(Affordable Phone Services, Inc.)* (09/18/2012)
SUB 1878 *(New Horizons Communications, Corp.)* (12/18/2012)

Carolina Telephone and Telegraph Co & Central Telephone Co. -- P-7,
SUB 1233; P-10, SUB 850 *(QuantumShift Communications, Inc.)* (10/22/2012)
SUB 1245; P-10, SUB 861 *(Big River Telephone Company, LLC)* (10/22/2012)
SUB 1251; P-10, SUB 866 *(Qwest Communications Company, LLC)* (10/22/2012)
SUB 1252; P-10, SUB 867 *(Rosebud Telephone, LLC)* (10/22/2012)
SUB 1253; P-10, SUB 868 *(Frontier Communications of America, Inc.)* (10/23/2012)

Frontier Communications of the Carolinas, Inc. -- P-1488,
SUB 9 *(Frontier Communications of America, Inc.)* (06/12/2012)
SUB 11 *(tw telecom of north carolina l.p.)* (10/23/2012)
SUB 12 *(Spectrotel, Inc.)* (09/18/2012)
SUB 13 *(BalsamWest FiberNet, LLC)* (09/18/2012)
SUB 14 *(PNG Telecommunications, d/b/a PowerNet Global Comm.)* (09/18/2012)
SUB 15 *(NOS Communications, Inc.)* (09/18/2012)
SUB 16 *(dPi Teleconnect, LLC)* (09/18/2012)
SUB 18 *(T-Mobile South, LLC)* (10/23/2012)
SUB 19 *(Budget Prepay, Inc.)* (10/23/2012)
SUB 21 *(BullsEye Telecom, Inc.)* (11/19/2012)
SUB 22 *(Entelegent Solutions, Inc.)* (11/19/2012)
SUB 23 *(Ernest Communications, Inc.)* (11/19/2012)
SUB 24 *(iNetworks Group, Inc.)* (11/19/2012)
SUB 25 *(New Horizons Communications Corp.)* (11/19/2012)
SUB 26 *(France Telecom Corporate Solutions, LLC)* (12/18/2012)
SUB 27 *(DukeNet Communications, LLC)* (12/18/2012)

MEBTEL, Inc. -- P-35,
SUB 123 *(QuantumShift Communications, Inc.)* (10/23/2012)
SUB 124 *(Qwest Communications Company, LLC)* (10/23/2012)

ORDER APPROVING AGREEMENT(s) and/or AMENDMENT(s) *(Continued)*
Orders Issued

North State Telephone Company -- P-42,
SUB 160 *(New Cingular Wireless PCS, LLC, d/b/a AT&T Mobility)* (12/18/2012)
SUB 166 *(TCG of the Carolinas, Inc.)* (10/23/2012)
SUB 167 *(Time Warner Cable Information Services -- North Carolina, LLC)* (12/18/2012)
Pineville Telephone Company -- P-120,
SUB 20 *(New Cingular Wireless PCS, LLC)* (12/18/2012)
SUB 21 *(Sprint Spectrum L.P.)* (12/18/2012)
Saluda Mountain Telephone Co. -- P-76, SUB 55 *(New Cingular Wireless PCS)* (11/19/2012)
Service Telephone Company -- P-60, SUB 75 *(New Cingular Wireless PCS)* (11/19/2012)
Verizon South, Inc. -- P-19,
SUB 295 *(Cellco Partnership and Bell Atlantic Mobile of Asheville, Inc., d/b/a Verizon Wireless)* (09/18/2012)
SUB 302 *(BellSouth Personal Communications, Inc. (Cingular))* (09/18/2012)
SUB 305 *(Alltel Communications, Inc.)* (10/23/2012)
SUB 315 *(T-Mobile South, LLC)* (09/18/2012)
SUB 465 *(Cricket Communications, Inc.)* (12/18/2012)
SUB 512 *(Ymax Communications Corp.)* (09/18/2012)
Windstream Concord Telephone, Inc. -- P-16,
SUB 247 *(Spectrotel, Inc., d/b/a One Touch Communications, d/b/a Touch Base Communications)* (02/15/2012)
SUB 249 *(Rosebud Telephone, LLC)* (08/15/2012)
Windstream Concord Telephone, Inc. & Windstream North Carolina, LLC -- P-16,
SUB 243; P-118, SUB 174 *(Allied Wireless Communications Corp.)* (11/19/2012)
SUB 250; P-118, SUB 183 *(Broadvox-CLEC, LLC)* (12/18/2012)
SUB 251; P-118, SUB 184 *(Charter Fiberlink NC-CCO, LLC)* (12/18/2012)
Windstream North Carolina, LLC -- P-118,
SUB 179 *(tw telecom of north carolina l.p.)* (01/20/2012)
SUB 180 *(Spectrotel, Inc., d/b/a One Touch Communications, d/b/a Touch Base Communications)* (02/15/2012)
SUB 182 *(Rosebud Telephone, LLC)* (08/15/2012)
Windstream Lexcom Communications, Inc. NC. -- P-31,
SUB 153 *(Spectrotel, Inc., d/b/a One Touch Communications, d/b/a Touch Base Communications)* (02/15/2012)
SUB 154 *(Rosebud Telephone, LLC)* (08/15/2012)

TELECOMMUNICATIONS -- Discontinuance
Absolute Home Phones, Inc. -- P-1481, SUB 1; Order Granting Petition to Discontinue Service (11/19/2012)
Affordable Phone Services, Inc. -- P-1272, SUB 2; Order Granting Petition to Discontinue Service (12/11/2012)
BellSouth Telecommunications, LLC, d/b/a AT&T North Carolina -- P-55, SUB 1868; Order Authorizing Termination of Services (08/03/2012)

TELECOMMUNICATIONS -- Discontinuance *(Continued)*

Image Access, Inc., d/b/a NewPhone -- P-908, SUB 3; Order Granting Petition to Discontinue Service (06/27/2012)

Randolph Telephone Company -- P-61, SUB 102; Order Canceling Certificate and Closing Docket (02/28/2012)

TELECOMMUNICATIONS -- Miscellaneous

BellSouth Telecommunications, LLC, d/b/a AT&T North Carolina -- P-55,
SUB 1850; Order Granting Numbering Resources (01/17/2012)
SUB 1857; Order Granting Numbering Resources (06/08/2012)
SUB 1859; Order Granting Numbering Resources (04/11/2012)
SUB 1863; P-1487, SUB 1; P-100, SUB 133C; Order Authorizing Termination Subject to Conditions and Dismissing Application for Certification as An ETC (07/02/2012)
SUB 1874; Order Allowing Immediate Disconnection (08/01/2012)
SUB 1875; Order Granting Numbering Resources (09/06/2012)
SUB 1877; Order Granting Numbering Resources (10/12/2012)

Carolina Telephone and Telegraph Co., d/b/a CenturyLink -- P-7,
SUB 1246; Order Granting Numbering Resources (11/15/2012)
SUB 1248; P-10, SUB 864; Order Granting Petition (01/24/2012)
SUB 1250; Order Granting Numbering Resources (04/11/2012)

Frontier Communications of the Carolinas, Inc. -- P-1488,
SUB 7; Order Granting Numbering Resources (01/19/2012)
SUB 20; Order Granting Numbering Resources (09/19/2012)

TCG of the Carolinas, Inc. -- P-646, SUB 14; Order Grant. Numbering Resources (01/06/2012)

Windstream Communications -- P-1394, SUB 2; Order Grant. Number. Resources (06/08/2012)

TRANSPORTATION

TRANSPORTATION -- Cancellation of Certificate

ORDER CANCELING CERTIFICATE OF EXEMPTION

Orders Issued

Company	Docket No.	Date
Act of Class Relocation, Inc.	T-4178, SUB 3	(04/23/2012)
Apple Country Movers, Inc.	T-4414, SUB 1	(07/10/2012)
C & H Movers	T-4461, SUB 2	(04/23/2012)
Cli-Co Storage Corporation	T-4475, SUB 1	(11/19/2012)
Lil John Movers	T-4312, SUB 3	(03/19/2012)
Professional Moving & Storage, Inc.	T-4207, SUB 5	(09/07/2012)
Reliable Moving Co., LLC	T-4398, SUB 4	(05/25/2012)
VIP Transport Services	T-4394, SUB 4	(12/20/2012)

First Class Move -- T-4445, SUB 6; Recommended Order Canceling Certificate of Exemption (12/14/2012)

ORDERS AND DECISIONS LISTED

TRANSPORTATION -- Common Carrier Certificate

ORDER GRANTING APPLICATION FOR CERTIFICATE OF EXEMPTION
Orders Issued

Company	Docket No.	Date
Ahlgren's Transport	T-4481, SUB 0	(04/20/2012)
All Pro Packing and Moving, LLC	T-4489, SUB 0	(07/16/2012)
Appalachian Movers Transport	T-4473, SUB 0	(06/27/2012)
Beltmann Group Incorporated	T-4130, SUB 2	(01/12/2012)
Best Movers US	T-4485, SUB 0	(07/31/2012)
Cli-Co Moving	T-4505, SUB 0	(12/17/2012)
Cli-Co Storage Corporation	T-4475, SUB 0	(05/17/2012)
College Hunks Hauling Junk and Moving	T-4471, SUB 0	(01/09/2012)
Crabtree Family Moving	T-4476, SUB 0	(05/15/2012)
Dawes Moving	T-4472, SUB 0	(05/02/2012)
East Carolina Moving, LLC	T-4486, SUB 0	(08/09/2012)
Everyday Moving & Storage, LLC	T-4478, SUB 0	(07/02/2012)
Grab-N-Go Movers, LLC	T-4477, SUB 0	(05/11/2012)
Lesniak's Local Movers	T-4492, SUB 0	(11/09/2012)
Little Guys Movers, Inc.	T-4500, SUB 0	(12/11/2012)
Men on the Move, Inc.	T-4230, SUB 2	(06/19/2012)
Moving Forward Trucking, LLC	T-4468, SUB 0	(05/11/2012)
Personal Touch Movers, Inc.	T-4494, SUB 0	(10/11/2012)
Piedmont Moving	T-4470, SUB 0	(03/12/2012)
Unique Movers	T-4501, SUB 0	(11/21/2012)
3 D's Truck & Moving	T-4484, SUB 0	(09/17/2012)

Regency Moving & Storage, LLC -- T-4447, SUB 0; Order Granting Certificate of Exemption to Transport Household Goods to Regency Moving & Storage, LLC (02/03/2012)

TRANSPORTATION -- Complaint

Joyful Movers -- T-4418, SUB 1; Order Ruling Penalty Satisfied and Closing Docket (08/01/2012)

TRANSPORTATION -- Miscellaneous

Rates-Truck -- T-825, SUB 347; Order Approving Fuel Surcharge (01/04/2012); (01/31/2012); (02/28/2012); (03/20/2012); (05/15/2012); (05/30/2012); (06/12/2012); (06/26/2012); (08/07/2012); (08/21/2012); (09/11/2012); (11/06/2012)

TRANSPORTATION -- Name Change

Arpin Van Lines, Inc. -- T-4107, SUB 1; Order Approving Name Change (03/05/2012)

Appalachian Moving & Storage, LLC -- T-4383, SUB 2; Order Approving Name Change (02/22/2012)

Carolinas Office Relocation Experts **--** T-4441, SUB 1; Order Approving Name Change (06/08/2012)

States Van Lines of North Carolina, LLC -- T-4459, SUB 2; Order Approving Name Change (09/07/2012)

TRANSPORTATION -- Sale/Transfer

Keever Moving Service -- T-4479, SUB 0; T-2046, SUB 12; Order Approving Transfer and Name Change (03/06/2012)

Port City Movers, LLC -- T-4482, SUB 0; T-4249, SUB 3; Order Approving Transfer and Name Change (08/01/2012)

Two Men and A Truck of Raleigh -- T-4497, SUB 0; T-4131, SUB 2; Order Approving Transfer and Name Change (10/11/2012)

Two Men and A Truck of Winston-Salem -- T-4198, SUB 2; T-4474, SUB 0; Order Approving Transfer and Name Change (01/30/2012)

TRANSPORTATION -- Suspension

American Moving & Hauling, Inc. -- T-4323, SUB 2; Order Lifting Authorized Suspension (11/19/2012)

ASE Moving Services -- T-3245, SUB 7; Order Granting Authorized Suspension (02/17/2012); (09/07/2012)

Blue Ridge Movers, Inc. -- T-4359, SUB 2; Order Granting Authorized Suspension (02/17/2012)

Dawes Moving Service -- T-4472, SUB 1; Order Canceling Show Cause Hearing and Granting Authorized Suspension (12/20/2012)

D.R. Moving Company -- T-4462, SUB 1; Order Granting Authorized Suspension (02/17/2012)

Fleming Shaw Transfer and Storage, Inc. -- T-60, SUB 4; Order Granting Authorized Suspension (01/11/2012)

Gene Ferguson Moving Co., Inc. -- T-4243, SUB 2; Order Granting Authorized Suspension (02/17/2012)

Keever Moving Service -- T-2046, SUB 11; Order Granting Authorized Suspension (02/17/2012)

Parks Transfer -- T-4313, SUB 2; Order Granting Authorized Suspension (02/17/2012)

R. D. Helms Transfer Co. -- T-4224, SUB 3; Order Granting Authorized Suspension (10/03/2012)

ORDERS AND DECISIONS LISTED

WATER AND SEWER

WATER AND SEWER -- Bonding

Etowah Sewer Company -- W-933, SUB 8; Order Approving Bond and Surety and Releasing Bond and Surety (01/31/2012)

KDHWWTP, LLC -- W-1160, SUB 16; Order Approving Bond and Surety and Releasing Bond and Surety (12/03/2012)

Mountain Air Utilities Corp. -- W-1148,
SUB 6; Order Approv. Bond and Surety and Releasing Bond and Surety (05/01/2012)
SUB 8; Order Approv. Bond and Surety and Releasing Bond and Surety (08/06/2012)

Pluris, LLC -- W-1282, SUB 9; Order Approving Bond and Surety and Releasing Bond and Surety (09/11/2012)

Water Quality Services, Inc. -- W-1099, SUB 12; Order Approving Bond and Surety and Releasing Bond and Surety (04/10/2012)

WATER AND SEWER -- Certificate

Aqua North Carolina, Inc. -- W-218,
SUB 275; Order Granting Franchise and Approving Rates (10/15/2012)
SUB 305; Order Granting Franchise and Approving Rates (10/15/2012)

JACABB Utilities, LLC -- W-1298, SUB 0; Order Granting Franchise, Approving Rates, and Requiring Customer Notice (05/02/2012)

Water Resources, Inc. -- W-1034, SUB 6; Order Granting Motion to Collect Temporary Rates (02/22/2012)

WATER AND SEWER -- Complaint

Aqua North Carolina, Inc. -- W-218, SUB 334; Order Dismissing Complaint and Closing Docket *(Barry & Patricia Price)* (05/18/2012)

WATER AND SEWER -- Contiguous Water Extension

Aqua North Carolina, Inc. -- W-218,
SUB 231; Order Recognizing Contiguous Extension and Approving Rates (04/30/2012)
SUB 236; Order Recognizing Contiguous Extension and Approving Rates (04/30/2012)
SUB 343; Order Recognizing Contiguous Extension and Approving Rates (10/15/2012)
SUB 344; Order Granting Franchise and Approving Rates (10/15/2012)

Meadowlands Development, LLC -- W-1259, SUB 3; Order Recognizing Contiguous Extension and Approving Rates (04/27/2012)

Pine Island-Currituck, LLC -- W-1072, SUB 14; Order Recognizing Contiguous Extension (02/28/2012)

WATER AND SEWER -- Emergency Operator

Environmental Maintenance Systems, Inc. -- W-1054,
SUB 9; Order Canceling Franchise and Discharging Emergency Operator (02/08/2012)
SUB 12; Order Canceling Franchise and Discharging Emergency Operator (10/15/2012)

Hawk Run Development of Ashville, Inc. -- W-1238, SUB 4; SUB 7; SUB 8; Order Terminating Emergency Operatorship and Canceling Franchise (02/21/2012)

WATER AND SEWER -- Miscellaneous

Aqua North Carolina, Inc. -- W-218,
SUB 332; W-787, SUB 26; Order Approving Tariff Revision (02/21/2012)
SUB 333; Order Approving Company-Wide Wastewater Rule (02/21/2012)

WATER AND SEWER -- Rate Increase

Asheville Property Mgmt., Inc. -- W-1145, SUB 16; Order Granting Partial Rate Increase and Requiring Customer Notice (06/25/2012)
Christmount Christian Assembly, Inc. -- W-1079, SUB 11; Order Granting Adjustments in Rates and Requiring Customer Notice (03/27/2012)
Clarke Utilities, LLC -- W-1205, SUB 5; Order Canceling Hearing, Granting Partial Rate Increase, and Requiring Customer Notice (12/19/2012)
JACTAW Properties, LLC -- W-1209, SUB 6; Order Granting Partial Rate Increase and Requiring Customer Notice (06/25/2012)
Piedmont Water & Sewer, LLC -- W-1294, SUB 2; Recommended Order Approving Partial Rate Increase and Requiring Customer Notice (03/21/2012)
Royal Palms Water and Sewer System -- W-1105, SUB 2; Order Canceling Hearing, Granting Rate Increase, and Requiring Customer Notice (02/13/2012)
Transylvania Utilities, Inc. -- W-1012, SUB 13; Order Cancelling Hearings, Permitting Withdrawal of Application, and Closing Docket (10/30/2012); Errata Order (10/30/12)
Town & Country Mobile Home Park -- W-1193, SUB 7; Order Granting Partial Rate Increase and Requiring Customer Notice (06/25/2012)

WATER AND SEWER -- Sale/Transfer

Aqua North Carolina, Inc. -- W-218,
SUB 335; W-959, SUB 4; Recommended Order Approv. Transfer, Grant. Franchise, Approv. Rates, and Requiring Customer Notice (08/06/2012); Recommend. Order Releasing Bond and Surety to Fox Run Water Co., Inc. (10/10/2012)
SUB 336; W-1035, SUB 11; Order Approv. Transfer, Rates, and Rate Base Treatment, and Requiring Customer Notice (05/01/2012)
Bradfield Farms Water Co. -- W-1044, SUB 18; Order Approv. Transfer, Canceling Franchise, and Requiring Customer Notice (04/27/2012)
Dry Ridge Properties, LLC -- W-1299, SUB 0; W-1284, SUB 2; Order Approving Transfer of Franchise, Approving Bond, Releasing Bond, Approving Rates, and Requiring Customer Notice (02/01/2012)
Meadowlands Development, LLC -- W-1259, SUB 2; W-1287, SUB 0; Order Closing Dockets (03/27/2012)
YES AF Utilities EXP, LLC -- W-1302, SUB 0; W-1252, SUB 1; Recommended Order Approving Transfer, Granting Franchise, Approving Rates and Requiring Customer Notice (08/01/2012); Order Allowing Recommended Order to Become Effective and Final (08/01/2012)

WATER AND SEWER -- Tariff Revision for Pass-Through

ORDER APPROVING TARIFF REVISION
Orders Issued

Company	Docket No.	Date
Aqua North Carolina, Inc.		
(Crestwood, Lancer Acres & Beard Acres Subdivision)	W-218, SUB 338	(06/01/2012)
(31 Subdivisions in Johnston County)	W-218, SUB 339	(07/10/2012)
(14 Subdivisions in Cumberland Co.)	W-218, SUB 340	(06/01/2012)
(Woodland Run Subdivision)	W-218, SUB 342	(07/10/2012)
(Park South & Parkway Crossing Subdiv.)	W-218, SUB 345	(09/04/2012)
Christmount Christian Assembly, Inc.		
(Buncombe County)	W-1079, SUB 12	(08/27/2012)
Chatham Utilities, Inc.		
(Chatham Estates MH Community)	W-1240, SUB 8	(08/06/2012)
MECO Utilities, Inc.		
(Mobile Estates Mobile Home Park)	W-1166, SUB 10	(09/10/2012)
Mayfaire 1, LLC		
(Mayfaire Town Center & Mayfaire Community Center)	W-1249, SUB 6	(08/27/2012)
Mount Tabor Place Phase II, LLC		
(Mount Tabor Place Shopping Center)	W-1283, SUB 1	(04/27/2012)
Pine Island-Currituck LLC		
(Currituck County)	W-1072, SUB 15	(06/11/2012)

Joyceton Water Works, Inc. -- W-4, SUB 15; Order Approving Tariff Revision and Requiring Customer Notice (06/26/2012)

Watercrest Estates -- W-1021, SUB 8; Order Approving Tariff Revision and Requiring Customer Notice (07/17/2012)

ORDERS AND DECISIONS LISTED

RESALE OF WATER AND SEWER

RESALE OF WATER AND SEWER -- Cancellation of Certificate

ORDER CANCELING CERTIFICATE OF AUTHORITY

Orders Issued

Company	Docket No.	Date
Amelia Village, LLC		
(Amelia Village Apts.)	WR-44, SUB 3	(02/20/2012)
Asheville Eastwood Apts., LLC		
(Eastwood Village Apts.)	WR-602, SUB 5	(09/07/2012)
BBR/Paces Village, LLC		
(Paces Village Apts.)	WR-617, SUB 7	(07/05/2012)
BBR/Summerlyn, LLC		
(Summerlyn Place Apts.)	WR-608, SUB 7	(07/31/2012)
BRC Twin Oaks, LLC		
(Legacy at Twin Oaks Apts.)	WR-844, SUB 5	(12/05/2012)
BVF Paces Arbor, LLC		
(Berkshires on Lynn Lake Apts.)	WR-428, SUB 4	(04/02/2012)
BVF Paces Forest, LLC		
(Berkshires on Millbrook Apts.)	WR-427, SUB 4	(04/02/2012)
Carolina Parks, LLC		
(Cottage Cove Mobile Home Park)	WR-591, SUB 3	(01/04/2012)
Continental 221 Fund, LLC		
(Springs at Asheville Apts.)	WR-911, SUB 6	(08/14/2012)
Empirian Highlands, LP and Empirian Alexander Pointe, LLC		
(Empirian Highlands Apts.)	WR-508, SUB 4	(06/05/2012)
FG-92 Deerwood, LLC, et al.		
(Marquis at Preston Apts.)	WR-352, SUB 6	(01/09/2012)
Fund Beckanna, LLC		
(Beckanna on Glenwood Apts.)	WR-907, SUB 4	(02/14/2012)
Galleria Village Apartments, LLC		
(Galleria Apartments)	WR-367, SUB 8	(01/25/2012)
GS Hamptons, LLC		
(Hampton Apartments)	WR-732, SUB 4	(01/30/2012)
Hawthorne Axis Bainbridge, LLC		
(Bainbridge in the Park Apts.)	WR-1024, SUB 2	(11/13/2012)
Homestead MHP, LLC		
(Homestead Village MHP)	WR-978, SUB 2	(01/04/2012)
Kayser Enterprises Two, LLC		
(Quail Forest Apartments)	WR-435, SUB 5	(10/09/2012)
Lake Brandt Triad Apt. Portfolio, LLC		
(Lake Brandt Apartments)	WR-495, SUB 5	(12/12/2012)

ORDER CANCELING CERTIFICATE OF AUTHORITY *(Continued)*
Orders Issued

Company	Docket No.	Date
LVP Eastchase, LLC		
(Beacon Eastchase Apts.)	WR-716, SUB 4	(02/27/2012)
Melrose Apartments, LLC		
(Melrose Apartments)	WR-1268, SUB 1	(10/18/2012)
North Hills East Retail I, LLC		
(Park and Market Apts.)	WR-967, SUB 2	(06/01/2012)
NR Arbors Property Owner LLC		
(The Arbors Apartments)	WR-1199, SUB 1	(10/24/2012)
One Norman Square Limited Partnership		
(One Norman Square Apts.)	WR-447, SUB 3	(07/30/2012)
Patriot's Pointe, LLC		
(Patriot's Pointe Apartments)	WR-297, SUB 4	(02/22/2012)
POAA, L.L.C.		
(Pines of Ashton Apartments)	WR-834, SUB 8	(06/01/2012)
Stratford Apartment Properties, LLC		
(Stratford Apartments)	WR-523, SUB 4	(08/28/2012)
Silverstone Apartments, LLC		
(Silverstone Apartments)	WR-902, SUB 4	(12/13/2012)
Sompal Beach Lake Associates, LLC		
(Beech Lake Apartments)	WR-1025, SUB 2	(01/04/2012)
Steele Creek Apt. Properties, LLC		
(Bell Steele Creek Apts.)	WR-186, SUB 9	(08/27/2012)
Summit Green LLC		
(Ashford Green Apts.)	WR-539, SUB 2	(11/01/2012)
VAC L.L.L.P.		
(Brook Hill Apartments)	WR-831, SUB 91	(06/01/2012)
Waterford Apartments, LLC		
(Waterford Apartments)	WR-1127, SUB 1	(03/06/2012)
6014 W. T. Harris Boulevard, LLC		
(Delta Crossing Apts.)	WR-1122, SUB 1	(01/25/2012)

FG-92-Deerwood, LLC, et al. -- WR-352, SUB 6; Order Denying Motion to Rescind Order and Motion for Stay (01/23/2012)

GS Carmel, LLC -- WR-927, SUB 3; Order Rescinding Previous Commission Orders and Restoring Certificate of Authority *(Carmel on Providence Apts.)* (08/16/2012)

Steele Creek Apartments NC, L.P. -- WR-905, SUB 3; Order Rescinding Previous Commission Orders and Restoring Certificate of Authority *(Alta Steele Creek Apts.)* (08/20/2012)

The Carlisle Apartments, LP -- WR-923, SUB 4; Order Rescinding Previous Commission Orders and Restoring Certificate of Authority *(Phillip Univ. Center Apts.)* (08/24/2012)

ORDERS AND DECISIONS LISTED

RESALE OF WATER AND SEWER – Certificate

**ORDER GRANTING CERTIFICATE OF AUTHORITY
AND APPROVING RATES**
Orders Issued

Company	Docket No.	Date
ACG Burlington, LLC		
(Westwood Forest MHP)	WR-1324, SUB 0	(09/11/2012)
ACG Greensboro, LLC		
(Cranbrook Village MHP)	WR-1344, SUB 0	(11/15/2012)
Admiral Pointe, LLC		
(Admiral Pointe Apartments)	WR-1205, SUB 0	(02/21/2012)
Amelia Village Phase I, LLC		
(Amelia Village Apartments)	WR-1220, SUB 0	(02/27/2012)
Ardsley Commons, LLC		
(Ardsley Commons Apts.)	WR-1256, SUB 0	(05/15/2012)
Asheville Apartments Investors, LLC		
(Reserve at Asheville Apts.)	WR-1327, SUB 0	(09/26/2012)
Ashford Green Apartments, LLC		
(Ashford Creek Apartments)	WR-1341, SUB 0	(11/01/2012)
Autumn Woods Apartments Manager, LLC		
(Autumn Woods Apts.)	WR-1261, SUB 0	(05/21/2012)
Avalon Apartments DE, LLC		
(Avalon Apartments)	WR-1348, SUB 0	(11/28/2012)
Banks; Parks Brown		
(Lakeview Mobile Home Park)	WR-849, SUB 1 W-1244, SUB 10	(03/07/2012)
(Brownwood Mobile HP)	WR-849, SUB 2 W-1244, SUB 11	(03/07/2012)
(River Oak Mobile HP)	WR-849, SUB 3 W-1244, SUB 12	(03/07/2012)
BHC – Country Club, LLC		
(Country Club Apartments)	WR-1188, SUB 0	(02/28/2012)
Brickettwood Apartments, LLC		
(Brickettwood Glyn Apartments)	WR-1276, SUB 0	(06/18/2012)
Brier Creek Luxury Apts., LTD. Partnership		
(The Jamison at Brier Creek Apts.)	WR-1279, SUB 0	(06/19/2012)
Bruton; Debra Sue		
(The Family Lodge Apartments)	WR-1240, SUB 0	(04/17/2012)
BVF Kensington Limted Partnership		
(Kensington Place Apartments)	WR-1245, SUB 0	(04/25/2012)
Cambridge on Elm, LLC		
(Cambridge on Elm Apartments)	WR-1260, SUB 0	(05/15/2012)

ORDER GRANTING CERTIFICATE OF AUTHORITY
AND APPROVING RATES *(Continued)*
Orders Issued

Company	Docket No.	Date
Cape Fear Multifamily, LLC		
(The Astoria at Hope Mills Apts.)	WR-1264, SUB 0	(05/30/2012)
Centennial Centerview, LP		
(Century Centerview Apts.)	WR-1272, SUB 0	(06/12/2012)
CH Realty V/Park and Market L.L.C		
(Park and Market Apartments)	WR-1303, SUB 0	(07/31/2012)
City View Commercial, LLC		
(City View at Southside Apts.)	WR-1236, SUB 0	(04/10/2012)
Colonial Realty Limited Partnership		
(The Enclave Apartments)	WR-437, SUB 25	(08/08/2012)
CREF Tribute LLC		
(Tribute Apartments)	WR-1195, SUB 0	(01/30/2012)
CRP/WF Creekstone, LLC		
(Woodfield Creekstone Apts.)	WR-1319, SUB 0	(08/29/2012)
CSFB 2007-C2 Summerlyn, LLC		
(Summerlyn Place Apartments)	WR-1302, SUB 0	(07/31/2012)
CSMC 2007-C3 Elm Street Living, LLC		
(Paces Village Apartments)	WR-1291, SUB 0	(07/05/2012)
CWSFG 91, LLC, et al.		
(Marquis at Preston Apartments)	WR-1207, SUB 0	(02/21/2012)
Delta Crossing NC Partners, LLC		
(Delta Crossing Apartments)	WR-1219, SUB 0	(03/14/2012)
E.O. Johnson Properties, LLC		
(Sedgefield Square Apartments)	WR-1191, SUB 0	(01/17/2012)
EWT 21, LLC		
(Wingate Townhouse Apts.)	WR-1354, SUB 0	(12/05/2012)
Fortress Park, LLC		
(The Park Apartments)	WR-1193, SUB 0	(01/30/2012)
Fund X EBC Raleigh, LLC		
(The Exchange at Brier Creek Apts.)	WR-1209, SUB 0	(02/28/2012)
G Partnership, L. P.		
(The Landings Apartments)	WR-1262, SUB 0	(05/16/2012)
GGT Whitehall Ventures NC, LLC		
(Whitehall Parc Apartments)	WR-1338, SUB 0	(10/25/2012)
Goldsboro Properties, LLC		
(Granville Oaks Apt. Homes)	WR-1263, SUB 0	(05/21/2012)
GRDF Quarterside, LLC, et al		
(Quarterside Apartments)	WR-1210, SUB 0	(03/05/2012)
Greenway at Fisher Park, LLC		
(Greenway at Fisher Park Apts.)	WR-1322, SUB 0	(09/07/2012)

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES *(Continued)*

Orders Issued

Company	Docket No.	Date
GS Brightleaf Subsidiary, LLC		
(Artisan at Brightleaf Apts.)	WR-1321, SUB 0	(09/07/2012)
GS Villages Chapel Hill, LLC		
(The Villages at Chapel Hill Apts.)	WR-1203, SUB 0	(02/20/2012)
Hawthorne-Midway Madison Place, LLC		
(Madison Place Apartments)	WR-1300, SUB 0	(07/27/2012)
Heritage Arden I, LLC, et al.		
(Arden Woods Apartments)	WR-1298, SUB 0	(07/24/2012)
Heritage Williamsburg I, LLC, et al.		
(Williamsburg Manor Apts.)	WR-1299, SUB 0	(07/24/2012)
Hillsborough Apartments Partners, LLC		
(Patriot's Pointe Apartments)	WR-1206, SUB 0	(02/22/2012)
Horizon Acquisition #1, LLC		
(Autumn View Apartments)	WR-1306, SUB 0	(08/09/2012)
Innisbrook Village, LLC		
(Innisbrook Village Apts.)	WR-1278, SUB 0	(06/19/2012)
Lake Clair, LLC		
(Lake Clair Apartments)	WR-1223, SUB 0	(03/27/2012)
Lawndale Associates, LLC		
(Winstead Commons Apts.)	WR-1253, SUB 0	(05/09/2012)
Legacy at Twin Oaks, LLC		
(Legacy at Twin Oaks Apts.)	WR-1353, SUB 0	(12/05/2012)
Lenoxplace Apartments, LLC		
(Lenox at Garners Station Apts.)	WR-1305, SUB 0	(08/07/2012)
Mallard Green, LLC		
(Mallard Green Apartments)	WR-1259, SUB 0	(05/16/2012)
McArthur Partners, LLC		
(McArthur Park Apts., Phase I)	WR-1292, SUB 0	(07/30/2012)
Melrose Apartments, LLC		
(Melrose Apartments)	WR-1268, SUB 0	(05/31/2012)
MFREVF-Piedmont, LLC		
(The Piedmont at Ivy Meadow Apts.)	WR-1190, SUB 0	(01/18/2012)
Mitchell Lerner, et al.		
(Baird Cove Apartments)	WR-1252, SUB 0	(05/09/2012)
Morgan Polo Run, LLC		
(The Trails of North Hills Apts.)	WR-1301, SUB 0	(07/30/2012)
MTS Residential, LLC		
(Fountains at Mooresville Town Square Apartments)	WR-1274, SUB 0	(06/12/2012)

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES *(Continued)*

Orders Issued

Company	Docket No.	Date
NC Apartment Rentals, LLC		
(Medical Park West Townhomes Apts.)	WR-1237, SUB 0	(04/10/2012)
New Park Ridge Associates, LLC		
(Park Ridge Estates Apartments)	WR-1225, SUB 0	(03/28/2012)
North Carolina Apartments I, LP		
(Village Summit Apartments)	WR-1241, SUB 0	(04/23/2012)
Northlake Investors 288, LLC		
(Ashton Reserve at Northlake Apts.)	WR-1208, SUB 0	(02/27/2012)
Northlake Residential Associates LLC		
(Madison Square at Northlake Apts.)	WR-1361, SUB 0	(12/19/2012)
Northland Governor's Point, LLC		
(Governor's Point Apartments)	WR-1257, SUB 0	(05/15/2012)
Northland River Birch L.P.		
(River Birch Apts., Phase II)	WR-1258, SUB 0	(05/01/2012)
NR Charlotte, LLC		
(The Vue Charlotte on 5th Apts.)	WR-1343, SUB 0	(11/05/2012)
Ocean Lynn Lake, LLC		
(The Atlantic – Lynn Lake Apts.)	WR-1265, SUB 0	(05/30/2012)
Ocean Millbrook, LLC		
(The Atlantic Millbrook Apts.)	WR-1266, SUB 0	(05/30/2012)
PAMI Grand Oaks, LLC		
(Grand Oaks Apartments)	WR-1347, SUB 0	(11/28/2012)
Phillips Mallard Creek, LLC		
(Phillips Mallard Creek Apts.)	WR-1310, SUB 0	(08/15/2012)
POAA II, L.L.C.		
(Pines of Ashton Apartments)	WR-1282, SUB 0	(06/21/2012)
PRG Bainbridge Associates, LLC		
(Bainbridge in the Park Apts.)	WR-1356, SUB 0	(12/12/2012)
PRG Windsor Square Associates, LLC		
(South Square Townhomes Apts.)	WR-1226, SUB 0	(03/28/2012)
Privet Asheville, LLC		
(Eastwood Village Apartments)	WR-1320, SUB 0	(09/07/2012)
RAIA Properties NC-4, LLC		
(One Norman Apartments)	WR-1271, SUB 0	(06/11/2012)
Retreat at Carrington Oaks, LLC		
(Carrington Place Apartments)	WR-1331, SUB 0	(10/04/2012)
RFI Cary Brook LLC		
(Cary Brook Apartments)	WR-1295, SUB 0	(07/17/2012)

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES *(Continued)*

<u>*Orders Issued*</u>

Company	Docket No.	Date
RFI Highlands, LLC		
(Highlands at Alexander Pointe Apts.)	WR-1294, SUB 0	(07/16/2012)
Ridge Apartments, LLC		
(The Ridges Apartments)	WR-1350, SUB 0	(12/04/2012)
Riverbend of Asheville, LLC		
(Verde Vista Apartments)	WR-1296, SUB 0	(07/17/2012)
Schrader Family Limited Partnership		
(Peterson Park Apartments)	WR-980, SUB 4	(05/30/2012)
Schrader Properties, LLC		
(Campus Courtyard Apts.)	WR-1334, SUB 0	(10/18/2012)
Seagrove Village MHP, LLC		
(Seagrove Village MH Park)	WR-1297, SUB 0	(07/17/2012)
Shellbrook Associates, LP		
(Shellbrook Apartments)	WR-1192, SUB 0	(01/18/2012)
SIL SF, LLC		
(Eagle Point Apartments)	WR-1342, SUB 0	(11/06/2012)
SRC Northwinds, Inc		
(Northwinds I & II Apts.)	WR-1254, SUB 0	(05/09/2012)
Steele Creek Apts. Property Owners, LLC		
(Park at Steele Creek Apts.)	WR-1332, SUB 0	(10/04/2012)
Strickland Farms Apartments, LLC		
(Strickland Farms Apartments)	WR-1304, SUB 0	(08/07/2012)
Sumare, LP		
(Sumter Square Apartments)	WR-1163, SUB 1	(04/24/2012)
Sunset Place, LLC		
(Sunset Place Apartments)	WR-1247, SUB 0	(04/30/2012)
Talbert Woods Mooresville Section I, LLC		
(Talbert Woods Townhomes I Apts.)	WR-1358, SUB 0	(12/19/2012)
Talbert Woods Mooresville Section II, LLC		
(Talbert Woods Townhomes II Apts.)	WR-1359, SUB 0	(12/19/2012)
The Lofts at Charlestown Row, LLC		
(The Lofts at Charleston Row Apartments)	WR-1313, SUB 0	(08/15/2012)
The Pointe at Robinhood Village, LLC		
(The Pointe at Robinhood Village Apartments)	WR-1339, SUB 0	(10/25/2012)

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES *(Continued)*

Orders Issued

Company	Docket No.	Date
The Quarters at Stones Bay		
(The Quarters at Stones Bay Apts.)	WR-1309, SUB 0	(08/15/2012)
Tiger Properties III, LLC		
(Arbor Creek Apartments)	WR-1102, SUB 1	(11/28/2012)
Townhouse Apartments, LLC		
(Townhouse Apartments)	WR-1235, SUB 0	(04/10/2012)
Tritex Real Estate Advisors, Inc.		
(Eastchase Apartments)	WR-1273, SUB 0	(06/12/2012)
VA Uptown LLC		
(Uptown Gardens Apartments)	WR-1346, SUB 0	(11/20/2012)
Vanstory Apartments, LLC		
(Ashbrook Pointe Apartments)	WR-126, SUB 9	(12/18/2012)
Villas at Murrayville, LLC		
(Hawthorne at Murrayville Apts.)	WR-1221, SUB 0	(03/26/2012)
Vinings at Morehead, LLC		
(Vinings at Wildwood Apts.)	WR-1216, SUB 0	(03/13/2012)
VTT Greensboro, LLC		
(Brannon Park Apartments)	WR-1243, SUB 0	(04/23/2012)
Water Garden Village, LLC		
(Water Garden Village Apts.)	WR-1315, SUB 0	(08/23/2012)
Waverly Apartments, LLC		
(The Waverly Apartments)	WR-1293, SUB 0	(07/16/2012)
Wendover at Meadowood, LLC		
(Wendover at Meadowood Apts.)	WR-1323, SUB 0	(09/11/2012)
Westdale Beech Lake, LLC		
(Beech Lake Apartments)	WR-1213, SUB 0	(03/06/2012)
Westdale Brentmoor, LLC		
(Brentmoor Apartments)	WR-1317, SUB 0	(08/28/2012)
Westdale Galleria Village, LLC		
(Galleria Apartment Homes)	WR-1224, SUB 0	(03/27/2012)
Westdale Lenox, LLC		
(Lenox at Patterson Place Apts.)	WR-1351, SUB 0	(12/05/2012)
Winstead Warehousing, LLC		
(Brandonshire Apartments)	WR-1222, SUB 0	(03/27/2012)
Winston North Forsyth MHP LLC		
(Winston North Forsyth MHP)	WR-1357, SUB 0	(12/18/2012)
7850 Cottage Cove, LLC		
(Cottage Cove Mobile HP)	WR-1196, SUB 0	(02/06/2012)
7850 Homestead MHP, LLC		
(Homestead Village Mobile HP)	WR-1197, SUB 0	(02/06/2012)

RESALE OF WATER AND SEWER – Certificate *(Continued)*

Amelia Village Phase I, LLC -- WR-1220, SUB 0; Reissued Order Granting Certificate of Authority and Approving Rates *(Amelia Village Apts.)* (03/02/2012)

City View Commercial, LLC -- WR-1236, SUB 0; Order Reissuing Certificate of Authority and Approving Rates *(City View at Southside Apts., Phase II)* (05/11/2012)

Colonial Realty Limited Partnership -- WR-437, SUB 25; Errata Order *(The Enclave Apts.)* (08/14/2012)

CSFB 2007-C2 Summerlyn, LLC -- WR-1302, SUB 0; Reissued Order Granting Certificate of Authority and Approving Rates *(Summerlyn Place Apts.)* (09/14/2012)

GRDF Quarterside, LLC, et al. -- WR-1210, SUB 0; Errata Oder *(Quarterside Apts.)* (03/05/2012)

MFREVF-Piedmont, LLC -- WR-1190, SUB 0; Reissued Order Granting Certificate of Authority and Approving Rates *(The Piedmont at Ivy Meadow Apts.)* (01/20/2012)

Sunset Place, LLC -- WR-1247, SUB 0; Reissued Order Granting Certificate of Authority and Approving Rates *(Sunset Place Apartments)* (05/01/2012)

Waverly Apartments, LLC -- WR-1293, SUB 0; Errata Order *(The Waverly Apts.)* (07/18/2012)

ORDER GRANTING HWCCWA CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued

Company	Docket No.	Date
Apple Creek, LLC		
(Village of Pickwick Apts. 2)	WR-974, SUB 1	(02/22/2012)
Brentwood West Company, LLC		
(Brentwood West Apartments)	WR-1160, SUB 1	(04/24/2012)
Brook Dana, LLC		
(Brook Hill Apartments)	WR-1281, SUB 0	(06/21/2012)
Bruton; Debra Sue		
(The Family Lodge Apts., Phase I)	WR-1240, SUB 2	(09/07/2012)
BVF Chase Mooring LLC		
(Berkshires at Pecan Grove Apts.)	WR-1246, SUB 0	(04/25/2012)
BVF Osprey Landing, LLC		
(Osprey Landing Apartments)	WR-1255, SUB 0	(05/15/2012)
BVF Wimbledon Chase, LLC		
(Wimbledon Chase Apartments)	WR-1244, SUB 0	(04/25/2012)
CSP Lexington Farms, LLC		
(Lexington Farms Apartments)	WR-1269, SUB 0	(06/04/2012)
EWT 22, LLC		
(The Willows Apartments)	WR-1329, SUB 0	(09/26/2012)
FCP Glen Lennox, LLC		
(Glen Lennox Apartments)	WR-1198, SUB 0	(02/13/2012)
G***&I VI Brynn Marr LP***		
(Brynn Marr Village Apartments)	WR-759, SUB 4	(01/18/2012)
G&I VI Colony Village LP		
(Colony Village Apartments)	WR-779, SUB 5	(01/18/2012)

ORDER GRANTING HWCCWA CERTIFICATE OF AUTHORITY AND APPROVING RATES *(Continued)*
Orders Issued

Company	Docket No.	Date
GS Villages Chapel Hill, LLC		
(The Villages at Chapel Hill Apts.)	WR-1203, SUB 1	(04/17/2012)
H.R. Realty Company, LLC		
(Hunting Ridge Apartments)	WR-1161, SUB 1	(04/24/2012)
Heritage Lakes I, LLC, et al.		
(The Lakes Apartments)	WR-1202, SUB 0	(02/14/2012)
Lake Clair, LLC		
(Lake Clair Apartments)	WR-1223, SUB 1	(07/24/2012)
Montecito Company, LLC		
(Montecito Apartments)	WR-1162, SUB 1	(04/24/2012)
New Cardinal Woods Associates, LLC		
(Cary Pines Apartments)	WR-1232, SUB 0	(04/04/2012)
New Honeytree Associates, L.P.		
(Honeytree Apartments)	WR-1227, SUB 0	(03/28/2012)
New Woodcreek Associates, LL		
(Woodcreek Apartments)	WR-1233, SUB 0	(04/04/2012)
Oakhurst Farms of Raleigh, LLC		
(Village of Pickwick Apts. 1)	WR-1018, SUB 1	(02/22/2012)
PRG Lake Johnson Mews Associates, LLC		
(Lake Johnson Mews Apartments)	WR-1234, SUB 0	(04/04/2012)
PRG Landmark Associates, LLC		
(The Village at Lake Boone Trail Apts.)	WR-1229, SUB 0	(04/04/2012)
PRG Village Resort Associates, LLC		
(Glendare Park Apartments)	WR-1230, SUB 0	(04/04/2012)
Q. R. Realty Company, LLC		
(Quail Ridge Apartments)	WR-1159, SUB 1	(04/24/2012)
REBA Reafield, LLC, et al.		
(Reafield Village Apartments)	WR-793, SUB 2	(08/29/2012)
Shellbrook Associates, LP		
(Shellbrook Apartments)	WR-1192, SUB 1	(04/24/2012)
Silverstone Apartment Homes, LLC		
(Silverstone Apartments)	WR-1355, SUB 0	(12/13/2012)
Treetop Associates, L.P.		
(Tree Top Apartments)	WR-1231, SUB 0	(04/04/2012)
West Montecito Company, LP		
(Montecito West Apartments)	WR-1164, SUB 1	(04/24/2012)

Sumare, LP -- WR-1163, SUB 1; Reissued Order Granting HWCCWA Certificate of Authority and Approving Rates *(Sumter Square Apartments)* (04/25/2012)

RESALE OF WATER AND SEWER — Complaint

BACM 2005-6 Lake Point Drive, LLC -- WR-1129, SUB 1; Order Dismissing Complaint and Closing Docket *(Koree Boyd)* (10/05/2012)

RESALE OF WATER AND SEWER – Miscellaneous

CSP Fox Hollow, LLC -- WR-1187, SUB 1; Order Approv. Refund Plan (09/10/2012)

RESALE OF WATER AND SEWER -- Reinstating Certificate

Charleston Place, LLC -- WR-700, SUB 1; Order Rescinding Previous Commission Orders and Restoring Certificate of Authority (05/11/2012)

Oglesby Properties, LLC -- WR-838, SUB 1; Order Rescinding Previous Commission Order and Restoring Certificate of Authority (06/20/2012)

RESALE OF WATER AND SEWER -- Sale/Transfer

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued

Company	Docket No.	Date
AERC Arboretum I, LLC		
(The Arboretum Apartments)	WR-1277, SUB 0 WR-1200, SUB 1	(06/19/2012)
AERC Crossroads, L.P.		
(The Park at Crossroads Apartments)	WR-1328, SUB 0 WR-328, SUB 4	(09/26/2012)
AERC Southpoint Village, LLC		
(Southpoint Village Apartments)	WR-1312, SUB 0 WR-129, SUB 18	(08/15/2012)
AMFP II Waterford Village, LLC		
(Waterford Village Apartments)	WR-1340, SUB 0 WR-404, SUB 8	(10/30/2012)
Arbor Village MMXI, LLC		
(Arbor Village Apartments)	WR-1239, SUB 0 WR-1151, SUB 1	(04/17/2012)
Atwood, LLC		
(Knollwood Apartments)	WR-1283, SUB 0 WR-831, SUB 92	(07/02/2012)
Bell Fund IV Morrison Apartments, LLC		
(Bell Morrison Apartments)	WR-1250, SUB 0 WR-643, SUB 4	(05/08/2012)
BES Steele Creek Fund IX, LLC		
(Preserve at Steele Creek Apts.)	WR-1352, SUB 0 WR-905, SUB 5	(12/05/2012)

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES *(Continued)*

Orders Issued

Company	Docket No.	Date
BHC – Pine Winds, LLC		
(Pine Winds Apartments)	WR-1242, SUB 0 WR-971, SUB 4	(04/23/2012)
BHI-SEI Mariners, LLC		
(Mariners Crossing Apartments)	WR-1228, SUB 0 WR-96, SUB 9	(04/03/2012)
BRC Jacksonville Commons, LLC		
(Reserve at Jacksonville Commons Apts.)	WR-1275, SUB 0 WR-641, SUB 3	(06/12/2012)
Carolina Village MHC, LLC		
(Carolina Village Mobile HP)	WR-1215, SUB 0 WR-1013, SUB 1	(03/13/2012)
CoHeritage Oak Pointe, LLC		
(Oak Pointe Apartments)	WR-1316, SUB 0 WR-656, SUB 5	(08/23/2012)
Colonial NC, LLC		
(Colonial Townhouse Apts.)	WR-1284, SUB 0 WR-831, SUB 93	(07/02/2012)
CSP Hunt's View, LLC		
(Hunt's View Apartments)	WR-1217, SUB 0 WR-158, SUB 4	(03/14/2012)
CWS Carmel Valley Associates, L.P.		
(Marquis of Carmel Valley Apts.)	WR-1267, SUB 0 WR-10, SUB 8	(05/31/2012)
DWSS Charlotte, LLC		
(Lake Point Apartments)	WR-1330, SUB 0 WR-1129, SUB 2	(10/05/2012)
FCP West Village Phase I Owner, LLC		
(West Village Apartments)	WR-1251, SUB 0 WR-600, SUB 2	(05/08/2012)
Fund Asbury Village, LLC		
(Camden Asbury Village Valley Apts.)	WR-1211, SUB 0 WR-940, SUB 3	(03/06/2012)
Guardian Tryon Village, LLC		
(The Windsor at Tryon Village Apts.)	WR-1335, SUB 0 WR-750, S UB 4	(10/22/2012)
Guardian Wakefield, LLC		
(Columns at Wakefield Apartments)	WR-1337, SUB 0 WR-177, SUB 10	(10/25/2012)

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES *(Continued)*

Orders Issued

Company	Docket No.	Date
Hawthorne-Midway Meadows, LLC		
(Hawthorne at the Meadows Apts.)	WR-1307, SUB 0 WR-783, SUB 3	(08/09/2012)
Hawthorne-Midway Summerwood, LLC		
(Summerwood Apartments)	WR-1194, SUB 0 WR-855, SUB 1	(01/30/2012)
Hawthorne-Midway Vista Park, LLC		
(Hawthorne at the Greene Apts.)	WR-1349, SUB 0 WR-1183, SUB 1	(11/28/2012)
Holly NC, LLC		
(Holly Hills Apartments)	WR-1290, SUB 0 WR-831, SUB 97	(07/05/2012)
Horizon Acquisition # 3, LLC		
(Heritage Apartments)	WR-1325, SUB 0 WR-519, SUB 1	(09/19/2012)
KIWA, LLC		
(Kingswood Apartments)	WR-1287, SUB 0 WR-831, SUB 98	(07/03/2012)
LaSalle NC, LLC		
(Duke Manor Apartments)	WR-1286, SUB 0 WR-831, SUB 96	(07/03/2012)
Morreene, LLC		
(Chapel Tower Apartments)	WR-1289, SUB 0 WR-831, SUB 100	(07/05/2012)
MP Regatta, LLC		
(Regatta at Lake Lynn Apts.)	WR-1318, SUB 0 WR-1111, SUB 1	(08/28/2012)
Neyland Apartment Associates Two, LLC		
(Independence Park Apartments)	WR-1214, SUB 0 WR-790, SUB 4	(03/12/2012)
North Estes, LLC		
(Estes Park Apartments)	WR-1288, SUB 0 WR-831, SUB 99	(07/03/2012)
Northland River Birch I LLC		
(River Birch Apts., Phase I)	WR-1248, SUB 0 WR-477, SUB 4	(05/01/2012)

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES *(Continued)*

Orders Issued

Company	Docket No.	Date
Northwestern Mutual Life Insurance Co.		
(Southpoint Village Apartments)	WR-129, SUB 16 WR-583, SUB 6	(02/22/2012)
(Chapel Hill North Apartments)	WR-129, SUB 17 WR-1083, SUB 2	(02/22/2012)
(Trinity Commons at Erwin Apts.)	WR-129, SUB 19 WR-1090, SUB 2	(12/12/2012)
NR Alpha Mill Property Owner, LLC		
(Alpha Mill Apartments)	WR-1238, SUB 0 WR-559, SUB 5	(04/10/2012)
NR Arboretum Property Owner LLC		
(The Residences at Arboretum Apts.)	WR-1200, SUB 0 WR-589, SUB 3	(02/14/2012)
NR Arbors Property Owner LLC		
(The Arbors Apartments)	WR-1199, SUB 0 WR-135, SUB 10	(02/14/2012)
NR Blakeney Property Owner LLC		
(The Apartments at Blakeney)	WR-1201, SUB 0 WR-658, SUB 5	(02/14/2012)
Parks B. Banks & Carol Banks		
(Riverview Mobile Home Park)	WR-1212, SUB 0 WR-578, SUB 4	(03/06/2012)
Parkside Drive, LLC		
(Highlands at Brier Creek Village Apts.)	WR-1218, SUB 0 WR-639, SUB 2	(03/14/2012)
Post South End, L.P.		
(Post South End Apartments)	WR-1326, SUB 0 WR-889, SUB 1	(09/19/2012)
SHLP Chancery Village, LLC		
(Chancery Village at the Park Apts.)	WR-1204, SUB 0 WR-1079, SUB 1	(02/21/2012)
Summit Allerton, LLC		
(Allerton Place Apartments)	WR-1280, SUB 0 WR-1166, SUB	(06/26/2012)
TR Vinoy, LLC		
(The Vinly at Innovation Park Apts.)	WR-1308, SUB 0 WR-531, SUB 5	(08/14/2012)
Waterlynn Ridge Apartments, LLC, et al.		
(Waterlynn Ridge Apartments)	WR-1360, SUB 0 WR-1027, SUB 1	(12/19/2012)

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES *(Continued)*

Orders Issued

Company	Docket No.	Date
Wells Fargo Bank, N.A., Trustee		
(Autumn Ridge Apartments)	WR-1345, SUB 0 WR-786, SUB 8	(11/15/2012)
WMCI Charlotte XIII, LLC		
(Bexley Village at Concord Mills Apts.)	WR-1189, SUB 0 WR-916, SUB 2	(01/17/2012)
WMCI Raleigh VI, LLC		
(Bexley at Triangle Park Apts.)	WR-1311, SUB 0 WR-586, SUB 5	(08/15/2012)
YES Companies EXP, LLC		
(Foxhall Village MH Community)	WR-1336, SUB 0 WR-534, SUB 6	(10/23/2012)
(Stony Brook North MH Community)	WR-1336, SUB 1 WR-535, SUB 3	(10/23/2012)
(Village Park MH Community)	WR-1336, SUB 2 WR-597, SUB 5	(10/23/2012)
(Green Spring Valley MH Comm.)	WR-1336, SUB 3 WR-536, SUB 3	(10/23/2012)
(Gallant Estates MH Community)	WR-1336, SUB 4 WR-533, SUB 1	(10/24/2012)
(Oakwood Forest MH Community)	WR-1336, SUB 5 WR-532, SUB 5	(10/24/2012)
(Woodlake MH Community)	WR-1336, SUB 6 WR-532, SUB 6	(10/24/2012)

AMFP II Waterford Village, LLC -- WR-1340, SUB 0 & WR-404, SUB 8; Errata Order (11/02/2012)

North Estes, LLC -- WR-1288, SUB 0 & WR-831, SUB 99; Errata Order (07/03/2012)

NR Arboretum Property Owner, LLC -- WR-1200, SUB 0 & WR-859, SUB 3; Reissued Order Granting Transfer of Certificate of Authority and Approving Rates (04/03/2012)

RP Barnes, LLC -- WR-1285,

SUB 0; WR-831, SUB 94; Order Granting Transfer of HWCCWA Certificate of Authority and Approving Rates *(University Lake Apts.)* (07/02/2012)

SUB 1; WR-831, SUB 95; Order Granting Transfer of HWCCWA Certificate of Authority and Approving Rates *(Royal Park Apartments)* (07/02/2012)

Schmitz; Robert L. -- WR-1249, SUB 0; WR-1155, SUB 1; Order Grant. Transfer of HWCCWA Certif. of Authority and Approv. Rates *(Oaktree Apts.)* (05/08/2012)

ORDERS AND DECISIONS LISTED

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through

ORDER APPROVING TARIFF REVISION
Orders Issued

Company	Docket No.	Date
Amelia Village, LLC		
(Amelia Village Apartments)	WR-44, SUB 2	(02/13/2012)
Abberly Green – Garner – Phase I, L.P.		
(Abberly Place Apartments)	WR-305, SUB 6	(08/08/2012)
Abberly Green – Mooresville – Phase I, L.P.		
(Abberly Green Apts., Phase I)	WR-457, SUB 5	(10/09/2012)
Abberly Green – Mooresville – Phase II, L.P.		
(Abberly Green Apts., Phase II)	WR-686, SUB 3	(10/09/2012)
Addison Point, LLC		
(Addison Point Apartments)	WR-748, SUB 4	(09/06/2012)
Alaris Village Apartments, LLC		
(Alaris Village Apartments)	WR-894, SUB 3	(05/07/2012)
AMFP II Four Seasons, LLC		
(Four Seasons at Umstead Park Apts.)	WR-1165, SUB 1	(07/31/2012)
AMFP 1 Hamilton Ridge LLC		
(Hamilton Ridge Apartments)	WR-805, SUB 5	(08/13/2012)
Apple Creek, LLC		
(Village at Pickwick Apartments 2)	WR-974, SUB 2	(04/03/2012)
Arbor Village MMXI, LLC		
(Arbor Village Apartments)	WR-1239, SUB 1	(08/21/2012)
Ardsley Commons, LLC		
(Ardsley Commons Apartments)	WR-1256, SUB 1	(09/25/2012)
Ashborough Investors, LLC		
(Ashborough Apartments)	WR-489, SUB 4	(04/03/2012)
Ashborough Investors, LLC		
(Ashborough Apartments)	WR-489, SUB 5	(08/06/2012)
Ashford SPE 2, LLC		
Ashford Place Apts., Phase II)	WR-990, SUB 3	(07/25/2012)
Ashford SPE, LLC		
(Ashford Place Apts., Phase I)	WR-555, SUB 7	(07/25/2012)
Ashley Oaks, LLC		
(Ashley Oaks Apartments)	WR-1147, SUB 1	(09/12/2012)
Ashley Park Associates, LLC		
(Ashley Park at Brier Creek Apts.)	WR-960, SUB 1	(11/20/2012)
Ashton Village, Limited Partnership		
(Abberly Place Apartments)	WR-802, SUB 5	(08/08/2012)
Aspen Woods, LLC		
(Aspen Woods Apts.)	WR-1143, SUB 1	(08/27/2012)

ORDER APPROVING TARIFF REVISION *(Continued)*
Orders Issued

Company	Docket No.	Date
Associated Apartment Investors/Dutch Village, LP		
(Arbor Ridge Apartments)	WR-929, SUB 1	(09/17/2012)
Auston Grove – Raleigh Apts. L. P.		
(Auston Grove Apartments)	WR-233, SUB 11	(08/08/2012)
Auston Woods Apts. - Charlotte-Phase I-LP		
(Auston Woods Apartments)	WR-232, SUB 4	(08/27/2012)
Auston-Woods Charlotte-Phase II, LP		
(Auston Woods II Apartments)	WR-721, SUB 4	(08/27/2012)
Avery Millbrook, LLC		
(Millbrook Apartments I)	WR-1020, SUB 6	(09/06/2012)
(Avery Square Apartments)	WR-1020, SUB 7	(10/17/2012)
Barrington Apartments, LLC		
(Barrington Apartments)	WR-384, SUB 10	(08/01/2012)
BBR/Barrington, LLC		
(Barrington Place Apartments)	WR-619, SUB 6	(08/20/2012)
BBR/Brookford, LLC		
(Brookford Place Apartments)	WR-614, SUB 6	(11/19/2012)
BBR/Fairington, LLC		
(The Fairington Apartments)	WR-952, SUB 3	(07/27/2012)
BBR/Hampton, LLC		
(The Hamptons at Southpark Apts.)	WR-606, SUB 6	(07/27/2012)
BBR/Mallard Creek, LLC		
(Bridges at Mallard Creek Apts.)	WR-609, SUB 6	(07/27/2012)
BBR/Marina Waterfront, LLC		
(Marina Shores Waterfront Apts.)	WR-605, SUB 6	(07/27/2012)
BBR/Oak Hollow, LLC		
(Oak Hollow Apartments)	WR-1009, SUB 3	(03/19/2012)
BBR/Oakbrook, LLC		
(Oakbrook Apartments)	WR-613, SUB 6	(07/27/2012)
BBR/Paces Commons, LLC		
(Paces Commons Apartments)	WR-604, SUB 7	(07/27/2012)
BBR/Quail Hollow, LLC		
(Bridges at Quail Hollow Apts.)	WR-615, SUB 6	(07/27/2012)
BBR/Wind River, LLC		
(Bridges at Wind River Apts.)	WR-611, SUB 6	(08/17/2012)
Beachwood Associates, L.L.C.		
(Beachwood Park Apartments)	WR-880, SUB 1	(11/07/2012)
Beaver Creek Section I Associates, L.L.C.		
(Beaver Creek Townhomes Apts. (Sec. I)	WR-881, SUB 1	(03/19/2012)

ORDER APPROVING TARIFF REVISION *(Continued)*
Orders Issued

Company	Docket No.	Date
Beaver Creek Sections II Associates, L.L.C.		
(Beaver Creek Townhomes Apts. (Sec. II)	WR-878, SUB 1	(03/19/2012)
Bel Hickory Grove Holdings LLC		
(Kimmerly Glen Apartments)	WR-1054, SUB 2	(09/12/2012)
Bel Pineville Holdings LLC		
(Berkshire Place Apartments)	WR-1037, SUB 2	(09/12/2012)
Bel Ridge Holdings LLC		
(McAlpine Ridge Apartments)	WR-1053, SUB 2	(09/17/2012)
Bell BR Meadowmont, LLC		
(Bell Meadowmont Apartments)	WR-1014, SUB 2	(01/03/2012)
Bell Fund IV Morrison Apartments, LLC		
(Bell Morrison Apartments)	WR-1250, SUB 1	(08/31/2012)
Belmont at Southpoint, LLC		
(Berkeley at Southpoint Apartments)	WR-187, SUB 8	(10/08/2012)
Best Mulch, Inc.		
(Clairmont Crest Mobile HP)	WR-513, SUB 4	(10/22/2012)
BHC – Country Club, LLC		
(Country Club Apartments)	WR-1188, SUB 1	(11/27/2012)
BMA Eden Apartments, LLC		
(Arbor Glen Apartments)	WR-728, SUB 3	(02/20/2012)
BMA Huntersville Apartments, LLC		
(Huntersville Apartments)	WR-811, SUB 4	(08/20/2012)
BMA Monroe III Apartments, LLC		
(Woodbrook Apartments)	WR-812, SUB 5	(09/18/2012)
BMA Shelby Apartments NC, LLC		
(Marion Ridge Apartments)	WR-709, SUB 3	(02/20/2012)
BMA Wexford Apartments, LLC		
(Wexford Apartments)	WR-813, SUB 4	(08/20/2012)
BNP/Abbington, LLC		
(Abbington Place Apartments)	WR-454, SUB 6	(08/17/2012)
BNP/Chason Ridge LLC		
(Chason Ridge Apartments)	WR-64, SUB 10	(03/19/2012)
BNP/Harris Hill, LLC		
(Bridges at Mallard Creek Apts. – Phase I)	WR-393, SUB 7	(07/26/2012)
BNP/Pepperstone, LLC		
(Pepperstone Apartments)	WR-445, SUB 7	(08/17/2012)
BNP/Savannah, LLC		
(Savannah Place Apartments)	WR-474, SUB 5	(11/19/2012)
BNP/Southpoint, LLC		
(Bridges at Southpoint Apts.)	WR-333, SUB 9	(08/17/2012)

ORDER APPROVING TARIFF REVISION *(Continued)*
Orders Issued

Company	Docket No.	Date
BNP/Waterford, LLC		
(Waterford Place Apartments)	WR-444, SUB 7	(08/17/2012)
BNP/Woods Edge, LLC		
(Woods Edge Apartments)	WR-1010, SUB 3	(08/17/2012)
Bouwfonds North Pointe, LP		
(North Pointe Commons Apts.)	WR-895, SUB 1	(10/18/2012)
Bouwfonds Pavilion Crossing II, LLC		
(Pavilion Crossings II Apartments)	WR-598, SUB 5	(10/17/2012)
Bouwfonds Pavilion Crossings I, LLC		
(Pavilion Crossings I Apartments)	WR-599, SUB 5	(10/17/2012)
BR Chapel Hill, LLC		
(The Park at Chapel Hill Apts.)	WR-1088, SUB 1	(01/03/2012)
Brannigan Village Apartments, L.L.C.		
(Brannigan Village Apartments)	WR-380, SUB 7	(05/07/2012)
BRC Abernathy, LLC et al.,		
(Abernathy Park Apartments)	WR-1057, SUB 2	(07/24/2012)
BRC Charlotte 485, LLC		
(Halton Park Apartments)	WR-501, SUB 5	(07/25/2012)
BRC Knightdale, LLC		
(Berkshire Park Apartments)	WR-938, SUB 3	(07/25/2012)
BRC Twin Oaks, LLC		
(Twin Oaks Apartments)	WR-844, SUB 4	(07/25/2012)
Brier Creek Luxury Apts., Ltd.		
(The Jamison at Brier Creek Apts.)	WR-1279, SUB 1	(12/03/2012)
Brightwood Crossing Apartments, LLC		
(Brightwood Apartments)	WR-543, SUB 3	(09/17/2012)
BRNA, L.L.C.		
(Bryn Athyn Apartments)	WR-75, SUB 11	(03/05/2012)
(Bryn Athyn Apartments)	WR-75, SUB 12	(08/07/2012)
Broadstone Village Apartments, LLC		
(Broadstone Village Apartments)	WR-378, SUB 7	(05/07/2012)
Brookberry Park Apartments, LLC		
(Brookberry Park Apartments)	WR-798, SUB 5	(10/30/2012)
Bruton, Debra Sue		
(The Family Lodge Apartments)	WR-1240, SUB 1	(06/18/2012)
Burd Properties of Fayetteville, LLC		
(Stoney Ridge Apartments)	WR-585, SUB 10	(03/13/2012)
(Meadowbrook at King's Grant Apts.)	WR-585, SUB 11	(03/13/2012)
(Carlson Bay Apartments)	WR-585, SUB 12	(03/14/2012)
C and J Catalyst, LLC		
(Catalyst Apartments)	WR-1116, SUB 2	(08/14/2012)

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Company	Docket No.	Date
Cambridge on Elm, LLC		
(Cambridge on Elm Apartments)	WR-1260, SUB 1	(08/03/2012)
Campus-Raleigh, LLC		
(Campus Crossing at Raleigh Apts.)	WR-745, SUB 4	(09/04/2012)
Carden Place Investors, LLC		
(Carden Place Apartments)	WR-1121, SUB 1	(10/29/2012)
Carlyle Centennial Creek, LLC		
(Century Creek Apartments)	WR-989, SUB 3	(12/21/2012)
Carmel Valley II L.P.		
(Marquis at Carmel Commons Apts.)	WR-71, SUB 6	(10/08/2012)
Carrboro II, LLC		
(Berkshire Manor West Apartments)	WR-788, SUB 3	(12/21/2012)
Cary Parkway Marquis, L. P.		
(Marquis on Cary Parkway Apts.)	WR-522, SUB 5	(01/03/2012)
(Marquis on Cary Pkwy. Apts.)	WR-522, SUB 6	(07/16/2012)
Cary Towne Park, LLC		
(Legends Cary Towne Apartments)	WR-874, SUB 1	(01/17/2012)
(Legends Cary Towne Apartments)	WR-874, SUB 2	(08/23/2012)
Cedar Trace, LLC		
(Cedar Trace Apartments)	WR-897, SUB 4	(09/07/2012)
CEG Friendly Manor, LLC		
(Legacy at Friendly Manor Apts.)	WR-266, SUB 5	(07/24/2012)
CH Realty III/Durham South Place, LLC		
(Alexan Place at South Square I Apts.)	WR-528, SUB 8	(08/22/2012)
CH Realty IV/Notting Hill, L.L.C.		
(Notting Hill Apartments)	WR-852, SUB 3	(01/03/2012)
Chamberlain Place Apartments, LLC		
(Chamberlain Place Apartments)	WR-819, SUB 3	(11/26/2012)
Charleston Place, LLC		
(Charleston Place Apartments)	WR-700, SUB 2	(08/31/2012)
City View Apartments, LLC		
(City View at Southside Apts., Phase I)	WR-702, SUB 4	(09/06/2012)
City View Commercial, LLC		
(City View at Southside Apts., Phase II)	WR-1236, SUB 1	(09/06/2012)

ORDER APPROVING TARIFF REVISION *(Continued)*
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Company	Docket No.	Date
CLNL Acquisition Sub, LLC		
(Colonial Village at Mill Creek Apts.)	WR-975, SUB 17	(03/20/2012)
(Colonial Village at Deerfield Apts.)	WR-975, SUB 18	(03/20/2012)
(Colonial Grand at Legacy Park Apts.)	WR-975, SUB 19	(10/03/2012)
(Glen Eagles Apartments)	WR-975, SUB 20	(10/03/2012)
(Colonial Village at Charleston Place Apts.)	WR-975, SUB 21	(10/03/2012)
(Colonial Village at South Tryon Apts.)	WR-975, SUB 22	(10/03/2012)
(Colonial Village at Deerfield Apts.)	WR-975, SUB 23	(10/03/2012)
(Colonial Village at Stone Pointe Apts.)	WR-975, SUB 24	(10/03/2012)
(Heatherwood Apartments)	WR-975, SUB 25	(10/03/2012)
(Glen Eagles Apartments)	WR-975, SUB 26	(11/19/2012)
(Colonial Village at Mill Creek Apts.)	WR-975, SUB 27	(11/19/2012)
CMF 7 Portfolio, LLC		
(Colonial Village at Greystone Apts.)	WR-976, SUB 4	(10/03/2012)
(Colonial Grand at Huntersville Apts.)	WR-976, SUB 5	(10/03/2012)
CMF 15 Portfolio, LLC		
(Colonial Grand at Crabtree Apts.)	WR-955, SUB 12	(07/27/2012)
(Colonial Grand at Arringdon Apts.)	WR-955, SUB 13	(10/02/2012)
(Colonial Grand at Mallard Lake Apts.)	WR-955, SUB 14	(10/02/2012)
(Colonial Grand at Mallard Creek Apts.)	WR-955, SUB 15	(10/02/2012)
(Colonial Grand at Beverly Crest Apts.)	WR-955, SUB 16	(10/02/2012)
(Colonial Grand at Patterson Pl. Apts.)	WR-955, SUB 17	(10/02/2012)
CND Duraleigh Woods, L.L.C.		
(Duraleigh Woods Apts.)	WR-741, SUB 3	(08/23/2012)
CND Sailboat Bay, L.L.C.		
(Sailboat Bay Apartments)	WR-737, SUB 3	(08/23/2012)
CND Sommerset Place, LLC		
(Sommerset Place Apartments)	WR-746, SUB 3	(08/29/2012)
Cogdill; Narumon Feger & Gregory Scott		
(Rockola Mobile Home Park)	WR-935, SUB 4	(10/05/2012)
Colonial NC, LLC		
(Colonial Townhouse Apartments)	WR-1284, SUB 1	(08/07/2012)
Colonial Realty Limited Partnership		
(The Enclave Apartments)	WR-437, SUB 26	(08/27/2012)
(Colonial Grand at Matthews Commons Apartments)	WR-437, SUB 27	(10/01/2012)
(Colonial Village at Chancellor Park Apartments)	WR-437, SUB 28	(10/01/2012)
(Colonial Grand at Cornelius Apts.)	WR-437, SUB 29	(10/01/2012)
(Colonial Grand at Ayrsley Apts.)	WR-437, SUB 30	(10/01/2012)
(Colonial Grand at Univ. Center Apts.)	WR-437, SUB 31	(10/01/2012)

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Company	Docket No.	Date
Commonwealth Road Properties, LLC		
(Enclave at Pamalee Square Apts.)	WR-1069, SUB 1	(04/09/2012)
(Enclave at Pamalee Square Apts.)	WR-1069, SUB 2	(08/28/2012)
Concord Warwick, LLC		
(Concord Apartments)	WR-526, SUB 4	(09/17/2012)
Copper Mill Village Apartments, LLC		
(Copper Mill Village Apartments)	WR-376, SUB 7	(05/07/2012)
CORE Hunters Chase H, LLC, et al.		
(Hunter's Chase Apartments)	WR-837, SUB 2	(10/22/2012)
Courtney Estates Holdings, LLC		
(Courtney Estates Apartments)	WR-572, SUB 5	(08/29/2012)
Courtney Reserve Apartments, LLC		
(Courtney Reserve Apartments)	WR-553, SUB 4	(12/03/2012)
Courtney Ridge H.E., LLC		
(Courtney Ridge Apartments)	WR-321, SUB 6	(08/21/2012)
CREF Tribute LLC		
(Tribute Apartments)	WR-1195, SUB 1	(08/09/2012)
Crescent Commons Apartments, LLC		
(Crescent Commons Apartments)	WR-460, SUB 5	(09/04/2012)
Crescent Oaks Apartments, LLC		
(Crescent Oaks Apartments)	WR-465, SUB 4	(03/20/2012)
(Crescent Oaks Apartments)	WR-465, SUB 5	(09/25/2012)
Crestmont at Ballantyne Apts., LLC		
(Crestmont at Ballantyne Apts.)	WR-335, SUB 8	(08/01/2012)
CRLP Bruckhaus Street, LLC		
(Colonial Grand at Brier Creek Apts.)	WR-1060, SUB 1	(07/25/2012)
CRLP Creekside Hills Drive LLC		
(Colonial Village at Beaver Creek Apts.)	WR-1172, SUB 1	(10/01/2012)
CRLP Crescent Lane, LLC		
(Colonial Vil. at Matthews Apts.)	WR-977, SUB 2	(10/03/2012)
CRLP Durham, LP		
(Colonial Grand at Research Park Apts.)	WR-411, SUB 6	(10/01/2012)
Crown Ridge Partners, LLC		
(Grand Terraces Apartments)	WR-818, SUB 3	(10/16/2012)
Crowne at Fairlawn Assoc., LP		
(Crowne Park Apartments)	WR-1032, SUB 1	(07/23/2012)
Crowne at Polo Associates, L.P.		
(Crowne Polo Apartments)	WR-1034, SUB 1	(07/23/2012)
Crowne Club Associates, LP		
(Crowne Club Apartments)	WR-1031, SUB 1	(07/23/2012)
Crowne Forest Associates, LP		
(Crowne Oaks Apartments)	WR-1030, SUB 1	(07/23/2012)

ORDER APPROVING TARIFF REVISION *(Continued)*
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Company	Docket No.	Date
Crowne Lake Associates, LP		
(Crowne at James Landing Apts.)	WR-318, SUB 6	(02/06/2012)
CSFB 2007-C2 Summerlyn, LLC		
(Summerlyn Place Apartments)	WR-1302, SUB 1	(11/19/2012)
CSHV Belmont, LLC		
(The Belmont Apartments)	WR-752, SUB 5	(11/13/2012)
CSMC 2007-C3 Elm Street Living, LLC		
(Paces Village Apartments)	WR-1291, SUB 1	(08/03/2012)
CSP Highland Oaks, LLC		
(Highland Oaks Apartments)	WR-1137, SUB 1	(10/29/2012)
CSP Hunt's View, LLC		
(Hunt's View Apartments)	WR-1217, SUB 1	(08/31/2012)
Cumberland Cove Apartments LLC		
(Cumberland Cove Apartments)	WR-200, SUB 8	(07/24/2012)
CWS Carmel Valley Associates, L.P.		
(Marquis of Carmel Valley Apts.)	WR-1267, SUB 1	(10/09/2012)
CWS Palm Valley Ballantyne, L.P., et al.		
(The Preserve at Ballantyne Commons Apts.)	WR-343, SUB 4	(08/06/2012)
CWSFG 91, LLC, et al.		
(Marquis at Preston Apartments)	WR-1207, SUB 1	(07/16/2012)
DDRTC Birkdale Village LLC		
(The Apartments at Birkdale Village)	WR-699, SUB 4	(08/02/2012)
DLS Kernersville, LLC		
(Abbotts Creek Apartments)	WR-19, SUB 6	(01/25/2012)
(Abbotts Creek Apartments)	WR-19, SUB 7	(10/29/2012)
Donathan Cary Limited Partnership		
(Hyde Park Apartments)	WR-558, SUB 6	(07/24/2012)
Donathan/Briarleigh Park Properties, LLC		
(Briarleigh Park Apartments)	WR-797, SUB 5	(10/30/2012)
DRA Cypress Pointe, LP		
(Cypress Pointe Apartments)	WR-863, SUB 4	(09/06/2012)
DRA Lodge at Mallard Creek, LP		
(The Lodge at Mallard Creek Apts.)	WR-854, SUB 4	(09/05/2012)
DRA Quad, LP		
(Quad Apartments)	WR-871, SUB 3	(09/06/2012)
DRA Woodland Park LP		
(Woodland Park Apartments)	WR-861, SUB 3	(09/06/2012)
Duckett, Jr.; Gordon F. & Susan C.		
(Forest Ridge Mobile Home Park)	WR-928, SUB 4	(10/05/2012)

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Company	Docket No.	Date
Dunhill Trace, LLC		
(Dunhill Trace Apartments)	WR-260, SUB 8	(08/09/2012)
Durham Apartment Company, LLC		
(Addington Farms Apartments)	WR-575, SUB 7	(08/22/2012)
Durham Mews Section II Associates LLC		
(The Mews Apartments, Section II)	WR-884, SUB 1	(12/27/2012)
Durham Section I Associates, LLC		
(The Mews Apartments, Section I)	WR-883, SUB 1	(12/27/2012)
Dutch Village Apartments, LLC		
(Twin City Townhomes)	WR-865, SUB 3	(11/06/2012)
E.O. Johnson Properties, LLC		
(Sedgefield Square Apartments)	WR-1191, SUB 1	(04/02/2012)
(Sedgefield Square Apartments)	WR-1191, SUB 2	(07/30/2012)
East Pointe Partners, LLC		
(Stanford Reserve Apartments)	WR-966, SUB 2	(10/16/2012)
Echo Forest, LLC		
(Legacy Arboretum Apartments)	WR-368, SUB 8	(08/01/2012)
Elizabeth Square Acquisition Corp.		
(Elizabeth Square Apartments)	WR-1086, SUB 1	(08/28/2012)
ELPH Station Nine, LLC		
(Station Nine Apartments)	WR-724, SUB 4	(08/22/2012)
Emmett Ramsey		
(Emma Hills Mobile Home Park)	WR-796, SUB 3	(10/05/2012)
Erwin Hills Park, LLC		
(Erwin Hills Mobile Home Park)	WR-946, SUB 3	(09/07/2012)
Erwin Road Apartments Investors, LLC		
(Trinity Commons at Erwin Apts.)	WR-1090, SUB 1	(09/24/2012)
Estates at Charlotte I, LLC		
(1420 Magnolia Apartments)	WR-73, SUB 4	(09/24/2012)
Estates at Meridian, LLC		
(1520 Magnolia Apartments)	WR-434, SUB 1	(10/04/2012)
Ethan Pointe, LLC		
(Ethan Pointe Apartments)	WR-744, SUB 2	(09/10/2012)
Everest Brampton, LP		
(Brampton Moors Apartments)	WR-1091, SUB 2	(12/03/2012)
Ewing; Roy & Frances		
(Pine Valley Mobile Home Park)	WR-994, SUB 3	(09/07/2012)
Forest Hill Apartments, LLC		
(The Reserve at Forest Hills Apts.)	WR-34, SUB 8	(07/24/2012)

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Company	Docket No.	Date
Fairfield Olde Raleigh, LLC		
(Olde Raleigh Apartments)	WR-552, SUB 6	(09/07/2012)
Fairfield Radbourne Lake, LLC		
(The Apartments at Radbourne Lake)	WR-743, SUB 6	(12/04/2012)
Falls River Apartments, LLC		
(Bell Falls River Apartments)	WR-1110, SUB 2	(08/31/2012)
FASF, LLC		
(Cedar Trace IV Apartments)	WR-999, SUB 3	(09/07/2012)
FC Meadowbrook, LLC		
(Meadowbrook Mobile Home Park)	WR-280, SUB 4	(10/08/2012)
FCP West Village Phase I Owner, LLC		
(West Village Apartments)	WR-1251, SUB 1	(08/28/2012)
Forestdale Apartments, LLC		
(Hawthorne at Forestdale Apts.)	WR-1181, SUB 1	(05/29/2012)
(Hawthorne at Forestdale Apts.)	WR-1181, SUB 2	(10/08/2012)
Fortress Park LLC		
(The Park Apartments)	WR-1193, SUB 1	(05/08/2012)
(The Park Apartments)	WR-1193, SUB 2	(09/26/2012)
Fortune Bay Associates, LLC		
(Forest Pointe Apartments)	WR-785, SUB 5	(11/05/2012)
Freedom Property Investors, LLC		
(Carolina Pines Private Community)	WR-589, SUB 6	(01/24/2012)
(Bavarian Point Private Community)	WR-589, SUB 7	(01/24/2012)
Fuller Street Development, LLC		
(West Village Expansion Apts.)	WR-726, SUB 2	(04/23/2012)
(West Village Expansion Apts.)	WR-726, SUB 3	(08/29/2012)
Fund II Meadows, LLC		
(The Meadows Apartments)	WR-846, SUB 4	(09/05/2012)
Fund III Brassfield Park Apts., LLC		
(Bell Brassfield Apartments)	WR-1038, SUB 1	(08/31/2012)
Fund III Bridford Apartments, LLC		
(Bell Bridford Apartments)	WR-1120, SUB 1	(08/31/2012)
Fund III Cranbrook Apartments, LLC		
(Bell Biltmore Park Apartments)	WR-1076, SUB 2	(08/31/2012)
Fund IX CP Charlotte, LLC		
(Matthews Crossing Apartments)	WR-691, SUB 5	(09/17/2012)
Fund IX PR Durham, LLC		
(Pinnacle Ridge Apartments)	WR-518, SUB 5	(04/23/2012)
G & I VI Cape Harbor LP		
(Cape Harbor Apartments)	WR-763, SUB 4	(09/05/2012)

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Company	Docket No.	Date
G & I VI Lake Lynn LP		
(The Reserve at Lake Lynn Apts.)	WR-761, SUB 7	(09/04/2012)
G & I VI Liberty Crossing LP		
(Liberty Crossing Apartments)	WR-760, SUB 4	(10/29/2012)
G & I VI Mallard LP		
(Mallard Creek Apts.)	WR-776, SUB 6	(09/05/2012)
G & I VI Meadows at Kildare LP		
(Meadows at Kildare Apts.)	WR-769, SUB 6	(09/05/2012)
G & I VI Mill Creek LP		
(Mill Creek Apartments)	WR-774, SUB 5	(09/05/2012)
G & I VI Norcroft LP		
(Northlake Apartments)	WR-768, SUB 6	(09/05/2012)
G & I VI Oaks at Weston LP		
(Oaks at Weston Apartments)	WR-778, SUB 6	(08/29/2012)
G & I VI Providence Court LP		
(Providence Court Apartments)	WR-758, SUB 6	(09/04/2012)
G & I VI Ramsgate LP		
(The Crest at West End Apts.)	WR-765, SUB 5	(01/03/2012)
G & I VI The Creek LP		
(The Creek Apartments)	WR-770, SUB 10	(09/05/2012)
(Sharon Crossing Apartments)	WR-770, SUB 11	(09/05/2012)
G & I VI Trinity Park, LP		
(Trinity Park Apartments)	WR-773, SUB 7	(09/05/2012)
G&I VI Clear Run LP		
(Clear Run Apartments)	WR-762, SUB 5	(09/04/2012)
G&I VI Copper Mill LP		
(Copper Mill Apartments)	WR-767, SUB 6	(09/05/2012)
G&I VI Courtney LP		
(Courtney Place Apartments)	WR-775, SUB 7	(09/05/2012)
G&I VI Crossing LP		
(Crossing at Quail Hollow Apts.)	WR-764, SUB 6	(09/05/2012)
G&I VI Crosswinds, LP		
(Crosswinds Apartments)	WR-772, SUB 5	(09/05/2012)
G&I VI Forest Hills, LLC		
(Forest Hills Apartments)	WR-968, SUB 3	(09/06/2012)
G&I VI Harris Pond, LP		
(Harris Pond Apartments)	WR-771, SUB 6	(09/05/2012)
G&I VI Spring Forest LP		
(Spring Forest Apartments)	WR-766, SUB 7	(09/05/2012)
G&I VI Walnut Creek LP		
(Walnut Creek Apartments)	WR-777, SUB 7	(09/05/2012)

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Company	Docket No.	Date
Galleria Partners II, LLC		
(The Crest Apartments at Galleria)	WR-925, SUB 1	(03/12/2012)
GECMC-2007-C1 Treetop Drive LLC		
(Cumberland Trace Apts.)	WR-1126, SUB 1	(09/24/2012)
General Greene, LLC		
(Pinewood Apartments)	WR-486, SUB 3	(04/30/2012)
Grace Park Development, LLC		
(Grace Park Apartments)	WR-893, SUB 3	(12/17/2012)
Gray Property 2204, LLC		
(Abbotts Run Apartments)	WR-278, SUB 5	(09/28/2012)
Gray Property 2205, LLC		
(Cypress Pond at Porter's Neck Apts.)	WR-659, SUB 4	(10/02/2012)
Gray Property, 2105 LLC		
(Alta Grove Apartments)	WR-178, SUB 7	(09/19/2012)
Gray Woodfield Glen, LLC		
(Woodfield Glen Apartments)	WR-1141, SUB 1	(09/25/2012)
GRDF Quarterside, LLC, et al.		
(Quarterside Apartments)	WR-1210, SUB 1	(05/29/2012)
(Quarterside Apartments)	WR-1210, SUB 2	(10/25/2012)
Greenfield Village NC LLC		
(Greenfield Village Mobile HP)	WR-954, SUB 1	(03/20/2012)
Greenville Village, LLC		
(Greenville Village Mobile HP)	WR-648, SUB 4	(06/18/2012)
Greystone WW Company, LLC		
(Greystone at Widewaters Apts.)	WR-517, SUB 4	(07/30/2012)
GS Edinborough Commons, LLC		
(Edinborough Commons Apts.)	WR-475, SUB 7	(08/09/2012)
GS Edinborough Park, LLC		
(Edinborough at the Park Apts.)	WR-476, SUB 5	(08/29/2012)
GS Village, LLC		
(The Village Apartments)	WR-564, SUB 7	(08/09/2012)
Hampton Ridge Partners, LLC		
(Victoria Park Apartments)	WR-901, SUB 3	(10/16/2012)
Hanover Terrace, LLC		
(Hanover Terrace Apartments)	WR-622, SUB 5	(09/24/2012)
Hawthorne Axis Bainbridge, LLC		
(Bainbridge in the Park Apts.)	WR-1024, SUB 1	(02/21/2012)
Hawthorne-Midway Madison Place, LLC		
(Madison Place Apartments)	WR-1300, SUB 1	(11/14/2012)
Hawthorne-Midway Meadow, LLC		
(Hawthorne at the Meadows Apts.)	WR-1307, SUB 1	(11/14/2012)

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Company	Docket No.	Date
Hawthorne-Midway Summerwood, LLC		
(Summerwood Apartments)	WR-1194, SUB 1	(07/06/2012)
(Summerwood Apartments)	WR-1194, SUB 2	(11/14/2012)
Heinmiller Investments, LLC		
(Broadview Mobile Home Park)	WR-1092, SUB 2	(09/07/2012)
Heinmiller; Arthur E. & Florence H.		
(Apple Blossom Mobile HP)	WR-1094, SUB 1	(10/05/2012)
Highland Quarters LLC		
(Muirfield Village Apartments)	WR-520, SUB 6	(09/28/2012)
Highland Village Limited Partnership		
(Highland Village Apartments)	WR-397, SUB 4	(06/04/2012)
Highpoint Associates, LLC		
(Laurel Bluff Apartments)	WR-570, SUB 1	(06/11/2012)
Hillsborough Apartments Partners, LLC		
(Patriot's Pointe Apartments)	WR-1206, SUB 1	(08/31/2012)
Hillsborough Seminole, LLC		
(Ashford Lakes Apartments)	WR-787, SUB 2	(04/16/2012)
(Ashford Lakes Apartments)	WR-787, SUB 3	(12/21/2012)
Holly Hill Properties, LLC		
(Holly Hill Apartments)	WR-192, SUB 6	(08/28/2012)
Holly NC, L.L.C.		
(Holly Hills Apartments)	WR-1290, SUB 1	(08/07/2012)
HTC Preston Reserve, LLC, et al.		
(Bell Preston Reserve Apts.)	WR-1180, SUB 1	(08/31/2012)
Inman Park Investment Group, Inc.		
(Inman Park Apartments)	WR-383, SUB 9	(08/13/2012)
Integra Springs, LLC		
(Integra Springs at Kellswater Apts.)	WR-1036, SUB 2	(04/30/2012)
Joslin Realty, Inc.		
(Grove Park Apartments)	WR-151, SUB 7	(07/31/2012)
K C Realty Investments, LLC		
(Woodland Heights Mobile HP)	WR-950, SUB 3	(10/05/2012)
Kings Park, LLC		
(Redcliffe at Kenton Place Apts.)	WR-349, SUB 8	(04/02/2012)
(Redcliffe at Kenton Place Apts.)	WR-349, SUB 9	(08/31/2012)
Kip-Dell Homes, Inc.		
(Clover Lane Townehomes)	WR-341, SUB 1	(12/31/2012)
KPCLIC, LLC		
(Millbrook Green Apartments)	WR-573, SUB 5	(08/22/2012)

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Company	Docket No.	Date
Kubeck; Bruce A.		
(Faircrest Mobile Home Park)	WR-310, SUB 26	(06/18/2012)
(Interstate Mobile Home Park)	WR-310, SUB 27	(11/13/2012)
(Dogwood Circle Mobile HP)	WR-310, SUB 28	(11/13/2012)
(Cedar Grove Mobile HP)	WR-310, SUB 29	(11/13/2012)
KUWA, LLC		
(Northstone Apartments)	WR-843, SUB 5	(11/06/2012)
Lake Brandt Triad Apt. Portfolio, LLC		
(Lake Brandt Apartments)	WR-495, SUB 4	(09/06/2012)
Lake Cameron, LLC		
(Lake Cameron Apartments)	WR-546, SUB 3	(09/25/2012)
Lakeshore Apartments, LLC		
(The Lodge at Lakeshore Apts.)	WR-649, SUB 4	(09/06/2012)
Landmark at Chesterfield LP		
(Landmark at Chesterfield Apts.)	WR-1174, SUB 1	(10/16/2012)
LaSalle NC, LLC		
(Duke Manor Apartments)	WR-1286, SUB 1	(08/07/2012)
Laurel Wood Associates, LLC		
(Laurel Wood Mobile HP)	WR-1045, SUB 2	(10/05/2012)
LCD Properties, LLC		
(Mountain View Mobile Home Ct.)	WR-932, SUB 3	(10/30/2012)
Lees Chapel Partners, LLC		
(Cross Creek Apartments)	WR-875, SUB 12	(09/06/2012)
(Millbrook Apartments 2)	WR-875, SUB 13	(09/06/2012)
(Chapel Walk Apartments)	WR-875, SUB 14	(09/06/2012)
Legacy Matthews, LLC		
(Legacy Matthews Apartments)	WR-568, SUB 6	(08/01/2012)
Legacy Oaks Apartments, LLC		
(Alta Legacy Oaks Apartments)	WR-972, SUB 3	(08/23/2012)
(Alta Legacy Oaks Apartments)	WR-972, SUB 4	(11/13/2012)
Lincoln Green Apartments, LLC		
(Lincoln Green Apartments)	WR-527, SUB 4	(09/04/2012)
Litchford Park LLC		
(The Park at North Ridge Apts.)	WR-588, SUB 6	(09/04/2012)
Long Creek Club Apartments, LLC		
(Long Creek Apartments)	WR-866, SUB 4	(09/28/2012)
Longview at Northlake, LLC		
(Longview Apartments)	WR-1170, SUB 1	(08/27/2012)
LVP Timber Creek, LLC		
(Beacon Timber Creek Apts.)	WR-717, SUB 5	(09/06/2012)

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Company	Docket No.	Date
LVP Wendover, LLC		
(Camden Wendover Apts.)	WR-719, SUB 3	(01/18/2012)
(Camden Wendover Apts.)	WR-719, SUB 4	(12/21/2012)
Maggard; David		
(Quiet Hollow Mobile HP)	WR-632, SUB 3	(09/07/2012)
Mallard Green, LLC		
(Mallard Green Apartments)	WR-1259, SUB 1	(08/13/2012)
Mallard Lake Apartments, LP		
(Mallard Lake Apartments)	WR-1089, SUB 2	(08/31/2012)
Marsh Realty Company		
(Park Place Apartments)	WR-1154, SUB 3	(07/26/2012)
(Biscayne Apartments)	WR-1154, SUB 4	(07/26/2012)
(Briarcreek Apartments)	WR-1154, SUB 5	(07/26/2012)
Matthews Reserve, LLC		
(Matthews Reserve Apts.)	WR-557, SUB 3	(09/25/2012)
Mayfaire Apartments, LLC		
(Mayfaire Apartments)	WR-345, SUB 4	(12/31/2012)
MB Remington Place, LLC		
(Remington Place Apartments)	WR-461, SUB 5	(02/28/2012)
(Remington Place Apartments)	WR-461, SUB 6	(09/04/2012)
MB The Timbers, LLC		
(The Timbers Apartments)	WR-462, SUB 6	(09/04/2012)
McArthur Partners II, LLC		
(The Heights at McArthur Park Apartments, Phase II)	WR-1124, SUB 1	(06/19/2012)
Mebane Apartments Associates		
(Ashbury Square Apartments)	WR-485, SUB 4	(12/18/2012)
Meridian at Wakefield, LLC		
(Meridian at Wakefield Apts.)	WR-1098, SUB 2	(08/31/2012)
MFREVF-Piedmont, LLC		
(The Piedmont at Ivy Meadow Apts.)	WR-1190, SUB 1	(10/09/2012)
Mid-America Apartments, L. P.		
(Hermitage at Beechtree Apts.)	WR-22, SUB 46	(11/26/2012)
(Providence at Brier Creek Apts.)	WR-22, SUB 47	(11/26/2012)
(Waterford Forest Apartments)	WR-22, SUB 48	(11/26/2012)
(The Corners at Crystal Lake Apts.)	WR-22, SUB 49	(11/26/2012)
(Hue Apartments)	WR-22, SUB 50	(11/26/2012)
(Brier Creek Apts., - Phases I & II)	WR-22, SUB 51	(11/26/2012)
Misty Creek Apartments, LLC		
(Misty Creek Apartments)	WR-1146, SUB 1	(08/27/2012)

ORDER APPROVING TARIFF REVISION *(Continued)*
Orders Issued

Company	Docket No.	Date
Morganton Place Apartments, LLC		
(Morganton Place Apartments)	WR-782, SUB 2	(12/11/2012)
Morreene, LLC		
(Chapel Tower Apartments)	WR-1289, SUB 1	(08/07/2012)
Morrisville Associates, LLC		
(Crabtree Crossing Townhomes Apts.)	WR-879, SUB 1	(08/28/2012)
Moss Enterprises, Inc.		
(Crownpointe Mobile HP)	WR-924, SUB 6	(10/15/2012)
(Mosswood/Twin Oaks MHP)	WR-924, SUB 7	(10/15/2012)
Moss; Allen H.		
(Crestview II Mobile HP)	WR-896, SUB 6	(10/15/2012)
Motley; Carl Winkler & Clyde		
(Indian Creek Mobile Home Park)	WR-1072, SUB 1	(11/14/2012)
Motley; Clyde & Sharon		
(Locust Grove Mobile HP)	WR-1071, SUB 1	(11/14/2012)
MP Creekwood, LLC		
(Village Lakes Apartments)	WR-738, SUB 4	(09/04/2012)
MP Cross Creek, LLC		
(Sardis Place at Matthews Apts.)	WR-736, SUB 4	(09/04/2012)
MP Hunt Club, LLC		
(Hunt Club Apartments)	WR-735, SUB 4	(09/04/2012)
MP Regency Place, LLC		
(Regency Place Apartments)	WR-714, SUB 7	(09/04/2012)
MP The Oaks, LLC		
(The Oaks Apartments)	WR-734, SUB 4	(08/29/2012)
MP The Pointe, LLC		
(The Pointe Apartments)	WR-733, SUB 4	(09/04/2012)
MP The Regency, LLC		
(The Regency Apartments)	WR-740, SUB 4	(09/04/2012)
MP Winterwood, LLC		
(Aspen Peak Apartments)	WR-739, SUB 4	(08/29/2012)
MRP Laurel Oaks, LLC		
(Laurel Oaks Apartments)	WR-507, SUB 2	(05/14/2012)
MRP Laurel Springs, LLC		
(Laurel Springs Apartments)	WR-506, SUB 3	(05/14/2012)
MRWR, LLC		
(Atrium Apartments)	WR-832, SUB 5	(08/08/2012)
MV/ALG River Crossing Limited		
(River Crossing Apartments)	WR-164, SUB 6	(01/23/2012)
MV/ALG Steele Creek Limited		
(Landings at Steele Creek I Apts.)	WR-227, SUB 4	(01/24/2012)

ORDER APPROVING TARIFF REVISION *(Continued)*

Orders Issued

Company	Docket No.	Date
MV/ALG Twin Cedars Limited		
(Twin Cedars I Apartments)	WR-226, SUB 5	(01/23/2012)
New Haw Creek Associates		
(Haw Creek Mews I Apartments)	WR-624, SUB 1	(06/25/2012)
New Haw Creek Section II Associates		
(Haw Creek Mews II Apartments)	WR-625, SUB 1	(06/25/2012)
New Park Ridge Associates, LLC		
(Park Ridge Estates Apartments)	WR-1225, SUB 1	(08/09/2012)
New Willow Ridge Associates, LLC		
(Willow Ridge Apartments)	WR-212, SUB 4	(08/09/2012)
Neyland Apartment Assoc. Two, LLC		
(Independence Park Apartments)	WR-1214, SUB 1	(11/27/2012)
North Carolina Carrboro L.P.		
(Berkshire Manor Apartments)	WR-789, SUB 3	(12/21/2012)
North Carolina Rental Parks Assoc., Ltd.		
(Whispering Pines Mobile HP)	WR-1070, SUB 2	(09/07/2012)
North Timbers Associates L.P.		
(North Timbers Apartments)	WR-285, SUB 6	(08/31/2012)
Northcross Marquis, L.P.		
(The Marquis at Northcross Apts.)	WR-864, SUB 2	(07/30/2012)
Norwalk Street Partners, LLC		
(Andover Park Apartments)	WR-653, SUB 4	(07/25/2012)
NR Alpha Mill Property Owner, LLC		
(Alpha Mill Apartments)	WR-1238, SUB 1	(08/02/2012)
NR Blakeney Property Owner, LLC		
(The Apartments at Blakeney)	WR-1201, SUB 1	(08/02/2012)
Oakhurst Farms of Raleigh, LLC		
(Village of Pickwick Apartments 1)	WR-1018, SUB 2	(04/03/2012)
ORP Lynnwood Park, LLC		
(Lynnwood Park Apartments)	WR-1186, SUB 1	(10/04/2012)
Park Forest Triad Apt. Portfolio, LLC		
(Park Forest Apartments)	WR-493, SUB 4	(09/04/2012)
Parkside Drive, LLC		
(Highlands at Brier Creek Vil. Apts.)	WR-1218, SUB 1	(07/26/2012)
PC Links, LLC		
(Links at Citiside Apartments)	WR-1149, SUB 1	(08/27/2012)
Perimeter Station, LLC		
(Perimeter Station Apartments)	WR-914, SUB 2	(11/26/2012)
Piper Charlotte Apts. L.P.		
(Piper Station Apartments)	WR-941, SUB 2	(03/26/2012)
Plantation Park Apartments, Inc.		
(Plantation Park Apartments)	WR-644, SUB 5	(08/22/2012)

ORDER APPROVING TARIFF REVISION *(Continued)*
Orders Issued

Company	Docket No.	Date
Pleasant Garden Apartments, LLC		
(The Gardens at Anthony House Apts.)	WR-742, SUB 4	(09/06/2012)
POAA, L.L.C.		
(Pines of Ashton Apartments)	WR-834, SUB 7	(03/05/2012)
POAA II, L.L.C.		
(Pines of Ashton Apartments)	WR-1282, SUB 1	(08/07/2012)
PR Oberlin Court, LLC		
(The Apartments at Oberlin Court)	WR-1179, SUB 1	(08/01/2012)
PRG Windsor Square Associates, LLC		
(South Square Townhomes Apts.)	WR-1226, SUB 1	(08/09/2012)
Princeton Marquis, L. P.		
(The Marquis on Edwards Mill Apts.)	WR-503, SUB 5	(07/23/2012)
Princeton Park Apartments, LLC		
(Legacy North Hills Apartments)	WR-541, SUB 8	(08/01/2012)
Providence Park Apartments I, LLC		
(Providence Park Apartments)	WR-284, SUB 9	(07/26/2012)
RAIA Properties NC-2, LLC		
(Birkdale Apartment Homes)	WR-839, SUB 5	(08/21/2012)
RAIA Properties NC-4, LLC		
(One Norman Apartments)	WR-1271, SUB 1	(08/21/2012)
RAIA Self-Storage Montville, LLC, et al.		
(The Enclave at Crossroads Apts.)	WR-890, SUB 6	(08/21/2012)
RCP Briarwood, LLC		
(Briarwood Apartments)	WR-926, SUB 2	(12/04/2012)
Red Chief, LLC		
(Morehead Apartments)	WR-722, SUB 2	(10/02/2012)
REEP-MF Verde NC LLC		
(North City 6 Apartments)	WR-1087, SUB 1	(05/21/2012)
(North City 6 Apartments)	WR-1087, SUB 2	(08/21/2012)
Reserve at Mayfaire, LLC		
(Mayfaire Apartments)	WR-387, SUB 4	(06/26/2012)
Ridgeview MHP, LLC		
(Ridgeview Mobile Home Park)	WR-712, SUB 4	(09/07/2012)
Robinhood Court Apt. Homes, LLC		
(Robinhood Court Apartments)	WR-1051, SUB 2	(01/30/2012)
(Robinhood Court Apartments)	WR-1051, SUB 3	(12/10/2012)
Rockwood Road Apts., LLC		
(Audubon Place Apartments)	WR-964, SUB 2	(12/04/2012)
Star Investments of Cary, LLC		
(Century Oaks Apts., Phase II)	WR-5, SUB 6	(08/14/2012)
Salem Ridge Apartments, LLC		
(Salem Ridge Apartments)	WR-1096, SUB 2	(11/19/2012)

ORDER APPROVING TARIFF REVISION *(Continued)*
Orders Issued

Company	Docket No.	Date
Salem Village Apartments, LLC		
(Salem Village Apartments)	WR-446, SUB 6	(07/26/2012)
SG-Waterford-Morrisville, LLC		
(The Waterford Apartments)	WR-1157, SUB 1	(12/17/2012)
Sherwood MHP, LLC		
(Sherwood Mobile Home Park)	WR-1044, SUB 2	(09/07/2012)
Sherwood Place, LLC		
(Sherwood Place Apts.)	WR-723, SUB 2	(09/26/2012)
Silverton Marquis, LP		
(Marquis at Silverton Apts.)	WR-422, SUB 7	(01/25/2012)
(Marquis at Silverton Apts.)	WR-422, SUB 8	(07/30/2012)
Socal-Thornberry, Inc.		
(Thornberry Apartments)	WR-106, SUB 9	(12/17/2012)
South End Apartments, LLC		
(The Millennium South End Apts.)	WR-1173, SUB 1	(08/21/2012)
Southpoint Crossing Apt. Prop., LLC, et al.		
(Bell Southpoint Apartments)	WR-185, SUB 8	(08/31/2012)
Southwood Realty Company		
(Carriage House Apartments)	WR-910, SUB 8	(02/13/2012)
(Quail Woods Apartments)	WR-910, SUB 9	(02/13/2012)
Sovereign Development Company, LLC		
(Willow Woods Apartments)	WR-784, SUB 4	(09/28/2012)
Spinksville III & Ambiance Parkside, LLC		
(Parkside Village Apartments)	WR-727, SUB 4	(08/06/2012)
Spring Forest TIC, LLC		
(Spring Forest at Deerfield Apts.)	WR-450, SUB 4	(09/07/2012)
Spyglass Capital Partners – Hawk Ridge, LLC		
(Hawk Ridge Apartments)	WR-1182, SUB 1	(07/06/2012)
SRC Northwinds, Inc.		
(Northwinds I and II Apartments)	WR-1254, SUB 1	(11/19/2012)
St. Andrews Place Apartments, LLC		
(Colonial Grand at Wilmington Apts.)	WR-111, SUB 8	(05/21/2012)
Steele Creek Apartments L.P.		
(Landings at Steele Creek II Apts.)	WR-228, SUB 4	(01/24/2012)
Steele Creek Apartments NC, L.P.		
(Alta Steele Creek Apartments)	WR-905, SUB 4	(08/22/2012)
Steeplechase Triad Apt. Portfolio, LLC		
(Steeplechase Apartments)	WR-497, SUB 4	(09/04/2012)
Sill Meadow Village Ltd. Partnership		
(Still Meadow Village Apartments, Phases 1 & 2)	WR-1073, SUB 1	(04/03/2012)

ORDER APPROVING TARIFF REVISION *(Continued)*
Orders Issued

Company	Docket No.	Date
Stone Ridge Apartments, LLC		
(Stone Ridge Apartments)	WR-1175, SUB 1	(09/07/2012)
Stratford Investments, LLC, et al.		
(Stratford Hills Apartments)	WR-1019, SUB 4	(03/26/2012)
(Stratford Apartments)	WR-1019, SUB 5	(03/26/2012)
(Stratford Apartments)	WR-1019, SUB 6	(04/16/2012)
(Stratford Hills Apartments)	WR-1019, SUB 7	(04/16/2012)
Strawberry Hill Associates LP		
(Strawberry Hills Apartments)	WR-293, SUB 7	(07/26/2012)
Strickland Farms Apartments, LLC		
(Strickland Farms Apartments)	WR-1304, SUB 1	(09/11/2012)
Strouse, Greenberg Properties VI, LP		
(Tyvola Centre Apartments)	WR-983, SUB 1	(11/14/2012)
Suncoast Cornerstone, LLC		
(Cornerstone Apartments)	WR-801, SUB 4	(02/13/2012)
(Cornerstone Apartments)	WR-801, SUB 5	(11/20/2012)
Suncoast North Park, LLC		
(North Park Apartments)	WR-808, SUB 5	(09/11/2012)
SVF Weston Lakeside, LLC		
(Apartments at Weston Lakeside)	WR-601, SUB 5	(12/10/2012)
The Forest at Asheville Properties, LLC		
(Bell Forest at Biltmore Park Apts.)	WR-20, SUB 7	(08/31/2012)
Terrace Mews Associates		
(Terrace Mews Apartments)	WR-569, SUB 1	(06/25/2012)
The Apartments at Crossroads, LLC		
(Legacy Crossroads Apartments)	WR-851, SUB 4	(10/17/2012)
The Fairway Apartments, LLC, et al.		
(The Links Apartments)	WR-565, SUB 3	(08/22/2012)
The Grand in Kannapolis, LLC		
(The Grand in Kannapolis Apts.)	WR-965, SUB 1	(05/21/2012)
The Village at Carver Falls II, LLC		
(The Village at Carver Falls Apts.)	WR-563, SUB 2	(04/09/2012)
(The Village at Carver Falls Apts.)	WR-563, SUB 3	(06/11/2012)
Three Oak Property, LLC		
(The Park at Three Oaks Apts.)	WR-405, SUB 1	(09/12/2012)
Timber Crest Apartments, LLC		
(Colonial Village at Timber Crest Apts.)	WR-412, SUB 6	(10/01/2012)
TMP Perry Point, LLC		
(Perry Point Apartments)	WR-1145, SUB 1	(08/07/2012)
Tower Place, L.L.C.		
(Tower Place Apartments)	WR-108, SUB 8	(05/14/2012)

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Company	Docket No.	Date
Triangle Real Estate of Gastonia, Inc.		
(Pinetree Apartments)	WR-1125, SUB 4	(09/10/2012)
(Eagle's Walk Apartments)	WR-1125, SUB 5	(09/10/2012)
Trinity Commons Apartments, LLC		
(Colonial Grand at Trinity Commons Apartments)	WR-415, SUB 6	(07/26/2012)
Triple Overlook, LLC		
(Triple Overlook Mobile HP)	WR-1047, SUB 2	(09/07/2012)
Tucker Acquisition Corporation		
(712 Tucker Apartments)	WR-1039, SUB 3	(12/17/2012)
Twin Cedars Limited Partnership		
(Twin Cedars II Apartments)	WR-225, SUB 5	(01/23/2012)
VAC L.L.L.P.		
(Brook Hill Apartments)	WR-831, SUB 90	(03/05/2012)
(Eastwood Apartments)	WR-831, SUB 101	(08/08/2012)
(Oakwood Apartments)	WR-831, SUB 102	(08/08/2012)
(Chesterfield Apartments)	WR-831, SUB 103	(08/08/2012)
(Briarwood Apartments)	WR-831, SUB 104	(08/08/2012)
(Princeton Apartments)	WR-831, SUB 105	(08/08/2012)
(Rosewood Apartments)	WR-831, SUB 106	(08/08/2012)
Vanstory Apartments, LLC		
(Ashbrook Pointe Apartments)	WR-126, SUB 8	(07/24/2012)
Village at Cliffdale Apartments		
(Village at Cliffdale Apartments)	WR-842, SUB 2	(12/11/2012)
Village Gate Partners, LLC		
(Village Gate Apartments)	WR-934, SUB 2	(07/02/2012)
Wakefield Affordable Housing, LLC		
(Wakefield Hills Apartments)	WR-685, SUB 3	(06/04/2012)
Waterford Square Apts. Associates, LLC		
(Waterford Square Apartments)	WR-251, SUB 4	(03/12/2012)
(Waterford Square Apartments)	WR-251, SUB 5	(09/24/2012)
Waterford Village Gardens Associates, LLC		
(Waterford Village Apartments)	WR-404, SUB 7	(09/12/2012)
Wendover West Apartments, LLC		
(Wendover West Apartments)	WR-1144, SUB 1	(08/27/2012)
West Bloomfield Acres, L.L.C.		
(West Bloomfield Acres Mobile HP)	WR-325, SUB 4	(08/15/2012)
West Market Partners, LLC		
(The Amesbury on West Market Apts.)	WR-749, SUB 4	(09/06/2012)
Westdale Beech Lake, LLC		
(Beech Lake Apartments)	WR-1213, SUB 1	(10/15/2012)

ORDER APPROVING TARIFF REVISION *(Continued)*
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Company	Docket No.	Date
Westdale Chase on Monroe NC, LLC		
(Chase on Monroe Apartments)	WR-635, SUB 5	(09/18/2012)
Westdale Galleria Village, LLC		
(Galleria Apartment Homes)	WR-1224, SUB 1	(08/29/2012)
Westdale NC Summit Creek, Ltd. Partnership		
(Johnston Creek Crossing Apartments)	WR-826, SUB 4	(08/20/2012)
Westdale Peppertree, Ltd. Partnership		
(Peppertree Apartments)	WR-815, SUB 4	(08/20/2012)
Westdale Sabal Point NC, LLC		
(Sabal Point Apartments)	WR-636, SUB 5	(08/20/2012)
Westdale Willow Glen NC, LLC		
(Willow Glen Apartments)	WR-633, SUB 5	(09/18/2012)
Westfield Thorngrove, LLC		
(Thorngrove Apartments)	WR-906, SUB 4	(09/06/2012)
Westmont Commons Apartments, LLC		
(Westmont Commons Apartments)	WR-459, SUB 6	(08/31/2012)
Westmore Apartments, LLC		
(Westmore Apartments)	WR-1109, SUB 1	(08/03/2012)
Westridge Place, LLC		
(Westridge Place Apartments)	WR-637, SUB 2	(09/26/2012)
WF Elizabeth II, LLC		
(Metro 808 Apartments)	WR-1123, SUB 1	(02/27/2012)
Windsor Landing Investments I, LLC, et al.		
(Windsor Landing Apartments)	WR-886, SUB 2	(04/09/2012)
Winkler; Carl K.		
(Mulberry Hill Mobile HP)	WR-887, SUB 2	(11/14/2012)
WMCI Charlotte I, LLC		
(Bexley Commons at Rosedale Apts.)	WR-213, SUB 10	(08/03/2012)
WMCI Charlotte II, LLC		
(Bexley Creekside Apartments)	WR-230, SUB 9	(08/03/2012)
WMCI Charlotte III, LLC		
(Bexley at Lake Norman Apts.)	WR-258, SUB 9	(08/03/2012)
WMCI Charlotte IV, LLC		
(Bexley Crossing at Providence Apts.)	WR-269, SUB 9	(08/03/2012)
WMCI Charlotte V, LLC		
(Bexley at Springs Farm Apts.)	WR-340, SUB 8	(08/06/2012)
WMCI Charlotte VII, LLC		
(Bexley at Davidson Apartments)	WR-392, SUB 7	(08/06/2012)
WMCI Charlotte VIII, LLC		
(Bexley at Matthews Apartments)	WR-466, SUB 7	(08/06/2012)
WMCI Charlotte IX, LLC		
(Bexley Greenway Apartments)	WR-467, SUB 7	(08/06/2012)

ORDER APPROVING TARIFF REVISION *(Continued)*
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Company	Docket No.	Date
WMCI Charlotte X, LLC		
(Bexley Harborside Apartments)	WR-638, SUB 5	(08/06/2012)
WMCI Charlotte XI, LLC		
(Bexley at Steelecroft Apts.)	WR-1117, SUB 2	(08/13/2012)
WMCI Charlotte XII, LLC		
(Bexley Cloisters at Steelecroft Apts.)	WR-1136, SUB 1	(08/03/2012)
WMCI Charlotte XIII, LLC		
(Bexley Village at Concord Mills Apts.)	WR-1189, SUB 1	(07/09/2012)
WMCI Raleigh I, LLC		
(Bexley at Preston Apartments)	WR-327, SUB 7	(08/03/2012)
WMCI Raleigh II, LLC		
(Bexley Park Apartments)	WR-317, SUB 7	(08/03/2012)
WMCI Raleigh III, LLC		
(Bexley at Brier Creek Apartments)	WR-754, SUB 8	(08/06/2012)
WMCI Raleigh IV, LLC		
(Bexley at Heritage Apartments)	WR-803, SUB 2	(08/06/2012)
WMCI Raleigh V, LLC		
(Bexley at Carpenter Village Apts.)	WR-949, SUB 4	(08/06/2012)
Woodberry Asheville Apartments, LLC		
(Woodberry Apartments)	WR-791, SUB 3	(06/11/2012)
Woodlake Downs Associates L.P.		
(Woodlake Downs Apartments)	WR-286, SUB 9	(07/31/2012)
(Woodlake Downs Apartments)	WR-286, SUB 10	(10/08/2012)
Woodland Heights of Burlington, LLC		
(Woodland Heights Apartments)	WR-1050, SUB 1	(11/06/2012)
Woodland Village Apartments LLC		
(Woodland Village Apartments)	WR-1097, SUB 1	(08/28/2012)
Woodlands at Wakefield Plantation		
(Woodlands at Wakefield Apts.)	WR-372, SUB 2	(02/06/2012)
Woodward Communities, LLC		
(Woodward Village Mobile HP)	WR-354, SUB 4	(07/26/2012)
WW Partnership		
(Blue's Crossing Apartments)	WR-850, SUB 2	(05/01/2012)
(Woodland Creek Apartments)	WR-850, SUB 3	(05/01/2012)
Wynslow Park LLC		
(Wynslow Park Apartments)	WR-128, SUB 2	(04/30/2012)
Yorktowne Apartments, LLC		
(Yorktown Club Apartments)	WR-1128, SUB 1	(08/03/2012)
100 Rock Haven, LLC		
(Rock Creek Apartments)	WR-992, SUB 3	(01/09/2012)

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Company	Docket No.	Date
100 Spring Meadow Dr. Apts. Investors LLC		
(Alta Springs Apartments)	WR-47, SUB 8	(08/21/2012)
1052, LLC		
(Clairmont at Farmgate Apts.)	WR-957, SUB 2	(08/20/2012)
1300 Knoll Circle Apts. Investors, LLC		
(The Lodge at Southpoint Apts.)	WR-268, SUB 7	(09/10/2012)
1452 LLC		
(Clairmont at Hillandale Apts.)	WR-1118, SUB 1	(08/17/2012)
1801 Interface Lane Apts. Investors, LLC		
(Autumn Park Apartments)	WR-521, SUB 4	(08/22/2012)
4200 Investments, LLC		
(Villagio Apartment Homes)	WR-1177, SUB 1	(07/09/2012)
4209 Lassiter Mill Road Apts. Investors, LLC		
(Alexan North Hills Apartments)	WR-571, SUB 3	(08/22/2012)
7850 Homestead Mobile Home Park, LLC		
(Homestead Village Mobile HP)	WR-1197, SUB 1	(11/14/2012)

Bel Hickory Grove Holdings -- WR-1054, SUB 2; Reissued Order Approving Tariff Revision *(Kimmerly Glen Apartments)* (09/19/2012)

Bel Ridge Holdings, LLC -- WR-1053, SUB 2; Reissued Order Approving Tariff Revision *(McAlpine Ridge Apartments)* (09/17/2012)

BNP/Chason Ridge LLC -- WR-64, SUB 10; Reissued Order Approving Tariff Revision *(Chason Ridge Apartments)* (03/21/2012)

Carden Place Investors, LLC -- WR-1121, SUB 1; Errata Order *(Carden Pl. Apts.)* (10/29/2012)

City View Apartments, LLC -- WR-702, SUB 3; Order Reissuing Certificate of Authority and Approving Rates *(City View at Southside Apartments, Phase I)* (05/11/2012)

CMF 7 Portfolio, LLC -- WR-976, SUB 4; Errata Order *(Colonial Village at Greystone Apts.)* (12/07/2012)

CWS Palm Valley-Ballantyne, L.P, et al. -- WR-343, SUB 4; Errata Order *(The Preserve at Ballantyne Commons Apartments)* (08/14/2012)

Fund IX PR Durham, LLC -- WR-518, SUB 5; Errata Order *(Pinnacle Ridge Apts.)* (04/24/2012)

Holly Hill Properties, LLC -- WR-192, SUB 6; Errata Order *(Holly Hill Apts.)* (09/07/2012)

Perimeter Station, LLC -- WR-914, SUB 1; Errata Order *(Perimeter Station Apts.)* (02/14/2012)

Wynslow Park, LLC -- WR-128, SUB 2; Errata Order *(Gardens at Wynslow Park Apts.)* (05/01/2012)

ORDERS AND DECISIONS LISTED

ORDER APPROVING TARIFF REVISION (HWCCWA)

Orders Issued

Company	Docket No.	Date
BBR/Oak Hollow, LLC		
(Oak Hollow Apartments)	WR-1009, SUB 4	(07/25/2012)
Brentwood West Company, LLC		
(Brentwood West Apartments)	WR-1160, SUB 2	(11/27/2012)
Brook Dana, LLC		
(Brook Hill Apartments)	WR-1281, SUB 1	(08/07/2012)
CDC-Durham\UC, LLC		
(Duke Court Apartments)	WR-1100, SUB 3	(11/05/2012)
(Duke Villa Apartments)	WR-1100, SUB 4	(11/05/2012)
H.R. Realty Company, LLC		
(Hunting Ridge Apartments)	WR-1161, SUB 2	(11/27/2012)
Montecito Company, LLC		
(Montecito Apartments)	WR-1162, SUB 2	(11/27/2012)
MP Clarion Crossing, LLC		
(Clarion Crossing Apartments)	WR-1078, SUB 2	(08/31/2012)
New Cardinal Woods Associates, LLC		
(Cary Pines Apartments)	WR-1232, SUB 1	(08/09/2012)
New Honeytree Associates, L.P.		
(Honeytree Apartments)	WR-1227, SUB 1	(07/23/2012)
New Woodcreek Associates, LLC		
(Woodcreek Apartments)	WR-1233, SUB 1	(08/09/2012)
PRG Lake Johnson Mews Assoc., LLC		
(Lake Johnson Mews Apartments)	WR-1234, SUB 1	(07/23/2012)
PRG Landmark Associates, LLC		
(The Villages of Lake Boone Trail Apts.)	WR-1229, SUB 1	(07/23/2012)
PRG Village Resort Associates, LLC		
(Glendare Park Apartments)	WR-1230, SUB 1	(11/19/2012)
Q. R. Realty Company, LLC		
(Quail Ridge Apartments)	WR-1159, SUB 2	(11/27/2012)
Schmitz; Robert L.		
(1212 Chapel Hill St. Apartments)	WR-1249, SUB 2	(12/03/2012)
Shellbrook Associates, LP		
(Shellbrook Apartments)	WR-1192, SUB 2	(11/27/2012)
Signature Place, LLC		
(Signature Place Apartments)	WR-1074, SUB 1	(11/15/2012)
Sumare, LP		
(Sumter Square Apartments)	WR-1163, SUB 2	(11/27/2012)

ORDER APPROVING TARIFF REVISION (HWCCWA) *(Continued)*
Orders Issued

Company	Docket No.	Date
Treetop Associates, L.P.		
(Tree Top Apartments)	WR-1231, SUB 1	(07/23/2012)
West Montecito Co., LP		
(Montecito West Apartments)	WR-1164, SUB 2	(11/27/2012)

Schmitz; Robert L. -- WR-1249, SUB 1; Errata Order *(1212 Chapel Hill St. Apts.)* (08/14/2012)

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